ULTRA PETROLEUM

Ultra Petroleum Corp. • 2009 Annual Report

A STRONG FOUNDATION FOR GROWTH

NAS • BILL PICQUET • BOB VIRGIN • BRAD JOHNSON • BRANT WITZEL • BRUCE OSTENDORF • CALLY MCKEE •
MAJEWSKI • DAVE SMITH • DEBBIE GHANI • DOUG SELVIUS • DWAYNE JOHNSTON • ERIC POBUDA • ERIK WIL-
LLIAMS • HENRY LAW • JAMES LAIN • JANA DITTON • JASON GAINES • JEANETTE BOWEN • JIM PORTER • JIM
ER • JOSH REIN • JULIE DANVERS • JUSTIN SANDIFER • KELLY PREUIT • KELLY WHITLEY • KENT ROGERS • KENT
KELMAN • MAREE DELGADO • MARK POTTER • MARK SMITH • MARY POBUDA • MATTHEW HEDTKE • MICHAEL
ANDERSON • PRESTON VENABLE • RALPH TROTTER • REBECCA TOWNSEND • REYNE JOHN • RHONDA
IEHN • RYAN LEWIS • SALLY ZINKE • SAM MCCLURE • SARAH GACH • SARAH SANCHEZ • SCOTT ROGERS •
OON • TERRY ALLEN • TIM WAITE • TOM WILSON • TROY GRAHAM • TYLER BELL • WENDY BOMAN

TO OUR SHAREHOLDERS

We owe much of our success to the skills and talents of our committed and caring employees who total fewer than 100 folks today. In 2009, they weathered an economic crisis, suffered through a volatile commodity price environment, and still delivered top-tier performance.

Recently, I read a report where the author simply stated that the best exploration and production companies are those that add oil and natural gas reserves cheaply and produce them at a low cost. Once again in 2009, Ultra Petroleum added reserves at a very attractive cost and increased production to a new record with an all-in cost structure that is probably the lowest in the industry. As a result, we avoided the trap of profitless growth and generated industry-leading returns.

In addition, we removed the resource uncertainty surrounding our Marcellus position and maintained our balance sheet flexibility so we could bid constructively for additional Marcellus resource and fund it with attractively priced, long-term debt. Let me share with you in greater detail the strong results we achieved in 2009.

A primary driver of long-term value creation for an E&P company is growth in its oil and natural gas reserves. In 2009, our proved reserves increased to 3.9 Tcfe, or 11 percent over 2008. We continue to be conservative in recognizing our proved reserves. As evidence of this, we have not included any proved undeveloped locations from our Marcellus position, and we have not included any material reserve additions attributable to the new, more generous SEC rules. Nevertheless, our $1.29 per Mcfe finding and development cost places us on the lower end in industry comparisons.

Despite reducing our capital expenditure budget from $950.0 million in 2008 to $735.0 million in 2009 due to deteriorating commodity prices, we established a new annual record for production. Total production increased 24 percent to an unprecedented 180.1 Bcfe compared to 145.3 Bcfe in 2008. We spent $600.0 million to develop our world class, legacy Wyoming resource base and brought on stream 228 gross (107 net) new wells in Pinedale. Based on encouraging success early in the year, we expanded our Marcellus shale activity and devoted $135.0 million to this growing opportunity in Pennsylvania. Our exploration efforts in the Marcellus focused on commencing a horizontal well drilling program and further de-risking our acreage geologically.

We are keenly focused on maintaining our low-cost competitive advantage. Our 2009 all-in cost of $2.61 per Mcfe underscores our core competency as the low-cost producer in North America and further validates our profitability can withstand the troughs of the commodity price cycle. Enduring the commodity price meltdown of 2009 did not blemish Ultra's proven track record of consistent growth and returns. Remarkably, we earned a return on equity of 32 percent and 18 percent return on capital.

The decision made a few years ago to support construction of the Rockies Express Pipeline has borne fruit with the historical discount associated with Rockies natural gas production all but disappearing. The relative improvement in Rockies gas prices has further strengthened our profitable margins.

Our disciplined business focus affords us the unique ability to grow without stressing our healthy balance sheet. Early in 2009 we placed $235.0 million of long-term debt as a cautionary item to enhance liquidity.

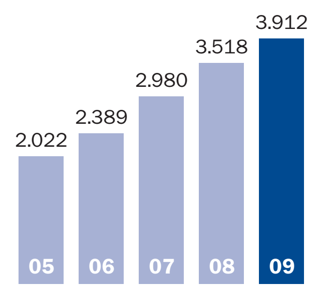
We strategically increased the scale of our Marcellus position with assets that rival the returns of our current Pennsylvania acreage. In late 2009, we announced an acquisition of 80,000 net acres, increasing our net resource potential in the Marcellus. To fund the acquisition, we opportunistically secured additional attractively priced, long-term debt. Both the acquisition and associated debt financing closed in the first quarter of 2010.

Looking ahead to 2010, we have established a capital budget of $1,450.0 million of which roughly 60 percent is allocated to our Lance tight gas Wyoming asset and 40 percent to our growing Marcellus shale natural gas Pennsylvania resource. We plan to produce 215 Bcfe to achieve our 20 percent production growth target.

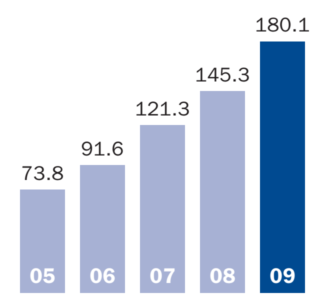
In closing, Kiplinger recently named Ultra Petroleum one of the "Top 25 Stocks of the Decade," based on a ten-year annualized return of 62 percent. We look forward to another decade of positive returns!

Sincerely,

Michael D. Watford
Chairman, President and
Chief Executive Officer



PROVED RESERVES – Tcfe



PRODUCTION – Bcfe

AARON STERCK • ADRIANN PALUMBO • ALAN BOYER • ANDREA PAULSEN • ANNETTE VOSKIAN • BELINDA SA
CARL BRACKLEIN • CARLOS MARTINEZ • CHUCK SNYDER • CODY HILL • DAN BULFER • DAVE HODGES • DAV
LIAMS • ERIKA TOKARZ • FRED ARCHAMBAULT • GARLAND SHAW • GARRETT SMITH • GREG SHORT • GREG
PREVOST • JOE GARCIA • JOE MURDOCK • JOHN LUSTER • JOHN WALTER • JOSEPH COMMODORE • JOSEPH LUS
WILKINSON • KEVIN WRIGHT • LARRY BRYAN • LARRY TAVEGIA • LINDA MEYER • LOREN KJORSTAD • MARC B
BLACKSTONE • MICHAEL WATFORD • MIKE HELWIG • NICKI SMALDONE • NORMA MENDEZ • PRESTON
SNYDER • RICHARD SEIFERT • RICKY LITZEL • ROBIN FOUNTAIN • RON AUFLICK • RON SHERBROOK • RYAN
SHANE DEAL • SHANE REES • STACI GORDON • STUART NANCE • TAMMY WIDHALM • TERESA BRA

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, 2009

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

(Registrant's telephone number, including area code)
(281) 876-0120

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 $5,906,164,446 as of June 30, 2009 (based on the last reported sales price of $39.00 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 17, 2010 was 152,068,210.

Documents incorporated by reference: The definitive Proxy Statement for the 2010 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2009, 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.
- *BOE* — One barrel of oil equivalent, converting natural gas to oil at the ratio of 6 Mcf of natural gas to 1 Bbl of oil.
- *BTU* — British Thermal Unit.
- *Condensate* — An oil-like liquid produced in association with natural gas production that condenses from natural gas as it is produced and delivered into a separator or similar equipment and collected in tanks at each well 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 or condensate to natural gas at the ratio of 1 Bbl of oil or condensate to 6 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.

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 unweighted, 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 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 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.

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.

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.

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 The Yukon Territory, Canada pursuant to Section 190 of the *Business Corporations Act* (Yukon Territory). The Company's operations are primarily located in the Green River Basin of southwest Wyoming and 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 "Financials" 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., Manager, Investor Relations, 363 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.

Oil and Gas Properties Overview

Ultra's current operations in southwest Wyoming are focused on developing the Company's position in a tight gas sand trend located in the Green River Basin with targets in the 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 both the Lance (found at subsurface depths of approximately 8,000 to 12,000 feet) and Mesaverde (found at subsurface depths of approximately 12,000 to 14,000 feet) in the Pinedale and Jonah fields area of Sublette County, Wyoming. As of December 31, 2009, Ultra owned interests in approximately 112,000 gross (56,000 net) acres in Wyoming covering approximately 190 square miles.

Ultra's current operations in north-central Pennsylvania are focused on exploring, developing and expanding its position in the Marcellus Shale and deeper horizons. At December 31, 2009, the Company owned interests in approximately 326,000 gross (169,000 net) acres in Pennsylvania.

Business Strategy

Ultra's mission is to profitably grow an upstream oil and gas company for the long-term benefit of its shareholders. Ultra's strategy includes building a robust portfolio of high return investment opportunities, maintaining a disciplined approach to capital investment, maximizing earnings and cash flows by controlling costs and maintaining financial flexibility.

High Return Portfolio. Ultra maintains a portfolio of properties that provide long-term growth through development in areas that support sustainable, lower-risk, repeatable, high return drilling projects. The Company continually evaluates opportunities for the acquisition, exploration and development of additional oil and natural gas properties that afford risk-adjusted returns in excess of or equal to its current set of investment alternatives.

Disciplined Capital Investment. The Company's business strategy involves the regular review of its investment opportunities in order to optimize return to its shareholders. Over the past ten years, Ultra has consistently delivered meaningful reserve and production growth while providing significant returns to its shareholders. In 2009, oil and natural gas production increased 24% over 2008 levels and estimated proved reserves increased 11% to 3.9 Tcfe from 3.5 Tcfe with return on capital employed of 18% and return on equity of 32%.

Low Cost Producer. Ultra strives to maintain one of the lowest cost structures in the industry in terms of both adding and producing oil and natural gas reserves. The Company continues to focus on improving its drilling and production results through the use of advanced technologies and detailed technical analysis of its properties.

Financial Flexibility. Preserving financial flexibility and a strong balance sheet are also strategic to Ultra's business philosophy. At December 31, 2009, the Company had cash on hand of $14.3 million and outstanding debt was $795.0 million. Consistent with this strategy and subsequent to year-end 2009, the Company issued $500.0 million of senior notes at an average interest rate of 5.46% and a weighted average term of 10.6 years. As a result of the issuance, the availability under the Company's revolving credit facility increased to approximately $335.0 million and the debt maturity profile lengthened to over eight years due to adding tranches of 12 and 15 year debt while the Company's weighted average cost of debt remains at approximately 5.5%.

Green River Basin, Wyoming

During 2009, the Company participated in the drilling of 222 wells in Wyoming and continued to improve its drilling and completion efficiency on its operated wells as measured by spud to total depth. During 2009, the average drilling days decreased 17% from 2008 levels to 20 days from spud to total depth. In addition, the Company's average well cost decreased from $5.5 million per well during 2008 to $5.0 million during 2009, increasing both the present value and rate of return on these wells. This 9% reduction in costs is a direct result of fewer drilling days, fewer rig moves associated with pad drilling and lower cost of services. These cost reductions were accomplished while simultaneously drilling deeper wells and completing more frac stages per well.

During 2010, the Company plans to continue its ongoing development program of its acreage position in the tight gas sand trend in the Green River Basin in southwest Wyoming. The Company expects that wells drilled during 2010 will target the sands of the upper Cretaceous Lance Pool in the Pinedale and Jonah fields.

Additionally, the Company plans to continue its assessment of increased density drilling to more efficiently recover the vast resources present in the area. Currently, essentially all of the Pinedale field is approved by the WOGCC for 16 wells per 160-acre government quarter section (10-acre equivalent). Pilot activities are planned to continue in 2010 in areas approved for testing of well density of 32 wells per 160-acre government quarter section (5-acre equivalent). 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).

All of the Company's drilling activity is conducted utilizing its extensive integrated geological and geophysical data set. This data set is being utilized to map the potentially productive intervals, to identify areas for future extension of the Lance fairway and to identify deeper objectives which may warrant drilling.

Pennsylvania

During 2009, the Company participated in the drilling of 35 horizontal Marcellus wells and two vertical Oriskany wells. The Company also completed a 3-D seismic survey in the Marshlands area. The Company is actively leveraging its Pinedale experience by translating its Wyoming directional drilling, completion and production knowledge to the Marcellus.

During 2010, the Company plans to expand its exploration and development activities in the Middle Devonian Marcellus Shale play on its acreage position in Pennsylvania. Ultra's current activities are located in Potter, Tioga, Bradford and Lycoming counties. Activities include lease acquisition, 3-D seismic, drilling, completion, infrastructure construction and production operations. The Company's activities are focused in the north-central counties of Pennsylvania where the Company believes favorable Marcellus Shale properties exist for economic development.

In December 2009, the Company signed a purchase and sale agreement to acquire additional acreage in the Pennsylvania Marcellus Shale (the deep rights), strategically increasing the scale of its Marcellus position. The transaction closed on February 22, 2010 with an effective date of October 1, 2009. At the closing, the Company acquired 78,221 net acres in the deep rights, for a purchase price of $333.0 million, subject to post closing adjustments. The Company may acquire additional interests in these net acres at subsequent closings if the Sellers cure title defects as provided in the purchase agreement. (See Note 14 to the Company's Consolidated Financial Statements included in this report).

Marketing and Pricing

Ultra derives its revenues principally from the sale of its natural gas and associated condensate production from wells operated by the Company and others in the Green River Basin in southwest Wyoming. A small, but increasing portion of the Company's revenues is associated with gas sales from wells located in the Appalachian Basin in Pennsylvania. Historically, the Company's revenues have been determined, to a large degree, by prevailing natural gas prices for production situated in the Rocky Mountain region of the United States, specifically, southwest Wyoming. With the completion of the Rockies Express Pipeline, LLC ("REX") during 2009, a substantial portion of the Company's revenues are now determined by natural gas market prices in the Midwestern and Eastern regions of the United States. Energy commodity prices in general, and the Company's regional prices in particular, have been highly volatile, and such high levels of volatility are expected to continue in the future.

Supplies of natural gas in the U.S. grew rapidly during 2008 in response to higher natural gas prices and higher levels of drilling activity. Natural gas prices peaked in mid-2008 and then declined dramatically, while simultaneously, the world economy fell into recession. These coincident events materially reduced gas demand and resulted in an imbalance between natural gas supply and demand. This supply/demand imbalance persisted throughout 2009, resulting in reductions in drilling activity directed toward natural gas and in materially lower gas prices. Furthermore, this imbalance caused record high levels of natural gas in storage in the U.S. and Canada at the beginning of the traditional storage withdrawal season (November 1st). Mild weather in November 2009 lead to a delay in the commencement of storage withdrawals and resulted in further surpluses in gas storage inventory levels relative to historical averages. Since the end of November 2009, temperatures in the U.S. and in other parts of the world have generally been colder than normal, and storage levels have been drawn down to levels more consistent with historical averages.

The Company, from time to time, in the regular course of its business, hedges a portion of its natural gas production primarily through the use of financial swaps with creditworthy financial counterparties, or through the use of fixed price, forward sales of physical gas. The Company may elect to hedge additional portions of its forecasted natural gas production in the future, in much the same manner as it has done previously. The Company's hedging policy limits the amounts of resources hedged to not more than 50% of its forecast production without Board approval. 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. For a more detailed description of the Company's hedging activities, see Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

In response to the lower price environment that began to emerge in mid-to-late 2008, the Company began to more aggressively hedge its exposure to lower natural gas prices by entering into forward sales for 2009 through 2011. This strategy of hedging resulted in greater price certainty for the Company's production and helped protect the Company's 2009 capital investment program. During the first quarter of 2009, the Company elected to convert its physical, fixed price, forward natural gas sales to physical, indexed natural gas sales combined with financial swaps whereby the Company receives the fixed price and pays the variable price. This conversion allowed the Company to retain a higher level of discretion to shut-in physical natural gas sales in response to lower prices while still receiving the benefits of its hedges with prices that were higher than market.

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). Historically, the Company's customers were predominately located in the western United States — primarily California and the Pacific Northwest, as well as the Front Range area of Colorado and in Utah. With the REX pipeline operational into Ohio and with the addition of new gas production in Pennsylvania, the Company's customer base has expanded to include a significant number of new customers situated in the Midwestern and Eastern 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. The Company maintains credit policies intended to mitigate the risk of uncollectible accounts receivable related to its sale of natural gas. The Company did not have any outstanding, uncollectible accounts for its natural gas sales at December 31, 2009.

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 in southwest Wyoming. Under these agreements, the midstream service providers have routinely expanded their facility's capacity 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 from Wyoming.

In Pennsylvania, the Company and its partners are constructing gas gathering pipelines and facilities, compression facilities and pipeline delivery stations to gather production from its newly completed natural gas wells. Construction on these facilities will continue throughout 2010 allowing the Company to manage its midstream capacity to coincide with increased capacity requirements from its drilling activities. 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 facilities of this type will not be required in the future to accommodate the Company's production.

Pipeline infrastructure. The Company has previously taken and continues to take action to expand the pipeline infrastructure available to move its natural gas supplies away from southwest Wyoming to provide sufficient capacity to transport its natural gas production and to provide for reasonable prices for its natural gas in the future.

The Company agreed to become an anchor shipper on REX, sponsored by subsidiaries of Kinder Morgan, Conoco Phillips, and Sempra Energy. 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 capacity of 200 MMMBtu per day of natural gas for a term of 10 years commencing with initial transportation in January 2008. 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 REX pipeline was built in multiple phases: REX West (Wyoming to Missouri — in service in 2008) and REX East (Missouri to Clarington, Ohio — in service in November 2009), with an expanded capacity of 1.8 Bcf per day. 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. This additional capacity will provide the Company with the ability to move additional volumes from its producing wells in Wyoming to markets in the eastern U.S.

Two additional new pipeline projects originating in Wyoming and designed to transport natural gas to markets not currently accessible to Wyoming producers have been announced and are in final stages of pre-construction sanctioning and approvals. The Ruby Pipeline, sponsored by El Paso Corporation, and the Bison Pipeline, sponsored by TransCanada Pipeline Corp., have received final EIS approvals from the FERC and are expected to begin construction in 2010. These two pipelines, when completed, will add aggregate export pipeline capacity for Rockies\Wyoming gas of approximately 1.7 Bcf per day, a 20% increase over current levels.

Basis differentials. The market price for natural gas in the Rockies generally, and in southwest Wyoming specifically, is influenced by a number of regional and national factors, all of which are unpredictable and are beyond the Company's ability to control. These factors include, among others, weather, natural gas supplies, natural gas demand, and natural gas pipeline capacity to export gas from the Rockies. The Rocky Mountain region is typically a net exporter of natural gas because local natural gas production typically exceeds local demand during non-winter months. As a result, natural gas production in southwest Wyoming has historically 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 the costs associated with transporting the Company's gas to markets in other regions or states. They are also reflective of the general relative abundance of, or lack of, export pipeline capacity to move gas out of the Rockies. NW Rockies basis was generally wide since 2006 but improved during the latter portion of 2009 and is anticipated to remain favorable in 2010 through 2012 mainly as a result of the completion of the REX pipeline into Ohio, as discussed above (See Pipeline Infrastructure).

The table below provides a historical and future perspective on average annual basis differentials for Wyoming natural gas (NW Rockies) and premium markets in the Northeast (Dominion South). The basis differential is expressed as a percentage of the Henry Hub price as reported by Platt's on December 31, 2009.

	2006	2007	2008	2009	2010	2011	2012
NW Rockies	78%	58%	69%	77%	94%	92%	90%
Dominion South	104%	105%	105%	107%	104%	103%	102%

Oil Marketing

The Company markets its Wyoming condensate to various purchasers. The pricing of the Company's condensate production varied significantly during 2009 and is based on New York Mercantile Exchange crude futures daily settlement prices, less a negotiated location and 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.

Historically, the Company's condensate production was gathered from its Wyoming well locations by tanker trucks and then shipped to other locations for injection into crude oil pipelines or other facilities. During 2009, the Company initiated service on the first two (of four proposed) central gathering facilities. These facilities are part of the Company's liquids gathering system designed to gather condensate and water from various leases and wells operated by the Company as contemplated under the Supplemental Environment Impact Statement ("SEIS") Record of Decision ("ROD") as discussed below in Environmental Matters. The condensate and water are transported to central points in the field where condensate can be loaded into trucks or delivered into pipelines.

Significant Counterparties

In 2009, the Company had three significant counterparties associated with sales of its natural gas production and commodity derivatives contracts. Sales and settlements of derivative contracts to Sempra Energy Trading Corp., J Aron & Company and JP Morgan Chase Bank, N.A. were $144.9 million, $101.3 million, and $97.1 million, respectively, which accounted for 16.2%, 11.3% and 10.8% of the Company's total 2009 revenues (including realized gains on commodity derivatives), respectively. At December 31, 2009, the Company had outstanding receivables (which were received in full in January 2010) from Sempra Energy Trading Corp., J Aron & Company and JP Morgan Chase Bank, N.A. totaling $19.7 million.

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 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 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 drilling and spacing unit. Results of all of these pilot projects were utilized in acquiring approval from the WOGCC in November 2004 to increase the overall density of development for the Jonah Field to eight wells per 80-acre drilling and spacing unit.

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 2008, 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. At the end of 2007, there were over a dozen different infill density and pilot project orders granted by the WOGCC and currently in place on the Pinedale field. While a very minor portion of the Pinedale field still provides for one well per 40 acres, a succession of WOGGC approvals through yearend 2007 now provide for and range from two wells per 40 acres (20-acre density) up to a 32 well per 160-acre pilot project (5-acre density). The northern portion of the Pinedale field is operated by Questar Exploration and Production Company ("Questar") in which the Company is a working interest partner and owns a working interest in the majority of Questar's acreage. Questar's most recent infill density application, approved in July 2007, provided for the drilling of 16 wells per quarter section (10-acre density). With respect to the central portion of the Pinedale field, approval was granted for development on a two wells per 40-acre density in November 2005. Ultra operates the majority of the acreage covered by this approval. Within this two wells per 40-acre density area and in an additional area in the southern portion of the Pinedale field, in July 2007, Ultra and other operators received approval from the WOGCC to provide for the drilling of 16 wells per quarter section (10-acre density). Finally, in December 2007, approximately 2% (640 gross acres) of the productive area of the Pinedale field in which Company owns a working interest has now been approved by the WOGCC for drilling at the equivalent of 5-acre density; an additional 73% (26,888 gross acres) has been approved for drilling at equivalent 10-acre density; an additional 18% (6,687 gross acres) has been approved for drilling at equivalent 20-acre density, with 7% (2,400 gross acres) still under the state wide 40-acre well density rules. Further drilling and testing within the areas approved for increased density continues, the results of which are being evaluated to determine the overall development strategy for the Pinedale field and the ultimate need for future increases in development density.

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 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 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.

Also as part of the 2008 SEIS ROD, Ultra has offered to suspend additional activity for at least five years from the signing of the SEIS ROD on certain leases. After the five-year period, leases under federal suspension and/or term no surface occupancy will be considered for conversion to "available for development" when a comparable acreage in the core area of the PAPA has been returned to a functioning habitat.

In 2007 and 2008 Ultra entered five groundwater supply wells into the Wyoming Department of Environmental Quality Voluntary Remediation Program ("VRP"). These wells exceeded the Department of Environmental Quality's ("DEQ") minimum clean-up levels ("MCL"). Four of the five wells are now non-detect or below the MCL. The remaining well has a very low levels of contaminates and a remediation plan has been submitted to the DEQ for this well. Ultra encountered another water well that exceeded the MCL. This well was remediated and the contaminate levels were non-detect before it was entered into the VRP.

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, state and federal regulation of oil and natural gas production and transportation, including regulations governing environmental quality and pollution control and state 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. For example, a productive natural gas well may be shut-in because of a lack of an available natural gas pipeline in the areas in which the Company may conduct operations. 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 agencies, which can affect our operations.

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 FERC under the Natural Gas Act, as well as under Section 311 of the Natural Gas Policy Act. Since 1985, the FERC has 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. On February 9, 2000, the FERC issued a final rule concerning alternatives to its traditional cost-of-service rate-making methodology to establish the rates interstate pipelines may charge for services. The final rule revises the FERC's pricing policy and current regulatory framework to improve the efficiency of the market and further enhance competition in natural gas markets. The FERC has also issued several other generally pro-competitive policy statements and initiatives affecting rates and other aspects of pipeline transportation of natural gas. On May 31, 2005, the FERC generally reaffirmed its policy allowing interstate pipelines to selectively discount their rates in order to meet competition from other interstate pipelines. On June 15, 2006, the FERC issued an order in which it declined to establish uniform standards for natural gas quality and interchangeability, opting instead for a pipeline-by-pipeline approach. On June 19, 2006, in order to facilitate development of new storage capacity, the FERC established criteria to allow providers to charge market-based (i.e. negotiated) rates for storage services. On June 19, 2008, the FERC removed the rate ceiling on short-term releases by shippers of interstate pipeline transportation capacity.

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.

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") or Minerals Management Service, Bureau of Indian Affairs, tribal or other applicable federal, state and/or Indian Tribal agencies.

The Mineral Leasing Act of 1920 ("Mineral Act") prohibits direct or indirect ownership of any interest in federal onshore oil and gas leases by a foreign citizen of a country that denies "similar or like privileges" to citizens of the United States. Such restrictions on citizens of a non-reciprocal country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and gas lease. If this restriction is violated, the corporation's lease can be canceled in a proceeding instituted by the United States Attorney General. Although the regulations of the BLM (which administers 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, which could be determined to be citizens of a non-reciprocal country under the Mineral Act.

Environmental Regulations

General. The Company's exploration, drilling and production activities from wells 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. 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, including proposed amendments to the federal Safe Drinking Water Act ("SDWA") related to hydraulic fracturing operations, it is possible the Company could be required to remediate property, including ground water, containing or impacted by operations by the Company or by such third party operators, or 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 are considering adopting stricter disposal standards for non-hazardous wastes. Furthermore, certain wastes generated by the Company's oil and natural gas operations that are currently exempt from treatment as Hazardous Wastes may in the future be designated as Hazardous Wastes under the RCRA or other applicable statutes, and therefore be subject to more rigorous and costly operating and disposal requirements.

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. To its knowledge, the Company has not been named a PRP under CERCLA nor have any prior owners or operators of its properties been named as PRP's 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 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.

Clean Water Act. The Clean Water Act ("CWA") restricts the discharge of wastes, including produced waters and other oil and natural gas wastes, into waters of the United States, a term broadly defined. Under the Clean Water Act, permits must be obtained for the routine discharge 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.

Application of Safe Drinking Water Act to Fracturing. The Safe Drinking Water Act ("SDWA") regulates, among other things, underground injection operations. Recent legislative activity has occurred which, if successful, would impose additional regulation under the SDWA upon the use of hydraulic fracturing fluids. The U.S. Senate and House of Representatives are considering two companion bills entitled the "Fracturing Responsibility and Chemical Awareness Act of 2009." If enacted, the legislation would impose on our hydraulic fracturing operations permit and financial assurance requirements, requirements that we adhere to construction specifications, fulfill monitoring, reporting and recordkeeping obligations, and meet plugging and abandonment requirements. In addition to subjecting the injection of hydraulic fracturing to the SDWA regulatory and permitting requirements, the proposed legislation would require the disclosure of the chemicals within the hydraulic fluids, which could make it easier for third parties opposing hydraulic fracturing to initiate legal proceedings based on allegations that specific chemicals used in the process could adversely affect ground water. Neither piece of legislation has been passed. If this or similar legislation is enacted, we could incur substantial compliance costs and the requirements could negatively impact our ability to conduct fracturing activities on our assets.

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 federal land use and may materially delay or prohibit land access for oil and natural gas development. If the Company were to have a portion of its leases designated as critical or suitable habitat, it may adversely impact the value of the affected leases.

OSHA and other Regulations. The Company is subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require a company to organize and/or disclose information about hazardous materials used or produced in its operations.

Climate Change Legislation. 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. The U.S. House of Representatives passed and the U.S. Senate is considering climate change-related legislation to regulate GHG emissions that could affect the Company's operations and its regulatory costs, as well as the value of oil and natural gas generally. Independent of that legislation, the EPA is moving forward with climate change-related regulatory initiatives, having found GHGs may reasonably be anticipated to endanger human health and the environment. These regulatory initiatives could also affect our operations and costs. 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. Ultra's current activities are not applicable as a "covered entity" in respect to climate change legislation because its activities do not exceed 25,000 tons of carbon dioxide equivalent.

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, 2009, the Company had 94 full-time employees, including officers.

Item 1A. *Risk Factors.*

There are inherent limitations in all control systems and failure of our controls and procedures to detect error or fraud could seriously harm our business and results of operations.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our internal controls and disclosure controls will prevent all possible error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, no evaluation of our controls can provide absolute assurance that all control issues and instances of fraud, if any, in our Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Further, controls can be circumvented by the individual acts of some persons or by collusion of two or more persons. The design of any system of controls is based in part upon the likelihood of future events, and there can be no assurance that any design will succeed in achieving its intended goals under all potential future conditions. Over time, a control may become inadequate because of changes in conditions or the degree of compliance with its policies or procedures may deteriorate. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur without detection.

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, results of 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 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 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. Historically, oil and natural gas prices have fluctuated widely.

The present value, discounted at 10%, of the pre-tax future net cash flows attributable to our 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 unweighted, arithmetic average of the first-day-of the-month price for each month within such period, adjusted for quality and transportation. The costs to produce the reserves remain constant at the costs prevailing on the date of the estimate.

Actual current and future prices and costs may be materially higher or lower. 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 the financial or personnel resources of the Company 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 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; 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 capacity, including facilities owned and operated by third parties;
- the proximity of natural gas production to those 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, we may be unable to market all of our oil and natural gas that we produce. In addition, we may be unable to obtain favorable prices for the oil and natural gas we produce.

Our derivative transactions may limit our gains and expose us to other risks.

We enter into transactions with derivative instruments 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 instruments. 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 instrument fails to perform the contracts.

A decrease in oil and natural gas prices may adversely affect our results of operations and financial condition.

Energy commodity prices in general, and our regional prices in particular, have been historically highly volatile, and such high levels of volatility are expected to continue in the future. We cannot accurately predict the market prices that we will receive for the sale of our natural gas, condensate, or oil production.

Oil and natural gas prices are subject to a variety of additional factors beyond our control, such as large fluctuations in oil and natural gas prices in response to relatively minor changes in the supply of and demand for oil and natural gas and market uncertainty. These factors include but are not limited to weather conditions in the United States, the condition of the United States economy, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and natural gas, the price of foreign oil and natural gas imports and the availability of alternate fuel sources and transportation interruption. Any substantial and extended decline in the price of oil or natural gas could have an adverse effect on the carrying value of our proved reserves, borrowing capacity, our ability to obtain additional capital, and the Company's revenues, profitability and cash flows from operations.

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition and divestiture and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

If the United States experiences a sustained economic downturn, natural gas prices may fall, which may adversely affect our results of operations.

The unprecedented disruption in the U.S. and international credit markets in 2008 resulted in a rapid deterioration in the worldwide economy and tightening of the financial markets. The outlook for the economy in 2010 is uncertain. The current global credit and economic environment has reduced worldwide demand for energy and resulted in significantly lower natural gas prices than in earlier periods. A sustained reduction in the prices we receive for our natural gas production could have a material adverse effect on our results of operations. In addition, any worsening of conditions in the credit and equity markets could increase our financing costs and limit our financial flexibility. Any worsening of domestic and global economic conditions could adversely affect our business and results of operations.

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 governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may:

- require that we acquire permits before commencing drilling or installing equipment and infrastructure needed to market production from our properties;
- restrict the substances that can be released into the environment in connection with drilling 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, the Company could be liable for personal injury and clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. The Company could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change and greenhouse gases. 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 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 gasses" could result in increased operating costs and reduced demand for the oil and gas we produce.

On December 15, 2009, the U.S. Environmental Protection Agency *(*"EPA") officially published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Accordingly, the EPA has proposed two sets of regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and could trigger permit review for greenhouse gas emissions from certain stationary sources. In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. Also, on June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 ("ACESA"), which would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. ACESA would require a 17% reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80% reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances authorizing emissions of greenhouse gases into the atmosphere. These reductions would be expected to cause the cost of allowances to escalate significantly over time. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions and the Obama Administration has indicated its support for legislation to reduce greenhouse emissions through an emission allowance system. At the state level, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the oil and natural gas that we produce.

Significant physical effects of climatic change have the potential to damage our facilities, disrupt our production activities 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 have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low-lying areas, disruption of our production activities either because of climate-related damages to our facilities in our costs of operation potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverage in the aftermath of such effects. Significant physical effects of climate change could also have an indirect affect on our 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.

The U.S. Senate and House of Representatives are currently considering bills entitled, the "Fracturing Responsibility and Awareness of Chemicals Act," or the "FRAC Act," that would amend the federal SDWA to repeal an exemption from regulation for hydraulic fracturing. If enacted, the FRAC Act would amend the definition of "underground injection" in the SDWA to encompass hydraulic fracturing activities. If enacted, such a provision could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting, and recordkeeping obligations, and meet plugging and abandonment requirements. The FRAC Act also proposes to require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. The adoption of any future federal or state laws or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult to complete natural gas wells and increase our costs of compliance and doing business.

The adoption of derivatives legislation or regulations related to derivative contracts could have an adverse impact on our ability to hedge risks associated with our business.

Legislation has been proposed in Congress and by the Treasury Department to impose restrictions on certain transactions involving derivatives, which could affect the use of derivatives in hedging transactions. Under proposed legislation, OTC derivative dealers and other major OTC derivative market participants could be subjected to substantial supervision and regulation. The legislation generally would expand the power of the Commodity Futures Trading Commission ("CFTC"), to regulate derivative transactions related to energy commodities, including oil and natural gas, to mandate clearance of derivative contracts through registered derivative clearing organizations, and to impose conservative capital and margin requirements and strong business conduct standards on OTC derivative transactions. The CFTC has proposed regulations that would implement speculative limits on trading and positions in certain commodities. Although it is not possible at this time to predict whether or when Congress may act on derivatives legislation or the CFTC may issue new regulations, any laws or regulations that may be adopted that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

We may not be able to obtain funding on acceptable terms or at all.

Global financial markets and economic conditions have been disrupted and volatile due to a variety of factors. As a result, the cost of raising money in the debt and equity capital markets and the availability of funds from those markets is unpredictable. Although we have been able to successfully raise money in the current economic climate, we may not be successful in the future. In addition, lending counterparties under existing revolving credit facilities and other debt instruments may be unwilling or unable to meet their funding obligations. Due to these factors, we cannot be certain that new debt or equity financing will be available on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due. Moreover, without adequate funding, we may be unable to execute our growth strategy, take advantage of other business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues and results of operations.

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 may be dependent upon our ability to continue to raise significant additional financing, including debt financing or obtain other potential arrangements with industry partners in lieu of raising financing. Any arrangements that may be entered into could be expensive to us. There can be no assurance that we will be able to raise additional capital in light of factors such as the market demand for our securities, the state of financial markets for independent oil and gas companies (including the markets for debt), oil and natural gas prices and general market conditions. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" for a discussion of our capital budget.

We expect to continue using our bank credit facility to borrow funds to supplement our available cash flow. The loan commitment and aggregate amount of money we can borrow under the credit facility and from other sources is revised from time to time based on certain restrictive covenants. A change in our ability to meet the restrictive covenants might limit our ability to borrow. If this occurred, we may have to sell assets or seek substitute financing. We can make no assurances that we would be successful in selling assets or arranging substitute financing. For a description of the bank credit facility and its principal terms and conditions, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources."

Our operations may be interrupted by severe weather or drilling restrictions, particularly in the Rocky Mountain region.

Our operations are conducted primarily in the Rocky Mountain region of the United States, and will be conducted to some extent in 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.

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

Our future success depends on our ability to find, develop and acquire 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 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 fire, explosion, pipe failure, casing collapse, abnormally pressured formations, and environmental hazards such as oil spills, natural gas leaks, and discharges of toxic gases. 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 for, and 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 of exploratory or development wells, failures and losses may occur before any deposits of oil or natural gas are found. 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.

This report includes certain descriptions of our future drilling plans with respect to our prospects. 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 a prospect depends on the following factors:

- receipt of additional seismic data or reprocessing of existing data;
- material changes in oil or natural gas prices;
- the costs and availability of drilling equipment;
- success or failure of wells drilled in similar formations or which would use the same production facilities;
- availability and cost of capital;
- changes in the estimates of costs to drill or complete wells;
- the approval of partners to participate in the drilling of certain wells;
- our ability to attract other industry partners to acquire a portion of the working interest to reduce exposure to costs and drilling risks;
- decisions of our joint working interest owners; and
- regulatory requirements, including those based on the BLM's interpretation of an EIS and the results of the permitting process.

We will continue to gather data about our prospects, and it is possible that additional information may cause us to alter our drilling schedule or determine that a prospect should not be pursued at all.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying value of our oil and gas properties.

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 such 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 unweighted, 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.

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 and timing of drilling 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.

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

We acquired a portion of our acreage position in Pennsylvania through property acquisitions and acreage trades, and we may acquire additional acreage in Pennsylvania 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.

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;
- 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:

- 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;
- 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 and Pennsylvania. 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. The leases in Pennsylvania include both those from private individuals and companies, and from the Commonwealth of Pennsylvania. The leases in Pennsylvania are mostly undeveloped at this time and typically have primary lease terms of five years until establishment of production.

Green River Basin, Wyoming

As of December 31, 2009, the Company owned developed oil and natural gas leases totaling approximately 21,000 gross (10,000 net) acres in the Green River Basin of Sublette County, Wyoming which represents approximately 77% of the Company's total developed net acreage. The Company owns undeveloped oil and natural gas leases totaling approximately 91,000 gross (46,000 net) acres in the Green River Basin of Sublette County, Wyoming which represents approximately 22% of the Company's total undeveloped net acreage. The Company's acreage in the Green River Basin primarily covers the Pinedale and Jonah fields with several other undeveloped acreage blocks north and west of the Pinedale field. Lease maintenance costs in Wyoming were approximately $0.4 million for the year ended December 31, 2009. The Company currently owns 39 leases totaling 65,345 gross (36,618 net) acres currently held by production and activities ("HBP") in Wyoming. The HBP acreage includes all of the Company's leases within the productive area of the Pinedale and Jonah fields.

Exploration and development wells are identified with new criteria as of December 31, 2009. In SEC Release No. 33-8995, Modernization of Oil and Gas Reporting ("SEC Release No. 33-8995"), additional clarity is provided regarding the certainty of reserve forecasts for individual wells and the characterization of this certainty within the modernized reserve reporting framework. As a result, this clarification provides for the Company to modify its criteria for reserve reporting and classification. Accordingly, many wells that were previously characterized as exploratory simply due to prior classification as proved undeveloped reserves are more accurately characterized as developmental in nature due to the clarification of reasonable certainty under the new criteria.

Exploratory Wells. During 2009, the Company participated in the drilling of a total of 8 gross (2.80 net) productive exploratory wells on the Green River Basin properties. At December 31, 2009, there was one gross (0.27 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.

Development Wells. During 2009, the Company participated in the drilling of 155 gross (76.09 net) productive development wells on the Green River Basin properties. At year end 2009, there were 58 gross (34.78 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.

Pennsylvania

As of December 31, 2009, the Company owned developed oil and gas leases totaling approximately 6,000 gross (3,000 net) acres in the Pennsylvania portion of the Appalachian Basin which represents 23% of the Company's total developed net acreage. The Company owns undeveloped oil and gas leases totaling approximately 320,000 gross (166,000 net) acres in this area which represents 78% of the Company's total undeveloped net acreage. Lease maintenance costs in Pennsylvania were approximately $5.5 million for the year ended December 31, 2009. The Company owns approximately 6,000 gross (3,000 net) acres currently held by production or activities in Pennsylvania.

Exploratory Wells. During the year ended December 31, 2009, the Company participated in the drilling of a total of 35 gross (21.00 net) wells on the Pennsylvania properties. At December 31, 2009, there were 2 gross (1.50 net) additional exploratory wells that commenced during the year that were either still drilling or had operations suspended at a depth short of total depth and thus a determination of productive capability could not be made at year end. In its operated Marshlands area, the Company completed a 30 square mile 3-D seismic survey and began a horizontal drilling campaign in the Marcellus Shale. Also, a multi-rig, horizontal drilling program of Marcellus wells began during 2009 in the non-operated AMI area of the Company's acreage. In 2009, all activities and investments in Pennsylvania were considered exploratory for purposes of this report.

Oil and Gas Reserves

The following table sets forth the Company's quantities of proved reserves for the years ended December 31, 2009, 2008, and 2007 as estimated by independent petroleum engineers Netherland, Sewell & Associates, Inc. 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, 2009, 2008 and 2007. In accordance with Ultra's three-year planning and budgeting cycle, proved undeveloped reserves included in this table include only economic locations that are forecast to be drilled before January 1, 2013. As of December 31, 2009, proved undeveloped reserves represent 58.8% of the Company's total proved reserves. During 2009, the Company invested $741.4 million in its properties, of which, 82% was invested to convert reserves to proved developed status. We have substantially more locations than we can drill in the next three years based on our planning and budgeting process. We continually attempt to identify and schedule for drilling during the next three years the proved undeveloped locations that we believe will yield the highest return on capital invested. Additional information, changes in economics and acquisitions may cause us to alter the drilling locations included in our proved undeveloped reserves from time to time in order to permit us to develop what we identify as the highest return opportunities within the capital budget and other resources available to us.

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 & Planning is primarily responsible for overseeing the preparation of the Company's reserve estimates by our independent engineers, Netherland, Sewell & Associates, Inc. The Director has a Bachelor and Master of Science degree in Petroleum Engineering and is a licensed Professional Engineer with over 15 years 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.

All of the information regarding reserves in this annual report is derived from the report of Netherland, Sewell & Associates, Inc. The report of Netherland, Sewell & Associates, Inc. is included as an Exhibit to this annual report. The principal engineer at Netherland, Sewell & Associates, Inc. responsible for preparing our reserve estimates has a Bachelor of Science degree in Mechanical Engineering and is a licensed Professional Engineer with over 25 years of experience, including significant experience throughout the Rocky Mountain basins.

	December 31, 2009	2008	2007
Proved Developed Reserves			
Natural gas (MMcf)	1,541,813	1,412,562	1,084,224
Oil (MBbl)	11,627	11,462	8,764
Proved Undeveloped Reserves			
Natural gas (MMcf)	2,194,788	1,943,225	1,758,431
Oil (MBbl)	17,558	15,546	14,067
Total Proved Reserves (MMcfe)	3,911,711	3,517,830	2,979,644
Estimated future net cash flows, before income tax	$6,704,601	$10,040,263	$13,076,921
Standardized measure of discounted future net cash flows, before income taxes(1)	$2,887,125	$ 4,443,867	$ 5,841,194
Future income tax	$ 860,425	$ 1,426,181	$ 1,971,792
Standardized measure of discounted future net cash flows, after income tax	$2,026,700	$ 3,017,686	$ 3,869,402
Calculated average price(2)			
Gas ($/Mcf)	$ 3.04	$ 4.71	$ 6.13
Oil ($/Bbl)	$ 52.18	$ 30.10	$ 86.91

(1) Oil and condensate are converted to natural gas at the ratio of 1 Bbl of oil or condensate to 6 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) Reserves estimated by our independent engineers at December 31, 2009, reflect oil and natural gas spot prices based on the average prices during the 12-month period before the ending date of the period covered by this report determined as an unweighted, arithmetic average of the first-day-of-the-month price for each month within such period.

Reserves estimated by our independent engineers at December 31, 2008 and 2007, reflect oil and natural gas spot prices on the last day of the year.

Since January 1, 2009, no crude oil or natural gas 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.

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,		
	2009	2008	2007
	(In thousands, except per unit data)		
Production			
Natural gas (Mcf)	172,189	138,564	109,178
Oil (Bbl) — U.S.	1,320	1,122	870
Oil (Bbl) — China (See Note 12)	—	—	1,153
Total (Mcfe)	180,110	145,293	121,316
Revenues			
Natural gas sales	$601,023	$ 986,374	$509,140
Oil sales — U.S.	65,739	98,026	57,498
Oil sales — China	—	—	64,822
Total revenues	$666,762	$1,084,400	$631,460
Lease Operating Expenses			
Production costs — U.S.(a)	$ 40,679	$ 36,997	$ 23,968
Production costs — China (See Note 12)	—	—	11,419
Severance/production taxes — U.S.	66,970	119,502	63,480
Severance/production taxes — China	—	—	8,113
Gathering	45,155	37,744	27,923
Total lease operating expenses	$152,804	$ 194,243	$134,903
Realized prices			
Natural gas ($/Mcf, including realized gains (losses) on commodity derivatives)(b)	$ 4.88	$ 7.26	$ 4.66
Natural gas ($/Mcf, excluding realized gains (losses) on commodity derivatives)(b)	$ 3.49	$ 7.11	$ 4.66
Natural gas ($/Mcf, excluding financial commodity derivatives)(c)	$ 3.49	$ 7.11	$ 4.65
Oil ($/Bbl) — U.S.	$ 49.80	$ 87.40	$ 66.08
Oil ($/Bbl) — China (See Note 12)	$ —	$ —	$ 56.21
Operating costs per Mcfe — Total Consolidated			
Production costs	$ 0.23	$ 0.25	$ 0.29
Severance/production taxes	$ 0.37	$ 0.82	$ 0.59
Gathering	$ 0.25	$ 0.26	$ 0.23
Transportation charges	$ 0.32	$ 0.32	$ —
DD&A	$ 1.12	$ 1.27	$ 1.24
Interest	$ 0.21	$ 0.15	$ 0.15
Total operating costs per Mcfe	$ 2.50	$ 3.07	$ 2.50

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

(b) Effective November 3, 2008, the Company changed its method of accounting for natural gas commodity derivatives to reflect unrealized gains and losses on commodity derivative contracts in the income statement rather than on the balance sheet (See Note 7 to the Company's Consolidated Financial Statements included in this report). As a result of the de-designation on November 3, 2008, the company no longer has any derivative instruments which qualify for cash flow hedge accounting.

(c) During the first quarter of 2009, the Company converted its physical, fixed price, forward natural gas sales to physical, indexed natural gas sales combined with financial swaps whereby the Company receives the fixed price and pays the variable price. This change provides operational flexibility to curtail gas production in the event of continued declines in natural gas prices. The contracts were converted at no cost to the Company and the conversion of these contracts to derivative instruments was effective upon entering into these transactions in March 2009, with upcoming settlements for production months through December 2010. The natural gas reference prices of these commodity derivative contracts are typically referenced to natural gas index prices as published by independent third parties.

Prior to the first quarter of 2009, we sold a portion of our production pursuant to fixed price forward natural gas sales contracts (all of which were converted to physical indexed natural gas sales combined with financial swaps during the first quarter of 2009). During 2008 and 2007, we sold 32.7 MMMBtu (23%), and 6.8 MMMBtu (6%) pursuant to these contracts, respectively. The average price we received for production sold pursuant to term fixed price contracts was $6.84 and $6.20 per MMBtu in 2008 and 2007, respectively. The average spot price (as measured by the Inside FERC First of Month Index for Northwest Pipeline — Rocky Mountains) was $6.25 and $3.95 per MMBtu in 2008 and 2007, respectively. If we had sold the production we sold under the fixed price contracts at spot market prices during these periods, we may have received more or less than these prices, because the amount of production we sell could have influenced the spot market prices in the areas in which we produce and because we are able to select among several market indices when selling our production.

Productive Wells

As of December 31, 2009 the Company's total gross and net wells were as follows:

Productive Wells*	Gross Wells	Net Wells
Natural Gas and Condensate	1,270.0	599.9

* 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

As of December 31, 2009 the Company had total gross and net developed and undeveloped oil and natural gas leasehold acres in the United States as set forth below. The Company's material undeveloped properties are not subject to material acreage expiry.

The acreage and other additional information concerning the Company's oil and natural gas operations are presented in the following tables.

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Wyoming	21,000	10,000	91,000	46,000
Pennsylvania	6,000	3,000	320,000	166,000
All States	27,000	13,000	411,000	212,000

Drilling Activities

As of December 31, 2009, SEC Release No. 33-8995 provides additional clarity regarding the criteria for determining the development status of wells such that exploration and development wells are identified with new criteria. The Company implemented the new criteria as of December 31, 2009 and previous years do not reflect the updated guidelines.

For each of the three fiscal years ended December 31, 2009, 2008 and 2007 the number of gross and net wells drilled by the Company was as follows:

Wyoming — Green River Basin

	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	155.00	76.09	120.00	61.98	72.00	32.35
Dry	—	—	—	—	—	—
Total	155.00	76.09	120.00	61.98	72.00	32.35

At year end, there were 58 gross (34.78 net) additional development wells that were either drilling or had operations suspended. This includes wells in both the Pinedale and Jonah fields.

	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	8.00	2.80	108.00	59.50	79.00	43.76
Dry	—	—	—	—	—	—
Total	8.00	2.80	108.00	59.50	79.00	43.76

At year end, there was one gross (0.27 net) additional exploratory well that was either drilling or had operations suspended. This includes wells in both the Pinedale and Jonah fields.

Pennsylvania

	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	35.00	21.00	—	—	2.00	1.12
Dry	—	—	—	—	—	—
Total	35.00	21.00	—	—	2.00	1.12

At year end, there were 2 gross (1.50 net) additional exploratory wells that were either drilling or had operations suspended.

China — Bohai Bay

	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	—	—	—	—	15.00	1.34
Dry	—	—	—	—	—	—
Total	—	—	—	—	15.00	1.34
Exploratory Wells						
Productive and Successful Appraisal*	—	—	—	—	—	—
Dry	—	—	—	—	2.00	0.18
Total	—	—	—	—	2.00	0.18

* A successful appraisal well is a well that is drilled into a formation shown to be productive of oil or natural gas by an earlier well for the purpose of obtaining more information about the reservoir.

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. ***Submission of Matters to a Vote of Security Holders.***

No matters were submitted to a vote of the Company's security holders during the fourth quarter of the fiscal year ended December 31, 2009.

PART II

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

The Company's common stock trades 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 stock for the periods indicated.

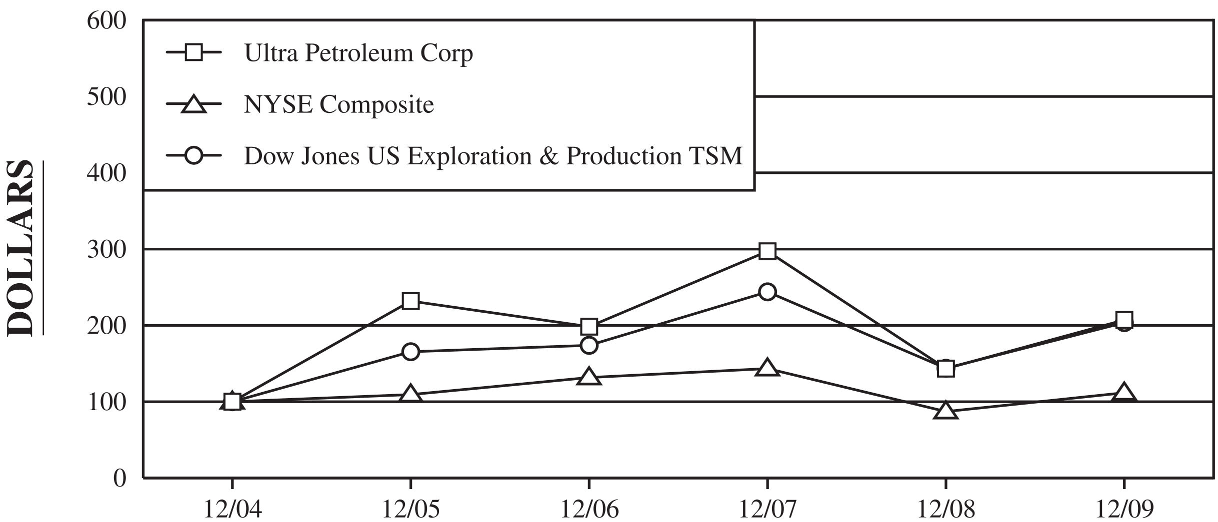
2009	High	Low
1st quarter	$42.16	$30.02
2nd quarter	$51.88	$34.89
3rd quarter	$53.28	$33.75
4th quarter	$57.21	$44.63

2008	High	Low
1st quarter	$ 81.33	$60.00
2nd quarter	$102.81	$75.35
3rd quarter	$102.81	$49.41
4th quarter	$ 56.71	$28.85

As of February 17, 2010, the last reported sales price of the common stock on the NYSE was $49.38 per share and, there were approximately 376 holders of record of the common stock.

The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the appreciation of the Company's common stock 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 stock performance. The graph compares the yearly percentage change in the cumulative total stockholder return on the Company's common stock with the cumulative total return of the NYSE Composite Index and of the Dow Jones U.S. Exploration and Production Index (formerly Dow Jones Secondary Oils Stock Index) from December 31, 2004 through December 31, 2009. This marks a successful transition from the Standard & Poor's Composite 500 Stock Index and takes into consideration the name change of the Dow Jones Wilshire Exploration and Production Index.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*
Among Ultra Petroleum Corp., The NYSE Composite Index
And The Dow Jones US Exploration & Production TSM Index



* $100 invested on 12/31/04 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

	12/04	12/05	12/06	12/07	12/08	12/09
Ultra Petroleum Corp	**100.00**	**231.87**	**198.38**	**297.11**	**143.40**	**207.19**
NYSE Composite	**100.00**	**109.36**	**131.74**	**143.42**	**87.12**	**111.76**
Dow Jones US Exploration & Production TSM	**100.00**	**165.49**	**173.90**	**243.97**	**143.87**	**203.62**

The Company has not declared or paid and does not anticipate declaring or paying any dividends on its common stock in the near future. The Company intends to retain its cash flow from operations for the future operation and development of its business.

Item 6. *Selected Financial Data.*

The selected consolidated financial information presented below for the years ended December 31, 2009, 2008, 2007, 2006 and 2005 is derived from the Consolidated Financial Statements of the Company. The earnings per share information (basic income per common share and diluted income per common share) have been updated to reflect the 2 for 1 stock split on May 10, 2005.

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Natural gas sales	$ 601,023	$ 986,374	$ 509,140	$ 470,324	$ 422,091
Oil sales	65,739	98,026	57,498	38,335	26,640
Total operating revenues	666,762	1,084,400	566,638	508,659	448,731
Expenses:					
Production expenses and taxes	152,804	194,243	115,371	92,688	78,862
Transportation charges	58,011	46,310	—	—	—
Depletion, depreciation and amortization	201,826	184,795	135,470	79,675	48,455
Write-down of proved oil and gas properties	1,037,000	—	—	—	—
General and administrative	8,871	11,230	7,543	12,259	11,405
Stock compensation	10,901	5,816	5,718	2,626	2,859
Interest expense	37,167	21,276	17,760	3,909	3,286
Total operating expenses	1,506,580	463,670	281,862	191,157	144,867
Other:					
Gain on commodity derivatives	146,517	33,216	—	—	—
Other income (expense) , net	(2,888)	418	1,087	1,941	612
Total other income (expense), net	143,629	33,634	1,087	1,941	612
(Loss) income before income taxes	(696,189)	654,364	285,863	319,443	304,476
Income tax (benefit) provision	(245,136)	240,504	105,621	122,741	107,864
Net (loss) income from continuing operations	$ (451,053)	$ 413,860	$ 180,242	$ 196,702	$ 196,612
Income from discontinued operations (including pre-tax gain on sale of $98,066 in 2007)	—	415	82,794	34,493	31,688
Net (loss) income	$ (451,053)	$ 414,275	$ 263,036	$ 231,195	$ 228,300
Basic Earnings per Share:					
(Loss) income per common share from continuing operations	$ (2.98)	$ 2.72	$ 1.19	$ 1.28	$ 1.28
Income per common share from discontinued operations	$ —	$ —	$ 0.54	$ 0.22	$ 0.21
Net (loss) income per common share — basic	$ (2.98)	$ 2.72	$ 1.73	$ 1.50	$ 1.49
Fully Diluted Earnings per Share:					
(Loss) income per common share from continuing operations	$ (2.98)	$ 2.65	$ 1.14	$ 1.22	$ 1.21
Income per common share from discontinued operations	$ —	$ —	$ 0.52	$ 0.21	$ 0.20
Net (loss) income per common share — fully diluted	$ (2.98)	$ 2.65	$ 1.66	$ 1.43	$ 1.41
Statement of Cash Flows Data:					
Net cash provided by (used in):					
Operating activities	$ 592,641	$ 840,803	$ 427,949	$ 437,333	$ 414,140
Investing activities	$ (820,611)	$ (915,319)	$ (507,070)	$ (453,882)	$(306,549)
Financing activities	$ 228,067	$ 78,041	$ 75,179	$ (12,845)	$ (80,344)
Balance Sheet Data:					
Cash and cash equivalents	$ 14,254	$ 14,157	$ 10,632	$ 14,574	$ 43,968
Working capital (deficit)	$ (137,450)	$ (149,355)	$ (67,505)	$ 55,036	$ 44,600
Oil and gas properties	$1,794,603	$2,350,526	$1,574,529	$1,006,998	$ 599,901
Total assets	$2,060,005	$2,558,162	$1,751,582	$1,258,299	$ 742,566
Total long-term debt	$ 795,000	$ 570,000	$ 290,000	$ 165,000	$ —
Other long-term obligations	$ 35,858	$ 46,206	$ 26,672	$ 25,262	$ 19,821
Deferred income taxes, net	$ 239,217	$ 503,597	$ 341,406	$ 252,808	$ 148,743
Total shareholders' equity	$ 648,197	$1,090,786	$ 857,546	$ 631,258	$ 572,910

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. Except as otherwise indicated, all amounts are expressed in U.S. dollars. We operate in one industry segment, natural gas and oil exploration and development, with one geographical segment, the United States.

The Company currently generates substantially all of its revenue, earnings and cash flow from the production and sales of natural gas and condensate from its property in southwest Wyoming. The price of natural gas is a critical factor to the Company's business and the price of natural gas has historically been volatile. Volatility could be detrimental to the Company's financial performance. The Company seeks to limit the impact of this volatility on its results by entering into fixed price forward physical delivery contracts and swap agreements for natural gas. The average price realization for the Company's natural gas during 2009 was $4.88 per Mcf, including realized gains and losses on commodity derivatives. During the quarter ended December 31, 2009, the average price realization for the Company's natural gas was $4.86 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 $3.49 per Mcf and $4.20 per Mcf for the year and quarter ended December 31, 2009, respectively. (See Note 7).

The Company has grown its natural gas and oil production significantly over the past five years and management believes it has the ability to continue growing production by drilling already identified locations on its leases in Wyoming and Pennsylvania. The Company delivered 24% production growth on an Mcfe basis during the year ended December 31, 2009 as compared to the same period in 2008.

	2009	2008	2007	2006	2005
Production — Bcfe	180.1	145.3	121.3	91.6	73.8

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. Inflation has not had a material impact on the Company's results of operations and is not expected to have a material impact on the Company's results of operations in the future.

Outlook

In 2008 and 2009, we saw significant changes in the business environment in which we operate, including severe economic uncertainty, increasing market volatility and continued tightening of credit markets. These market conditions contributed to record high commodity prices during the first half of 2008 and nearly unprecedented drops in these commodity prices in the second half of 2008 and throughout 2009.

We believe we are well positioned for the current economic environment because of our status as a low cost operator in the industry combined with our financial flexibility. In 2009, the Company established new production records while maintaining a low cost structure which contributes to the consistency of the Company's growth and returns. Although our net cash provided by operating activities was negatively affected by general economic conditions, we believe that we will continue to generate positive cash flow from operations, which, along with our available cash, will provide sufficient liquidity to allow us to return value to our shareholders.

While we continue to monitor the overall health of the credit markets, we expect to rely on our available cash, our existing credit facility and the cash we generate from our operations to meet our obligations and to fund our capital investments and operations over the next twelve months. A renewed, long-term disruption in the credit markets could make financing more expensive or unavailable, which could have a material adverse effect on our operations.

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. On January 6, 2010, the FASB issued Accounting Standards Update ("ASU"), Oil and Gas Reserve Estimation and Disclosures. The ASU amends FASB ASC Topic 932, Extractive Activities — Oil and Gas ("FASB ASC 932") to align the reserve calculation and disclosure requirements of FASB ASC 932 with the requirements in SEC Release No. 33-8995. The ASU is effective for reporting periods ending on or after December 31, 2009.

On December 31, 2008, the SEC issued SEC Release No. 33-8995 amending oil and gas reporting requirements under Rule 4-10 of Regulation S-X and Industry Guide 2 in Regulation S-K revising oil and gas reserves estimation and disclosure requirements. The new rules include changes to pricing used to estimate reserves, the ability to include non-traditional resources in reserves, the use of new technology for determining reserves and permitting disclosure of probable and possible reserves. The primary objectives of the revisions are to increase the transparency and information value of reserve disclosures and improve comparability among oil and gas companies. The rule is effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009.

Accordingly, the Company adopted the update to FASB ASC 932 as of December 31, 2009 in order to conform to the requirements in SEC Release No. 33-8995.

In accordance with our three-year planning and budgeting cycle, proved undeveloped reserves included in the current, as well as previous reserve estimates, include only economic well locations that are forecast to be drilled within a three-year period. As a result of our self-imposed three-year limit on proved undeveloped reserves inventory, we have not booked any proved undeveloped reserves beyond five years. As a result, it is the Company's opinion that the proved reserves included in this report would not be significantly different if they were filed under the previous guidelines.

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. The proved reserves estimates are prepared by Netherland, Sewell and Associates, an independent, third-party engineering firm.

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.

Our proved reserves are a function of many assumptions, all of which could deviate materially from actual results. As a result, our estimates of proved reserves could vary over time, and could vary from actual results.

Full Cost Method of Accounting. The accounting for and disclosure of oil and gas producing activities requires that we choose between GAAP alternatives. The Company uses the full cost method of accounting for its oil and natural gas operations. Under this method, separate cost centers are maintained for each country in which the Company incurs costs. All costs incurred in the acquisition, exploration and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes and overhead related to exploration and development activities) are capitalized. The sum of net capitalized costs and estimated future development costs of oil and natural gas properties for each full cost center are depleted using the units-of-production method. Changes in estimates of proved reserves, future development costs or asset retirement obligations are accounted for prospectively in our depletion calculation. The Company has historically based the fourth quarter depletion calculation on the respective year end reserve report. This methodology was utilized in computing the fourth quarter 2009 depletion expense.

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. Excluded costs, if any, are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the capitalized costs being amortized in the appropriate full cost pool.

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 result in lower DD&A expense 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 the first quarter of 2009, the Company recorded a $1.0 billion ($673.0 million net of tax) non-cash write-down of the carrying value of the Company's proved oil and gas properties as of March 31, 2009, as a result of the ceiling test limitation, which is reflected as write-down of proved oil and gas properties in the accompanying consolidated statements of operations. The March 31, 2009 ceiling test limitation was calculated prior to the adoption of SEC Release No. 33-8995 and was based on prices in effect on the last day of the reporting period, March 31, 2009, reflecting wellhead prices of $2.47 per Mcf for natural gas and $33.91 per barrel for condensate. The Company did not have any write-downs related to the full cost ceiling limitation in 2008 or 2007.

As of December 31, 2009, the ceiling limitation exceeded the carrying value of the Company's oil and natural gas properties. Estimates of standardized measure at December 31, 2009 were based on wellhead prices which averaged $3.04 per Mcf for natural gas and $52.18 per barrel for condensate. The average prices reflect the prices in effect on the first day of the month for the preceding twelve month period. A reduction in oil and natural gas prices and/or estimated quantities of oil and natural gas reserves would reduce the ceiling limitation and could result in a ceiling test write-down.

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 natural gas and condensate 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. The Company records a receivable or a liability to the extent it receives less or more than its share of the volumes and related revenue.

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. As of December 31, 2009, the Company had net deferred tax assets totaling $53.5 million which management considers is more likely than not to be realized.

Derivative Instruments and Hedging Activities. Currently, the Company largely relies on commodity derivative contracts (generally, financial swaps) to manage its exposure to commodity price risk. Additionally, and from time to time, the Company enters into physical, fixed price forward natural gas sales in order to mitigate its commodity price exposure on a portion of its natural gas production. These fixed price forward gas sales are considered normal sales in the ordinary course of business and outside the scope of FASB ASC Topic 815, Derivatives and Hedging (“FASB ASC 815”).

Effective November 3, 2008, the Company changed its method of accounting for natural gas commodity derivatives to reflect unrealized gains and losses on commodity derivative contracts in the income statement rather than on the balance sheet. The Company previously followed hedge accounting for its natural gas hedges. Under this prior accounting method, the unrealized gain or loss on qualifying cash flow hedges (calculated on a mark to market basis, net of tax) was recorded on the balance sheet in stockholders’ equity as accumulated other comprehensive income (loss). When an unrealized hedging gain or loss was realized upon contract expiration, it was reclassified into earnings through inclusion in natural gas sales revenues. The Company continues to record the fair value of its commodity derivatives as an asset or liability on the Consolidated Balance Sheets, but 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. There is no resulting effect on overall cash flow, total assets, total liabilities or total stockholders’ equity, and there is no impact on any of the financial covenants under the Company’s Senior Credit Facility, 2008 Senior Notes or 2009 Senior Notes (See Note 5).

During the first quarter of 2009, the Company converted its physical, fixed price, forward natural gas sales to physical, indexed natural gas sales combined with financial swaps whereby the Company receives the fixed price and pays the variable price. This change provides operational flexibility to curtail gas production in the event of continued declines in natural gas prices. The contracts were converted at no cost to the Company and the conversion of these contracts to derivative instruments was effective upon entering into these transactions in March 2009, with upcoming settlements for production months through December 2010.

Fair Value Measurements. The Company adopted FASB ASC Topic 820, Fair Value Measurements and Disclosures (“FASB ASC 820”), as of January 1, 2008. The implementation of these requirements was applied prospectively for our assets and liabilities that are measured at fair value on a recurring basis, primarily our commodity derivatives, with no material impact on consolidated results of operations, financial position or liquidity. For those non-financial assets and liabilities measured or disclosed at fair value on a non-recurring basis, primarily our asset retirement obligation, this respective subtopic of FASB ASC 820 was effective January 1, 2009.

Implementation of this portion of the standard did not have a material impact on consolidated results of operations, financial position or liquidity. See Note 8 for additional information.

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 utilized to measure the fair value of the Company's 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).

In consideration of counterparty credit risk, the Company assessed the possibility of whether each counterparty to the derivative would default by failing to make any contractually required payments as scheduled in the derivative instrument in determining the fair value. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions.

The fair values summarized below were determined in accordance with the requirements of FASB ASC 820 and we aligned the categories below with the Level 1, 2, and 3 fair value measurements as defined by FASB ASC 820. The balance of net unrealized gains and losses recognized for our energy-related derivative instruments at December 31, 2009 is summarized in the following table based on the inputs used to determine fair value:

	Level 1(a)	Level 2(b)	Level 3(c)	Total
Assets:				
Current derivative asset	$—	$ 4,398	$—	$ 4,398
Long-term derivative asset	$—	$ 2,554	$—	$ 2,554
Liabilities:				
Current derivative liability	$—	$35,033	$—	$35,033
Long-term derivative liability	$—	$50,542	$—	$50,542

(a) Values represent observable unadjusted quoted prices for traded instruments in active markets.

(b) Values with inputs that are observable directly or indirectly for the instrument, but do not qualify for Level 1.

(c) Values with a significant amount of inputs that are not observable for the instrument.

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, 2009, 2008 and 2007 was $10.9 million, $5.8 million and $5.7 million, respectively. See Note 6 for additional information.

Results of Operations — Year Ended December 31, 2009 vs. Year Ended December 31, 2008

During the year ended December 31, 2009, production increased on a gas equivalent basis to 180.1 Bcfe from 145.3 Bcfe for the same period in 2008 attributable to the Company's successful drilling activities during 2009. Realized natural gas prices, including realized gain and loss on commodity derivatives, decreased 33% to $4.88 per Mcf during the year ended December 31, 2009 as compared to $7.26 per Mcf for the same period in 2008. During the year ended December 31, 2009, the Company's average price for natural gas was $3.49 per Mcf, excluding realized gains and losses on commodity derivatives as compared to $7.11 per Mcf for the same period in 2008. The decrease in average natural gas prices partially offset by the increase in production contributed to a 39% decrease in revenues for the year ended December 31, 2009 to $666.8 million as compared to $1.1 billion in 2008.

Lease operating expense ("LOE") increased to $40.7 million for the year ended December 31, 2009 compared to $37.0 million during the same period in 2008 due primarily to increased well counts resulting from the Company's drilling program. On a unit of production basis, LOE costs decreased to $0.23 per Mcfe at December 31, 2009 compared to $0.25 per Mcfe at December 31, 2008 as a result of increased production volumes and a higher mix of Ultra operated production during the year ended December 31, 2009.

During the year ended December 31, 2009, production taxes were $67.0 million compared to $119.5 million during the same period in 2008, or $0.37 per Mcfe, compared to $0.82 per Mcfe. The decrease in per unit taxes is attributable to decreased sales revenues as a result of lower realized gas prices during the year ended December 31, 2009 as compared to the same period in 2008. Production taxes are calculated based on a percentage of revenue from production and were 10.0% of revenues for the year ended 2009 and 11.0% for the same period in 2008.

Gathering fees increased to $45.2 million for the year ended December 31, 2009 compared to $37.7 million during the same period in 2008 largely due to increased production volumes. On a per unit basis, gathering fees decreased to $0.25 per Mcfe for the year ended December 31, 2009 as compared to $0.26 per Mcfe for the same period in 2008.

To secure pipeline infrastructure providing sufficient capacity to transport a portion of the Company's natural gas production away from southwest Wyoming and to provide for reasonable basis differentials for its natural gas, the Company incurred firm transportation charges totaling $58.0 million for the period ended December 31, 2009 as compared to $46.3 million for the same period in 2008 in association with REX Pipeline transportation charges. On a per unit basis, transportation charges remained flat at $0.32 per Mcfe (on total company volumes) for the periods ended December 31, 2009 and 2008.

DD&A increased to $201.8 million during the period ended December 31, 2009 from $184.8 million for the same period in 2008, attributable to increased production volumes, partially offset by a lower depletion rate due mainly to a lower depletable base as a result of the ceiling test limitation during the first quarter of 2009. On a unit of production basis, DD&A decreased to $1.12 per Mcfe at December 31, 2009 from $1.27 at December 31, 2008. The Company recorded a $1.0 billion non-cash write-down of the carrying value of the Company's proved oil and gas properties at March 31, 2009 as a result of the ceiling test limitation. The write-down reduced earnings in the first quarter of 2009 and results in lower DD&A expense in future periods.

General and administrative expenses increased to $19.8 million for the period ended December 31, 2009 compared to $17.0 million for the same period in 2008. The increase in general and administrative expenses is primarily attributable to increased headcount and related compensation. On a per unit basis, general and administrative expenses decreased to $0.11 per Mcfe for the year ended December 31, 2009 as compared to $0.12 per Mcfe for the same period in 2008.

Interest expense increased to $37.2 million during the period ended December 31, 2009 compared to $21.3 million during the same period in 2008 as a result of increased borrowings during the period ended December 31, 2009. At December 31, 2009, the Company had $795.0 million in borrowings outstanding.

Other expense increased to $2.9 million as of December 31, 2009 primarily as a result of rig termination payments during the period ended December 31, 2009.

During the year ended December 31, 2009, the Company recognized $239.4 million related to realized gain on commodity derivatives as compared to $19.0 million during the year ended December 31, 2008. The realized gain or loss on commodity derivatives relates to actual amounts received or paid under the Company's derivative contracts.

During the year ended December 31, 2009, the Company recognized $92.8 million related to unrealized loss on commodity derivatives as compared to $14.2 million related to unrealized gain on commodity derivatives during the year ended December 31, 2008. The unrealized gain or loss on commodity derivatives represents the change in the fair value of these derivative instruments.

The Company recognized a loss before income taxes of $696.2 million for the year ended December 31, 2009 compared with income of $654.4 million for the same period in 2008. The decrease in earnings is primarily a result of the non-cash write-down of oil and gas properties associated with the ceiling test limitation, decreased natural gas prices partially offset by increased production and realized gains on commodity derivatives during the period ended December 31, 2009 as compared to the same period in 2008.

The income tax benefit recognized for the year ended December 31, 2009 was $245.1 million compared with an income tax provision of $240.5 million for the year ended December 31, 2008 due to a net loss during the year ended December 31, 2009 primarily as a result of the non-cash write-down of oil and gas properties associated with the ceiling test limitation.

For the year ended December 31, 2009, the Company recognized a net loss of $451.1 million or ($2.98) per diluted share as compared with net income of $414.3 million or $2.65 per diluted share for the same period in 2008. The decrease is primarily attributable to the non-cash write-down of oil and gas properties associated with the ceiling test limitation, decreased natural gas prices partially offset by increased production and realized gains on commodity derivatives during the year ended December 31, 2009 as compared to the same period in 2008.

Results of Operations — Year Ended December 31, 2008 vs. Year Ended December 31, 2007

Oil and natural gas revenues from continuing operations increased 91% to $1.1 billion for the year ended December 31, 2008 from $566.6 million for the same period in 2007. This increase was attributable to an increase in the Company's production volumes and higher prices received in 2008. During 2008, the Company's production from continuing operations increased to 138.6 Bcf of natural gas and 1.1 million barrels of condensate up from 2007 levels of 109.2 Bcf of natural gas and 870.1 thousand barrels of condensate. This 27% increase on an Mcfe basis was attributable to the Company's successful drilling activities in Wyoming during 2008 and 2007. Realized natural gas prices, including realized gains and losses on commodity derivatives, increased 56% to $7.26 per Mcf during 2008 as compared to $4.66 for the same period in 2007. During the year ended December 31, 2008, the Company's average price realization for natural gas was $7.11 per Mcf, excluding gains and losses on commodity derivatives as compared to $4.65 for the same period in 2007. During the year ended December 31, 2008, the average product prices received for condensate were $87.40 per barrel compared to $66.08 per barrel for the same period in 2007.

LOE increased to $37.0 million for the year ended December 31, 2008 compared to $24.0 million during the same period in 2007 due primarily to increased production volumes as well as increased water disposal costs on non-operated properties in Wyoming. On a unit of production basis, LOE costs increased to $0.25 per Mcfe during the year ended December 31, 2008 as compared to $0.21 per Mcfe during the same period in 2007 mainly due to costs related to non-operated properties for water disposal costs.

During the year ended December 31, 2008 production taxes were $119.5 million compared to $63.5 million during the same period in 2007, or $0.82 per Mcfe during the year ended December 31, 2008 as compared to $0.55 per Mcfe during the same period in 2007. The increase in per unit taxes is largely attributable to increased sales revenues as a result of increased production and higher realized gas prices received during the year ended December 31, 2008 as compared to the same period in 2007. Production taxes are calculated based on a percentage of revenue from production. Therefore, higher prices received increased production taxes on a per unit basis.

Gathering fees increased to $37.7 million during 2008 compared to $27.9 million during 2007 largely due to increased production volumes. On a per unit basis, gathering fees increased slightly to $0.26 per Mcfe for the year ended December 31, 2008 compared to $0.24 per Mcfe for the year ended December 31, 2007.

To secure pipeline infrastructure providing sufficient capacity to transport a portion of the Company's natural gas production away from southwest Wyoming and to mitigate volatility and provide for reasonable basis differentials for its natural gas, the Company incurred transportation demand charges totaling $46.3 million, or $0.32 per Mcfe, for the year ended December 31, 2008 in association with the REX Pipeline. The REX Pipeline became operational beginning in the first quarter of 2008.

DD&A expenses increased to $184.8 million during the year ended December 31, 2008 from $135.5 million for the same period in 2007, attributable to increased production volumes and a higher depletion rate, due to higher development costs. On a unit basis, DD&A increased to $1.27 per Mcfe for the year ended December 31, 2008 from $1.18 per Mcfe for the same period in 2007.

General and administrative expenses increased by 28% to $17.0 million during the year ended December 31, 2008 compared to $13.3 million for the same period in 2007. The increase in general and administrative expenses during 2008 is primarily attributable to increased Medicare taxes as a result of increased employee stock option exercises as well as higher compensation costs related to increased personnel during 2008 as compared to 2007. On a per unit basis, general and administrative expenses remained flat at $0.12 per Mcfe during the years ended December 31, 2008 and 2007.

Interest expense increased to $21.3 million during the year ended December 31, 2008 from $17.8 million during the same period in 2007. The increase is related to higher average outstanding debt balances during the year ended December 31, 2008 as compared to the same period in 2007. The increase in debt balances during 2008 is primarily related to the issuance of the Senior Notes on March 6, 2008 (See Note 5) as well as increased share repurchase activity in 2008 as compared to 2007.

During the year ended December 31, 2008, the Company recognized $19.0 million and $14.2 million related to realized gain on commodity derivatives and unrealized gain on commodity derivatives, respectively. These amounts relate to derivative contracts that the Company entered into during the first quarter of 2008 in order to mitigate commodity price exposure on a portion of the forecasted production which was expected to be sold on REX. Due to limited historical data correlating REX sales points and NWPL — Rockies (the basis of the contracts), the Company was unable to effectively demonstrate correlation between the derivative instrument and the forecasted transaction according to the contemporaneous documentation as set forth under the requirements of SFAS No. 133 causing the derivative contracts to no longer qualify for hedge accounting treatment. The realized gain on commodity derivatives relates to actual amounts received under these derivative contracts while the unrealized gain on commodity derivatives represents the change in the fair value of these derivative instruments.

Income before income taxes increased by 129% to $654.4 million for the year ended December 31, 2008 from $285.9 million for the same period in 2007 largely as a result of increased realized natural gas prices and increased production volumes during the year ended December 31, 2008 as compared to 2007.

The income tax provision increased 128% to $240.5 million for the year ended December 31, 2008 as compared to $105.6 million for the year ended December 31, 2007 attributable to increased pre-tax income and withholding taxes related to share repurchases.

Discontinued operations, net of tax, (which is comprised entirely of results associated with the Chinese operations) decreased to $0.4 million for the year ended December 31, 2008 from $82.8 million for the same period in 2007. The decrease is primarily related to the closing of the sale of Sino-American Energy Corporation for net proceeds of $208.0 million, which resulted in a pre-tax gain on sale of properties of $98.1 million during the quarter ended December 31, 2007. (See Note 12).

For the year ended December 31, 2008, net income increased by 57% to $414.3 million or $2.65 per diluted share as compared with $263.0 million or $1.66 per diluted share for the same period in 2007 primarily attributable to increased gas prices realized in 2008 as well as increased natural gas production during 2008.

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 generally accepted accounting principles 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, judgments and assumptions will occur as a result of future events, and, accordingly, actual results could differ from amounts estimated.

LIQUIDITY AND CAPITAL RESOURCES

During the year ended December 31, 2009, the Company relied on cash provided by operations along with borrowings under the senior credit facility and the issuance of the 2009 Senior Notes to finance its capital expenditures. The Company participated in the drilling of 259 wells in Wyoming and Pennsylvania during 2009. For the year ended December 31, 2009, net capital expenditures were $741.4 million. At December 31, 2009, the Company reported a cash position of $14.3 million compared to $14.2 million at December 31, 2008. Working capital deficit at December 31, 2009 was $137.5 million compared to a deficit of $149.4 million at December 31, 2008. At December 31, 2009, we had $260.0 million in outstanding borrowings and $240.0 million of available borrowing capacity under our credit facility. In addition, the Company had $535.0 million outstanding in senior notes (See Note 5). Other long-term obligations of $35.9 million at December 31, 2009 is comprised of items payable in more than one year, primarily related to production taxes and our asset retirement obligation.

The Company's positive cash provided by operating activities, along with availability under the senior credit facility, are projected to be sufficient to fund the Company's budgeted capital investment program for 2010, which is currently projected to be approximately $1.1 billion. Of the $1.1 billion budget, the Company plans to allocate approximately 60% to Wyoming and 40% to Pennsylvania.

On December 21, 2009, the Company announced that it had signed a purchase and sale agreement to acquire additional acreage in the Pennsylvania Marcellus Shale in order to increase the scale of its Marcellus position. On February 22, 2010, the transaction closed for $333.0 million. This transaction is incremental to the 2010 budgeted capital investment program discussed above.

Additionally, on January 28, 2010, the Company's subsidiary, Ultra Resources, Inc., agreed to issue an aggregate amount of $500.0 million of Senior Notes (the "2010 Senior Notes") pursuant to a Second Supplement to its Master Note Purchase Agreement dated March 6, 2008. Of the 2010 Senior Notes: $270.0 million of the 2010 Senior Notes were issued January 28, 2010 and $230.0 million of the 2010 Senior Notes were issued February 16, 2010. The 2010 Senior Notes rank pari passu with Ultra Resources' bank revolving credit facility and other outstanding Senior Notes. Proceeds from the 2010 Senior Notes were used to repay revolving credit facility debt, but did not reduce the borrowings available under the revolving credit facility, and for general corporate purposes, including funding the Pennsylvania Marcellus Shale acquisition that closed on February 22, 2010.

Bank indebtedness. The Company (through its subsidiary) is a party to a revolving credit facility with a syndicate of banks led by JP Morgan Chase Bank, N.A. which matures in April 2012. This agreement provides an initial loan commitment of $500.0 million and may be increased to a maximum aggregate amount of $750.0 million at the request of the Company. Each bank has the right, but not the obligation, to increase the amount of its commitment as requested by the Company. In the event the existing banks increase their commitment to an amount less than the requested commitment amount, then it would be necessary to add new financial institutions to the credit facility.

Loans under the credit facility are unsecured and bear interest, at the Company's option, based on (A) a rate per annum equal to the higher of the prime rate or the weighted average fed funds rate on overnight transactions during the preceding business day plus 50 basis points, or (B) a base Eurodollar rate, substantially equal to the LIBOR rate, plus a margin based on a grid of the Company's consolidated leverage ratio (100.0 basis points per annum as of December 31, 2009).

The facility has restrictive covenants that include the maintenance of a ratio of consolidated funded debt to EBITDAX (earnings before interest, taxes, DD&A and exploration expense) not to exceed 3½ times; and as long as the Company's debt rating is below investment grade, the maintenance of an annual ratio of the net present value of the Company's oil and gas properties to total funded debt of at least 1.75 to 1.00. At December 31, 2009, the Company was in compliance with all of its debt covenants under the credit facility. (See Note 5).

Senior Notes: On March 6, 2008, the Company's wholly-owned subsidiary, Ultra Resources, Inc. issued $300.0 million Senior Notes ("the 2008 Senior Notes") pursuant to a Master Note Purchase Agreement between the Company and the purchasers of the Notes. On March 5, 2009, the Company's wholly-owned subsidiary, Ultra Resources, Inc., issued $235.0 million Senior Notes ("the 2009 Senior Notes") pursuant to a First Supplement to the Master Note Purchase Agreement.

The Senior Notes rank pari passu with the Company's bank credit facility. Payment of the Senior Notes is guaranteed by Ultra Petroleum Corp. and UP Energy Corporation.

Proceeds from the sale of the Senior Notes were used to repay bank debt or for general corporate purposes, but did not reduce the borrowings available to the Company under the revolving credit facility. The Senior Notes are pre-payable in whole or in part at any time and are subject to representations, warranties, covenants and events of default customary for a senior note financing. At December 31, 2009, the Company was in compliance with all of its debt covenants under the Senior Notes. (See Note 5).

Operating Activities. During the year ended December 31, 2009, net cash provided by operating activities was \$592.6 million, a 30% decrease from \$840.8 million for the same period in 2008. The decrease in net cash provided by operating activities was largely attributable to the decrease in realized natural gas prices partially offset by increased production during the year ended December 31, 2009 as compared to the same period in 2008.

Investing Activities. During the year ended December 31, 2009, net cash used in investing activities was \$820.6 million as compared to \$915.3 million for the same period in 2008. The decrease in net cash used in investing activities is largely due to decreased capital expenditures associated with the Company's drilling activities in 2009 as compared to 2008 partially offset by the timing of payments associated with capital costs incurred during 2008 and paid during 2009.

Financing Activities. During the year ended December 31, 2009, net cash provided by financing activities was \$228.1 million as compared to net cash provided by investing activities of \$78.0 million for the same period in 2008. The increase in cash provided by net financing activities is primarily attributable to decreased share repurchases during 2009 as compared to 2008.

OFF BALANCE SHEET ARRANGEMENTS

The Company did not have any off-balance sheet arrangements as of December 31, 2009.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2009:

	Payments Due by period:				
	Total	2010	2011-2013	2014-2015	2016 and Beyond
	(Amounts in thousands of U.S. dollars)				
Long-term debt (See Note 5)	\$ 795,000	\$ —	\$260,000	\$100,000	\$435,000
Transportation contract (REX)	789,313	78,110	284,700	302,768	123,735
Drilling contracts	144,797	64,419	80,378	—	—
Office space lease	1,566	764	802	—	—
Total contractual obligations	\$1,730,676	\$143,293	\$625,880	\$402,768	\$558,735

Transportation contract. In December 2005, the Company agreed to become 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 for a term of 10 years commencing with initial transportation in January 2008, and the Company is obligated to pay REX certain demand charges related to its rights to hold this firm transportation capacity as an anchor shipper.

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. This additional capacity will provide the Company with the ability to move additional volumes from its producing wells in Wyoming to markets in the eastern U.S.

Drilling contracts. As of December 31, 2009, the Company had committed to drilling obligations with certain rig contractors that will continue into 2012. The drilling rigs were contracted to fulfill the 2009-2012 drilling program initiatives in Wyoming.

Office space lease. In May 2007, the Company amended its office leases in Englewood, Colorado and Houston, Texas, both of which it has committed through 2012. The Company's total remaining commitment for office leases is $1.6 million at December 31, 2009 ($0.8 million in 2010, $0.7 million in 2011 and $0.1 million in 2012).

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.

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. 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.

Commodity Derivative Contracts: During the first quarter of 2009, the Company converted its physical, fixed price, forward natural gas sales to physical, indexed natural gas sales combined with financial swaps whereby the Company receives the fixed price and pays the variable price. This change provides operational flexibility to curtail gas production in the event of continued declines in natural gas prices. The contracts were converted at no cost to the Company and the conversion of these contracts to derivative instruments was effective upon entering into these transactions in March 2009, with upcoming settlements for production months through December 2010. The natural gas reference prices of these commodity derivative contracts are typically referenced to natural gas index prices as published by independent third parties.

From time to time, the Company also utilizes fixed price forward gas sales to manage its commodity price exposure. These fixed price forward gas sales are considered normal sales in the ordinary course of business and outside the scope of FASB ASC 815.

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. The application of hedge accounting was discontinued by the Company for periods beginning on or after November 3, 2008.

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 does not impact operating cash flows on the cash flow statement.

At December 31, 2009, the Company had the following open commodity derivative contracts to manage price risk on a portion of its natural gas production whereby the Company receives the fixed price and pays the variable price. See Note 8 for the detail of the asset and liability values of the following derivatives.

Type	Point of Sale	Remaining Contract Period	Volume - MMBTU/Day	Average Price/MMBTU	Fair Value - December 31, 2009 Asset/(Liability)	
Swap	NW Rockies	Apr 2010 - Oct 2010	50,000	$5.05	$	(2,417)
Swap	NW Rockies	Calendar 2010	50,000	$4.99	$	(7,774)
Swap	NW Rockies	Calendar 2010 - 2011	160,000	$5.00	$	(72,270)
Swap	NW Rockies	Calendar 2011	10,000	$6.27	$	1,538
Swap	Northeast	Calendar 2010 - 2011	30,000	$6.38	$	2,300

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, 2009, 2008 and 2007 (refer to Note 1 for details of unrealized gains or losses included in accumulated other comprehensive income in the Consolidated Balance Sheets):

	For the Year Ended December 31,		
Natural Gas Commodity Derivatives:	**2009**	**2008**	**2007**
Realized gain on commodity derivatives(1)	$239,366	$18,991	$—
Unrealized (loss) gain on commodity derivatives(1)	(92,849)	14,225	—
Total gain on commodity derivatives	$146,517	$33,216	$—

(1) Included in gain 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. 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, 2009.

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, 2009 and 2008, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2009. 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, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, the Company has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

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, 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 26, 2010

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, 2009, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (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, 2009, 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, 2009 and 2008, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2009 of Ultra Petroleum Corp. and our report dated February 26, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 26, 2010

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2009	2008	2007
	(Amounts in thousands of U.S. dollars, except per share data)		
Revenues:			
Natural gas sales	$ 601,023	$ 986,374	$509,140
Oil sales	65,739	98,026	57,498
Total operating revenues	666,762	1,084,400	566,638
Expenses:			
Lease operating expenses	40,679	36,997	23,968
Production taxes	66,970	119,502	63,480
Gathering fees	45,155	37,744	27,923
Transportation charges	58,011	46,310	—
Depletion, depreciation and amortization	201,826	184,795	135,470
Write-down of proved oil and gas properties	1,037,000	—	—
General and administrative	19,772	17,046	13,261
Total operating expenses	1,469,413	442,394	264,102
Operating (loss) income	(802,651)	642,006	302,536
Other income (expense), net:			
Interest expense	(37,167)	(21,276)	(17,760)
Gain on commodity derivatives	146,517	33,216	—
Other (expense) income, net	(2,888)	418	1,087
Total other income (expense), net	106,462	12,358	(16,673)
(Loss) income before income tax (benefit) provision	(696,189)	654,364	285,863
Income tax (benefit) provision	(245,136)	240,504	105,621
Net (loss) income from continuing operations	(451,053)	413,860	180,242
Income from discontinued operations (including pre-tax gain on sale of $98,066 in 2007)	—	415	82,794
Net (loss) income	$ (451,053)	$ 414,275	$263,036
Basic Earnings per Share:			
(Loss) income per common share from continuing operations	$ (2.98)	$ 2.72	$ 1.19
Income per common share from discontinued operations	$ —	$ —	$ 0.54
Net (loss) income per common share — basic	$ (2.98)	$ 2.72	$ 1.73
Fully Diluted Earnings per Share:			
(Loss) income per common share from continuing operations	$ (2.98)	$ 2.65	$ 1.14
Income per common share from discontinued operations	$ —	$ —	$ 0.52
Net (loss) income per common share — fully diluted	$ (2.98)	$ 2.65	$ 1.66
Weighted average common shares outstanding — basic	151,367	152,075	151,762
Weighted average common shares outstanding — fully diluted	151,367	156,531	158,616

Approved on behalf of the Board:

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

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(Amounts in thousands of U.S. dollars, except share data)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 14,254	$ 14,157
Restricted cash	1,681	2,727
Oil and gas revenue receivable	82,326	78,139
Joint interest billing and other receivables	29,411	48,571
Derivative assets	4,398	39,939
Deferred tax assets	12,225	—
Inventory	4,498	8,522
Prepaid drilling costs and other current assets	4,948	6,163
Total current assets	153,741	198,218
Oil and gas properties, net, using the full cost method of accounting:		
Proved	1,794,603	2,294,982
Unproved	—	55,544
Property, plant and equipment	73,435	5,770
Long-term derivative assets	2,554	—
Restricted cash (See Note 14)	28,257	—
Deferred financing costs and other	7,415	3,648
Total assets	$2,060,005	$2,558,162
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 131,122	$ 163,902
Production taxes payable	60,820	61,416
Derivative liabilities	35,033	1,712
Capital cost accrual	64,216	120,543
Total current liabilities	291,191	347,573
Long-term debt	795,000	570,000
Deferred income tax liabilities	239,217	503,597
Long-term derivative liabilities	50,542	—
Other long-term obligations	35,858	46,206
Commitments and contingencies (Note 11)		
Shareholders' equity:		
Common stock — no par value; authorized — unlimited; issued and outstanding — 151,759,343 and 151,232,545, at December 31, 2009 and 2008, respectively	377,339	346,832
Treasury stock	(10,525)	(45,740)
Retained earnings	281,383	774,117
Accumulated other comprehensive income	—	15,577
Total shareholders' equity	648,197	1,090,786
Total liabilities and shareholders' equity	$2,060,005	$2,558,162

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Shares Issued and Outstanding	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Treasury Stock	Total Shareholders' Equity
Balances at December 31, 2006	151,796	$201,913	$ 429,345	$ —	$ —	$ 631,258
Stock options exercised	1,849	11,686	—	—	—	11,686
Employee stock plan grants	56	877	—	—	—	877
Shares repurchased and retired	(364)	(317)	(19,326)	—	—	(19,643)
Shares repurchased	(1,068)	—	—	—	(59,245)	(59,245)
Net share settlements	(265)	—	(18,107)	—	—	(18,107)
Fair value of employee stock plan grants	—	6,038	—	—	—	6,038
Tax benefit of stock options exercised	—	36,692	—	—	—	36,692
Comprehensive earnings:						
Net earnings	—	—	263,036	—	—	263,036
Change in derivative instruments, fair value, net of taxes	—	—	—	4,954	—	4,954
Total comprehensive earnings						267,990
Balances at December 31, 2007	152,004	$256,889	$ 654,948	$ 4,954	$ (59,245)	$ 857,546
Stock options exercised	3,595	19,086	—	—	—	19,086
Employee stock plan grants	151	997	—	—	—	997
Shares repurchased and retired	—	(1,669)	(108,741)	—	110,410	—
Shares re-issued from treasury	—	(14,885)	(135,581)	—	150,466	—
Shares repurchased	(3,661)	—	—	—	(247,371)	(247,371)
Net share settlements	(856)	(152)	(50,784)	—	—	(50,936)
Fair value of employee stock plan grants	—	7,726	—	—	—	7,726
Tax benefit of stock options exercised	—	78,840	—	—	—	78,840
Comprehensive earnings:						
Net earnings		—	414,275	—	—	414,275
Change in derivative instruments, fair value, net of taxes	—	—	—	14,273	—	14,273
Reclassification of derivative fair value into earnings, net of taxes	—	—	—	(3,650)	—	(3,650)
Total comprehensive earnings						424,898
Balances at December 31, 2008	151,233	$346,832	$ 774,117	$ 15,577	$ (45,740)	$1,090,786
Stock options exercised	666	1,430	—	—	—	1,430
Employee stock plan grants	85	—	3,397	—	—	3,397
Shares re-issued from treasury	—	(1,430)	(33,785)	—	35,215	—
Net share settlements	(225)	—	(11,293)	—	—	(11,293)
Fair value of employee stock plan grants	—	16,294	—	—	—	16,294
Tax benefit of stock options exercised	—	14,213	—	—	—	14,213
Comprehensive earnings:						
Net (loss)	—	—	(451,053)	—	—	(451,053)
Reclassification of derivative fair value into earnings, net of taxes	—	—	—	(15,577)	—	(15,577)
Total comprehensive (loss)						(466,630)
Balances at December 31, 2009	151,759	$377,339	$ 281,383	$ —	$ (10,525)	$ 648,197

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2009	2008	2007
	(Amounts in thousands of U.S. dollars)		
Cash provided by (used in):			
Operating activities:			
Net (loss) income for the period	$ (451,053)	$ 414,275	$ 263,036
Adjustments to reconcile net (loss) income to cash provided by operating activities:			
Income from discontinued operations (including pre-tax gain on sale in 2007 of $98,066)	—	(415)	(82,794)
Depletion and depreciation	201,826	184,795	135,470
Write-down of proved oil and gas properties	1,037,000	—	—
Deferred and current non-cash income taxes	(253,966)	235,031	127,802
Unrealized loss (gain) on commodity derivatives	92,849	(14,225)	—
Excess tax benefit from stock based compensation	(14,213)	(78,840)	(36,692)
Stock compensation	10,901	5,816	5,718
Other	1,023	426	177
Net changes in operating assets and liabilities:			
Restricted cash	1,046	(137)	(1,923)
Accounts receivable	14,974	9,139	(48,044)
Other current assets	(2,913)	—	—
Prepaid expenses and other	4,268	(5,543)	(273)
Other non-current assets	(2,905)	—	—
Accounts payable, production taxes and accrued liabilities	(32,773)	86,487	58,019
Other long-term obligations	(13,638)	14,833	413
Current taxes payable	215	(10,839)	8,632
Net cash provided by operating activities from continuing operations	592,641	840,803	429,541
Net cash provided by operating activities from discontinued operations	—	—	(1,592)
Net cash provided by operating activities	592,641	840,803	427,949
Investing Activities:			
Oil and gas property expenditures	(673,518)	(949,650)	(696,124)
Gathering system expenditures	(67,833)	—	—
Investing activities from discontinued operations	—	—	(14,450)
Proceeds on sale of subsidiary, net of transaction costs	—	—	208,032
Change in capital cost accrual	(56,327)	32,097	(6,422)
Restricted cash	(28,257)	—	—
Inventory	4,024	4,811	5,596
Other	1,300	(2,577)	(3,702)
Net cash used in investing activities	(820,611)	(915,319)	(507,070)
Financing activities:			
Borrowings on long-term debt	817,000	662,000	396,000
Payments on long-term debt	(827,000)	(682,000)	(271,000)
Proceeds from issuance of Senior Notes	235,000	300,000	—
Deferred financing costs	(1,283)	(1,578)	(1,204)
Repurchased shares/net share settlements	(11,293)	(298,307)	(96,995)
Excess tax benefit from stock based compensation	14,213	78,840	36,692
Proceeds from exercise of options	1,430	19,086	11,686
Net cash provided by financing activities	228,067	78,041	75,179
Increase/(decrease) in cash during the period	97	3,525	(3,942)
Cash and cash equivalents, beginning of period	14,157	10,632	14,574
Cash and cash equivalents, end of period	$ 14,254	$ 14,157	$ 10,632
SUPPLEMENTAL INFORMATION:			
Cash paid for:			
Interest	$ 30,579	$ 16,092	$ 16,218
Income taxes	$ 11,403	$ 16,322	$ 21,513

See accompanying 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 the Yukon Territory, Canada. The Company's principal business activities are in the Green River Basin of southwest Wyoming and the north-central Pennsylvania area of the Appalachian Basin.

1. SIGNIFICANT ACCOUNTING POLICIES:

(a) *Basis of presentation and principles of consolidation:* The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries UP Energy Corporation, Ultra Resources, Inc. and Sino-American Energy through the date of the sale of the China operations. 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:* We consider 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. Wyoming law requires that these funds be held in a federally insured bank in Wyoming.

Long-term restricted cash represents cash set aside in an escrow account in connection with the purchase of additional acreage in the Marcellus Shale, which closed on February 22, 2010.

(d) *Property, plant and equipment:* Capital assets are recorded at cost and depreciated using the declining-balance method based on a seven-year useful life. Gathering system expenditures are recorded at cost and depreciated using the straight-line method based on a 30 year useful life.

(e) *Oil and natural gas properties:* On January 6, 2010, the Financial Accounting Standards Board ("FASB") issued an Accounting Standards Update ("ASU"), Oil and Gas Reserve Estimation and Disclosures. The ASU amends FASB Accounting Standards Codification ("ASC") Topic 932, Extractive Activities — Oil and Gas ("FASB ASC 932") to align the reserve calculation and disclosure requirements of FASB ASC 932 with the requirements in the SEC Release No. 33-8995, Modernization of Oil and Gas Reporting Requirements ("SEC Release No. 33-8995"). The ASU is effective for reporting periods ending on or after December 31, 2009.

On December 31, 2008, the SEC issued SEC Release No. 33-8995, amending oil and gas reporting requirements under Rule 4-10 of Regulation S-X and Industry Guide 2 in Regulation S-K revising oil and gas reserves estimation and disclosure requirements. The new rules include changes to pricing used to estimate reserves, the ability to include non-traditional resources in reserves, the use of new technology for determining reserves and permitting disclosure of probable and possible reserves. The primary objectives of the revisions are to increase the transparency and information value of reserve disclosures and improve comparability among oil and gas companies. The rule is effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009.

Accordingly, the Company adopted the update to FASB ASC 932 as of December 31, 2009 in order to conform to the requirements in SEC Release No. 33-8995. The implementation of this rule did not result in material additions to the Company's proved reserves included in this report as of December 31, 2009.

The Company uses the full cost method of accounting for exploration and development activities as defined by the Securities and Exchange Commission ("SEC"). Separate cost centers are maintained for each country in which the Company incurs costs. Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. 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 proved reserves as determined by independent petroleum engineers. Oil and natural gas reserves and production are converted into equivalent units based on relative energy content. Asset retirement obligations are included in the base costs for calculating depletion. The Company has historically based the fourth quarter depletion calculation on the respective year end reserve report. This methodology was utilized in computing the fourth quarter 2009 depletion expense.

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. Excluded costs, if any, are reviewed quarterly to determine if impairment has occurred. 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 result in lower DD&A expense 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 the first quarter of 2009, the Company recorded a $1.0 billion ($673.0 million net of tax) non-cash write-down of the carrying value of the Company's proved oil and gas properties as of March 31, 2009, as a result of the ceiling test limitation, which is reflected as write-down of proved oil and gas properties in the accompanying consolidated statements of operations. The ceiling test was calculated prior to the adoption of SEC Release No. 33-8995 and was based on prices in effect on the last day of the reporting period, March 31, 2009, reflecting wellhead prices of $2.47 per Mcf for natural gas and $33.91 per barrel for condensate.

(f) *Inventories:* Materials and supplies inventories are carried at cost. Inventory costs include expenditures and other charges directly and indirectly incurred in bringing the inventory to its existing condition and location. The Company uses the weighted average method of recording its inventory. Selling expenses and general and administrative expenses are reported as period costs and excluded from inventory cost. At December 31, 2009, drilling and completion supplies inventory of $4.5 million primarily includes the cost of pipe and production equipment that will be utilized during the 2010 drilling program.

(g) *Derivative Instruments and Hedging Activities: Derivative Instruments and Hedging Activities.* Currently, the Company largely relies on commodity derivative contracts to manage its exposure to commodity price risk. Additionally, and from time to time, the Company enters into physical, fixed price forward natural gas sales in order to mitigate its commodity price exposure on a portion of its natural gas production. These fixed price forward gas sales are considered normal sales in the ordinary course of business and outside the scope of FASB ASC Topic 815, Derivatives and Hedging ("FASB ASC 815"). (See Note 7).

In March 2008, the FASB updated the requirements for disclosures about derivative instruments and hedging activities. The updated requirements are intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to increase transparency about the location and amounts of derivative instruments in an entity's financial statements; how derivative instruments and related hedged items are accounted for; and how derivative instruments and related hedged items affect financial position, financial performance, and cash flows. The Company adopted these provisions effective January 1, 2009. The adoption did not have a material impact on the Company's results of operations and financial condition.

(h) *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, we recognize 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.

(i) *Earnings per share:* Basic earnings per share is computed by dividing net earnings attributable to common stockholders by the weighted average number of common shares outstanding during each period. Diluted earnings per share is computed by adjusting the average number of common shares outstanding for the dilutive effect, if any, of common stock equivalents. The Company uses the treasury stock method to determine the dilutive effect.

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

	December 31, 2009	2008	2007
(Loss) income from continuing operations	$(451,053)	$413,860	$180,242
Income from discontinued operations	—	415	82,794
Net (loss) income	$(451,053)	$414,275	$263,036
Weighted average common shares outstanding during the period	151,367	152,075	151,762
Effect of dilutive instruments(1)	—	4,456	6,854
Weighted average common shares outstanding during the period including the effects of dilutive instruments	151,367	156,531	158,616
Basic (loss) earnings per share:			
(Loss) income per common share from continuing operations	$ (2.98)	$ 2.72	$ 1.19
Income per common share from discontinued operations	$ —	$ —	$ 0.54
Net (loss) income per common share — basic	$ (2.98)	$ 2.72	$ 1.73
Fully Diluted (loss) earnings per share:			
(Loss) income per common share from continuing operations	$ (2.98)	$ 2.65	$ 1.14
Income per common share from discontinued operations	$ —	$ —	$ 0.52
Net (loss) income per common share — fully diluted	$ (2.98)	$ 2.65	$ 1.66

(1) Due to the net loss for the year ended December 31, 2009, 2.2 million shares for options and restricted stock units were anti-dilutive and excluded from the computation of loss per share.

(j) *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.

(k) *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.

(l) *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. The implementation was applied prospectively for our assets and liabilities that are measured at fair value on a recurring basis, primarily our commodity derivatives, with no material impact on consolidated results of operations, financial position or liquidity. For those non-financial assets and liabilities measured or disclosed at fair value on a non-recurring basis, primarily our asset retirement obligation, this respective subtopic of FASB ASC 820, was effective January 1, 2009. Implementation of this portion of the standard did not have a material impact on consolidated results of operations, financial position or liquidity. See Note 8 for additional information.

(m) *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.

(n) *Revenue Recognition:* Natural gas revenues are recorded based on the entitlement method. Under the entitlement method, revenue is recorded when title passes based on the Company's net revenue interest. The Company initially records its entitled share of revenues based on estimated production volumes. Subsequently, these estimated volumes are adjusted to reflect actual volumes that are supported by third party pipeline statements or cash receipts. Since there is a ready market for natural gas, the Company sells the majority of its products immediately after production at various locations at which time title and risk of loss pass to the buyer. Gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total gas production. Any amount received in excess of the Company's share is treated as a liability. If the Company receives less than its entitled share, the underproduction is recorded as a receivable. At December 31, 2009, the Company had a net natural gas imbalance asset of $2.9 million and at December 31, 2008, the Company had a net natural gas imbalance liability of $0.3 million.

(o) *Other Comprehensive Income (Loss):* Other comprehensive income (loss) is a term used to define revenues, expenses, gains and losses that under generally accepted accounting principles impact Shareholders' Equity, excluding transactions with shareholders.

	Year Ended December 31,		
	2009	**2008**	**2007**
Net (loss) income	$(451,053)	$414,275	$263,036
Unrealized gain on derivative instruments*	(24,002)	16,368	7,633
Tax expense on unrealized gain on derivative instruments	8,425	(5,745)	(2,679)
Other comprehensive (loss) income	$(466,630)	$424,898	$267,990

* Effective November 3, 2008, the Company changed its method of accounting for natural gas commodity derivatives to reflect unrealized gains and losses on commodity derivative contracts in the income statement rather than on the balance sheet (See Note 7). The net gain or loss in accumulated other comprehensive income at

November 3, 2008 remained on the balance sheet and the respective month's gains or losses were reclassified from accumulated other comprehensive income to earnings as the counterparty settlements affected earnings (January through December 2009). As a result of the de-designation on November 3, 2008, the Company no longer has any derivative instruments which qualify for cash flow hedge accounting.

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

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. As of December 31, 2009 and 2008, the Company recorded a liability of $17.4 million and $14.1 million, respectively, to account for future obligations associated with its assets.

The following table summarizes the activities for the Company's asset retirement obligations for the years ended:

	December 31, 2009	December 31, 2008
Asset retirement obligations at beginning of period	$14,079	$ 8,298
Accretion expense	1,495	686
Liabilities incurred	3,398	3,140
Liabilities settled	(80)	(220)
Revisions of estimated liabilities	(1,520)	2,175
Asset retirement obligations at end of period	17,372	14,079
Less: current asset retirement obligations	—	—
Long-term asset retirement obligations	$17,372	$14,079

3. OIL AND GAS PROPERTIES:

	December 31, 2009	December 31, 2008
Developed Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	$ 3,544,519	$2,809,082
Less: Accumulated depletion, depreciation and amortization	(1,749,916)	(514,100)
	1,794,603	2,294,982
Unproven Properties:		
Acquisition and exploration costs not being amortized*	—	55,544
	$ 1,794,603	$2,350,526

* The Company holds interests in unproven properties in which leasehold costs and seismic costs related to these interests of $55.5 million were excluded from the amortization base at December 31, 2008. Exclusion from amortization is permitted in order to avoid distortion in the amortization per unit that could result if the cost of unevaluated properties with no proved reserves attributed to them was included in the amortization base. Effective January 1, 2009, the Company has determined that these costs are not significant enough to warrant exclusion from the amortization base and has begun amortizing the costs on a unit of production basis.

During the first quarter of 2009, the Company recorded a $1.0 billion ($673.0 million net of tax) non-cash write-down of the carrying value of the Company's proved oil and gas properties as of March 31, 2009, as a result of the ceiling test limitation, which is reflected as write-down of proved oil and gas properties in the accompanying consolidated statements of operations. The March 31, 2009 ceiling test limitation was calculated prior to the adoption of SEC Release No. 33-8995 and was based on prices in effect on the last day of the reporting period, March 31, 2009, reflecting wellhead prices of $2.47 per Mcf for natural gas and $33.91 per barrel for condensate. The Company did not have any write-downs related to the full cost ceiling limitation in 2008 or 2007.

On a unit basis, DD&A from continuing operations was $1.12 per Mcfe for the year ended December 31, 2009 and $1.27 per Mcfe for the same period in 2008.

4. PROPERTY, PLANT AND EQUIPMENT:

	December 31,			
	2009			2008
	Cost	Accumulated Depreciation	Net Book Value	Net Book Value
Gathering systems	$67,971	$ (563)	$67,408	$ —
Computer equipment	1,710	(932)	778	737
Office equipment	388	(286)	102	139
Leasehold improvements	380	(272)	108	148
Land	2,437	—	2,437	2,437
Other	4,964	(2,362)	2,602	2,309
	$77,850	$(4,415)	$73,435	$5,770

Historically, the Company's condensate production was gathered from its Wyoming well locations by tanker trucks and then shipped to other locations for injection into crude oil pipelines or other facilities. During 2009, the Company initiated service on the first two (of four proposed) central gathering facilities. These facilities are part of the Company's liquids gathering system designed to gather condensate and water from various leases and wells operated by the Company as contemplated under the Supplemental Environment Impact Statement Record of Decision. The condensate and water are transported to central points in the field where condensate can be loaded into trucks or delivered into pipelines.

In Pennsylvania, the Company and our partners are constructing gas gathering pipelines and facilities, compression facilities and pipeline delivery stations to gather production from our newly completed natural gas wells. Construction on these facilities will continue throughout 2010 allowing the Company to manage its midstream capacity to coincide with increased capacity requirements from our drilling activities. 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 facilities of this type will not be required in the future to accommodate the Company's production.

5. LONG-TERM LIABILITIES:

	December 31, 2009	December 31, 2008
Bank indebtedness	$260,000	$270,000
Senior notes:		
5.45% Notes due 2015	100,000	100,000
5.92% Notes due 2018	200,000	200,000
7.31% Notes due 2016	62,000	—
7.77% Notes due 2019	173,000	—
Other long-term obligations	35,858	46,206
	$830,858	$616,206

Aggregate maturities of debt at December 31, 2009:

2010	2011-2013	2014-2015	2016 and Beyond	Total
$—	$260,000	$100,000	$435,000	$795,000

Bank indebtedness: The Company (through its subsidiary) is a party to a revolving credit facility with a syndicate of banks led by JP Morgan Chase Bank, N.A. which matures in April 2012. This agreement provides an initial loan commitment of $500.0 million and may be increased to a maximum aggregate amount of $750.0 million at the request of the Company. Each bank has the right, but not the obligation, to increase the amount of its commitment as requested by the Company. In the event the existing banks increase their commitment to an amount less than the requested commitment amount, then it would be necessary to add new financial institutions to the credit facility.

Loans under the credit facility are unsecured and bear interest, at the Company's option, based on (A) a rate per annum equal to the higher of the prime rate or the weighted average fed funds rate on overnight transactions during the preceding business day plus 50 basis points, or (B) a base Eurodollar rate, substantially equal to the LIBOR rate, plus a margin based on a grid of our consolidated leverage ratio (100.0 basis points per annum as of December 31, 2009).

At December 31, 2009, the Company had $260.0 million in outstanding borrowings and $240.0 million of available borrowing capacity under the credit facility.

The facility has restrictive covenants that include the maintenance of a ratio of consolidated funded debt to EBITDAX (earnings before interest, taxes, DD&A and exploration expense) not to exceed 3½ times; and as long as the Company's debt rating is below investment grade, the maintenance of an annual ratio of the net present value of the Company's oil and gas properties to total funded debt of at least 1.75 to 1.00. At December 31, 2009, the Company was in compliance with all of its debt covenants under the credit facility.

Senior Notes: On March 6, 2008, the Company's wholly-owned subsidiary, Ultra Resources, Inc. issued $300.0 million Senior Notes ("the 2008 Senior Notes") pursuant to a Master Note Purchase Agreement between the Company and the purchasers of the Notes. On March 5, 2009, the Company's wholly-owned subsidiary, Ultra Resources, Inc., issued $235.0 million Senior Notes ("the 2009 Senior Notes") pursuant to a First Supplement to the Master Note Purchase Agreement.

The Senior Notes rank pari passu with the Company's bank credit facility. Payment of the Senior Notes is guaranteed by Ultra Petroleum Corp. and UP Energy Corporation.

Proceeds from the sale of the Senior Notes were used to repay bank debt or for general corporate purposes, but did not reduce the borrowings available to the Company under the revolving credit facility. The Senior Notes are pre-payable in whole or in part at any time and are subject to representations, warranties, covenants and events of default customary for a senior note financing. At December 31, 2009, the Company was in compliance with all of its debt covenants under the Senior Notes.

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 three share based compensation plans: the 2005 Stock Incentive Plan (the "2005 Plan"); the 2000 Stock Incentive Plan (the "2000 Plan"); and the 1998 Stock Option Plan (the "1998 Plan"). Each of the plans is administered by the Compensation Committee of the Board of Directors (the "Committee"). The share based compensation plans are an important component of the total compensation package offered to the Company's key service providers, and they reflect 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 purpose of the 2005 Plan is to foster and promote the long-term financial success of the Company and to increase shareholder value by attracting, motivating and retaining key employees, consultants, and outside directors, and providing such participants with a program for obtaining an ownership interest in the Company that links and aligns their personal interests with those of the Company's shareholders, and thus, enabling such participants to share in the long-term growth and success of the Company. To accomplish these goals, the 2005 Plan permits the granting of incentive stock options, non-statutory stock options, stock appreciation rights, restricted stock, and other stock-based awards, some of which may require the satisfaction of performance-based criteria in order to be payable to participants. Under the 2005 Plan, the aggregate number of common shares issuable to any one person pursuant to an award cannot exceed 5% of the number of common shares outstanding at the time of the award. In addition, no participant may receive during any calendar year, awards covering an aggregate of more than 2.0 million common shares, or a cash payout with respect to any awards in excess of $5.0 million. The Committee determines the terms and conditions of the awards, including, any vesting requirements and vesting restrictions or 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.

The 2000 Plan was adopted by the Company's Board of Directors on May 1, 2000 and approved by the Company's shareholders on June 6, 2000. The 2000 Plan was established for the purposes of associating the interests of the management of the Company and its subsidiaries and affiliates closely with the Company's shareholders to generate an increased incentive to contribute to the Company's future success and prosperity; maintaining competitive compensation levels thereby attracting and retaining highly competent and talented outside directors, employees, and consultants; and providing an incentive to such management for continuous employment with the Company. The 2000 Plan operates in a very similar manner to the 2005 Plan and permits the granting of incentive stock options, non-statutory stock options, stock appreciation rights, and restricted stock. Under the 2000 Plan, the aggregate number of common shares issuable to any one person pursuant to such award cannot exceed 5% of the number of common shares outstanding at the time of the award. In addition, no participant may receive during any fiscal year of the Company, awards covering an aggregate of more than 500,000 common shares. The Committee determines the terms and conditions of the awards, including, any vesting requirements and vesting restrictions or forfeitures that may occur. The Committee may continue to grant awards under the 2000 Plan until April 30, 2010, unless terminated sooner by the Board of Directors.

The 1998 Plan was adopted by the Company's Board of Directors on October 28, 1998 and approved by the Company's shareholders on December 3, 1998. Similar to the 2000 Plan and 2005 Plan, the 1998 Plan was established as a means to attract, retain, and motivate service providers of the Company by providing them with an opportunity to acquire an increased proprietary interest in the Company through the granting of stock options. The 1998 Plan permits the granting of non-statutory stock options. Under the 1998 Plan, the aggregate number of common shares issuable to any one person pursuant to an award under the 1998 Plan, together with all other outstanding stock options granted to such person, cannot exceed 5% of the number of common shares outstanding. The Committee determines the terms and conditions of the awards, including, any vesting requirements and vesting restrictions or forfeitures that may occur. The 1998 Plan remains effective and the Company may continue to make stock option grants under the plan.

Valuation and Expense Information

	Year Ended December 31,		
	2009	**2008**	**2007**
Total cost of share-based payment plans	$18,872	$10,355	$9,581
Amounts capitalized in fixed assets	$ 7,971	$ 4,539	$3,863
Amounts charged against income, before income tax benefit	$10,901	$ 5,816	$5,718
Amount of related income tax benefit recognized in income	$ 3,826	$ 2,041	$2,007

The fair value of each share option award is estimated on the date of grant using a Black-Scholes pricing model. The Company's employee stock options have various restrictions including vesting provisions and restrictions on transfers and hedging, among others, and are often exercised prior to their contractual maturity. Expected volatilities used in the fair value estimates are based on historical volatility of the Company's stock. The Company uses historical data to estimate share option exercises, expected term and employee departure behavior used in the Black-Scholes pricing model. Groups of employees (executives and non-executives) that have similar historical behavior are considered separately for purposes of determining the expected term used to estimate fair value. The assumptions utilized result from differing pre- and post-vesting behaviors among executive and non-executive groups. The risk-free rate for periods within the contractual term of the share option is based on the U.S. Treasury yield curve in effect at the time of grant. There were no stock options granted during the year ended December 31, 2009.

Securities Authorized for Issuance Under Equity Compensation Plans

As of December 31, 2009, the Company had the following securities issuable pursuant to outstanding award agreements or reserved for issuance under the Company's previously approved stock incentive plans. Upon exercise, shares issued will be newly issued shares or shares issued from treasury.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options	Weighted Average Exercise Price of Outstanding Options	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in the First Column)
Equity compensation plans approved by security holders	3,504	$27.67	10,004
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	3,504	$27.67	10,004

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, 2009:

	Number of Options	Weighted Average Exercise Price (US$)
Balance, December 31, 2006	9,083	$ 0.25 to $67.73
Granted	436	$45.95 to $65.94
Forfeited	(81)	$47.19 to $63.05
Exercised	(1,849)	$ 0.25 to $67.73
Balance, December 31, 2007	7,589	$ 0.25 to $67.73
Granted	299	$51.14 to $98.87
Forfeited	(80)	$51.60 to $85.05
Exercised	(3,595)	$ 0.25 to $67.73
Balance, December 31, 2008	4,213	$ 0.25 to $98.87
Forfeited	(43)	$51.60 to $78.55
Exercised	(666)	$ 0.25 to $33.57
Balance, December 31, 2009	3,504	$ 1.49 to $98.87

The following tables summarize information about the stock options outstanding at December 31, 2009:

	Options Outstanding			
Range of Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Aggregate Intrinsic Value
\$ 1.49 - \$ 2.61	542	1.07	\$ 1.58	\$26,169
\$ 3.91 - \$ 4.83	592	2.86	\$ 4.63	\$26,775
\$11.68 - \$19.18	599	4.20	\$13.49	\$21,784
\$25.08 - \$55.58	882	5.52	\$36.73	\$11,889
\$46.05 - \$65.04	240	6.48	\$57.88	\$ 76
\$45.95 - \$65.94	421	7.28	\$53.98	\$ 94
\$51.14 - \$98.87	228	8.37	\$71.20	\$ —

	Options Exercisable			
Range of Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Aggregate Intrinsic Value
\$ 1.49 - \$ 2.61	542	1.07	\$ 1.58	\$26,169
\$ 3.91 - \$ 4.83	592	2.86	\$ 4.63	\$26,775
\$11.68 - \$19.18	599	4.20	\$13.49	\$21,784
\$25.08 - \$58.71	882	5.52	\$36.73	\$11,889
\$46.05 - \$65.04	240	6.48	\$57.88	\$ 76
\$45.95 - \$65.94	—	—	\$ —	\$ —
\$51.14 - \$98.87	—	—	\$ —	\$ —

The aggregate intrinsic value in the preceding tables represents the total pre-tax intrinsic value, based on the Company's closing stock price of \$49.86 on December 31, 2009, which would have been received by the option holders had all option holders exercised their options as of that date. The total number of in-the-money options exercisable as of December 31, 2009 was 2.5 million options.

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

	2009	2008	2007
Share options granted	\$ —	\$30.94	\$23.85
Non-vested share options at beginning of year	\$26.18	\$23.93	\$23.65
Non-vested share options at end of year	\$26.28	\$26.18	\$23.93
Options vested during the year	\$25.07	\$ —	\$22.79
Options forfeited during the year	\$29.57	\$27.35	\$22.25

The fair value of stock options that vested during the year ended December 31, 2009 and 2007 was \$3.9 and \$2.8 million, respectively. There were no stock options that vested during the year ended December 31, 2008. The total intrinsic value of stock options exercised during the years ended December 31, 2009, 2008 and 2007 was \$33.2 million, \$224.6 million and \$104.5 million, respectively.

At December 31, 2009, there was \$3.7 million of total unrecognized compensation cost related to non-vested, employee stock options granted under the Stock Incentive Plans. That cost is expected to be recognized over a weighted average period of 0.7 years.

PERFORMANCE SHARE PLANS:

Long Term Incentive Plans. Each year since 2005, the Company has adopted 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. For 2007 and 2008, each LTIP has two components: an "LTIP Stock Option Award" and an "LTIP Common Stock Award." In 2009, the Compensation Committee (the "Committee") approved an award consisting only of performance-based restricted stock units to be awarded to each participant.

Under each LTIP, the Committee establishes a percentage of base salary for each participant which is multiplied by the participant's base salary to derive a Long Term Incentive Value. The LTIP Common Stock Award in 2007 and 2008 and the 2009 LTIP award of restricted stock units are performance-based and are measured over a three year performance period. For each LTIP award, the Committee establishes performance measures at the beginning of each performance period, and each participant is assigned threshold and maximum award levels in the event that actual performance is below or above target levels. For the 2007, 2008 and 2009 LTIP awards, the Committee established the following performance measures: return on equity, reserve replacement ratio, and production growth.

For the year ended December 31, 2009, the Company recognized $5.8 million in pre-tax compensation expense related to the 2007 LTIP Common Stock Award, 2008 LTIP Common Stock Award and 2009 LTIP award of restricted stock units. For the year ended December 31, 2008, the Company recognized $3.6 million in pre-tax compensation expense related to the 2006, 2007, and 2008 LTIP Common Stock Awards. The amounts recognized during the year ended December 31, 2009 assumes that maximum performance objectives are attained. If the Company ultimately attains these performance objectives, the associated total compensation, estimated at December 31, 2009, for each of the three year performance periods is expected to be approximately $4.1 million, $4.0 million, and $10.2 million related to the 2007 LTIP Common Stock Award, 2008 LTIP Common Stock Award and 2009 LTIP award of restricted stock units, respectively. Additional awards of restricted stock units were granted to eligible employees during 2009 with estimated total compensation of $10.0 million over the three year performance period assuming that maximum performance objectives are attained. The 2006 LTIP Common Stock Award was paid in shares of the Company's stock to employees during the first quarter of 2009 and totaled $2.7 million.

Best in Class Program. In May 2008, the Company established the 2008 Best in Class Program for all permanent, full-time employees. Under the 2008 Best in Class Program, participants are eligible to receive a number of shares of the Company's common stock based on the performance of the Company. As with the LTIP, the 2008 Best in Class Program is measured over a three year performance period. The 2008 Best in Class Program recognizes and financially rewards the collective efforts of all of the Company's employees in achieving sustained industry leading performance and the enhancement of shareholder value. Under the 2008 Best in Class Program, on January 1, 2008 or the employment date if subsequent to January 1, 2008, eligible employees received a contingent award of stock units equal to $60,000 worth of the Company's common stock based on the average high and low share price on the first day of the performance period. Employees joining the Company after January 1, 2008 participate on a pro-rata basis based on their length of employment during the performance period.

The number of contingent units that will become payable and vest upon distribution is based on the Company's performance relative to the industry during a three year performance period beginning January 1, 2008, and ending December 31, 2010, and are set at threshold (50%), target (100%), and maximum (150%) levels. For each vested unit, the participant will receive one share of common stock. The participant must be employed on the date the awards are distributed in order to receive the award.

For the year ended December 31, 2009, the Company recognized $0.9 million in pre-tax compensation expense related to the 2008 Best in Class Program. For the year ended December 31, 2008 the Company recognized $1.2 million in pre-tax compensation expense related to the 2008 Best in Class Program. The amount recognized for the year ended December 31, 2009 and 2008 assumes that target performance levels are achieved. If the Company ultimately attains the target performance level, the associated total compensation related to the 2008 Best in Class Program is estimated at $4.4 million as of December 31, 2009.

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.

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.

Commodity Derivative Contracts: During the first quarter of 2009, the Company converted its physical, fixed price, forward natural gas sales to physical, indexed natural gas sales combined with financial swaps whereby the Company receives the fixed price and pays the variable price. This change provides operational flexibility to curtail gas production in the event of continued declines in natural gas prices. The contracts were converted at no cost to the Company and the conversion of these contracts to derivative instruments was effective upon entering into these transactions in March 2009, with upcoming settlements for production months through December 2010. The natural gas reference prices of these commodity derivative contracts are typically referenced to natural gas index prices as published by independent third parties.

From time to time, the Company also utilizes fixed price forward gas sales to manage its commodity price exposure. These fixed price forward gas sales are considered normal sales in the ordinary course of business and outside the scope of FASB ASC 815, Derivatives and Hedging.

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. The application of hedge accounting was discontinued by the Company for periods beginning on or after November 3, 2008.

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 does not impact operating cash flows on the cash flow statement.

At December 31, 2009, the Company had the following open commodity derivative contracts to manage price risk on a portion of its natural gas production whereby the Company receives the fixed price and pays the variable price. See Note 8 for the detail of the asset and liability values of the following derivatives.

Type	Point of Sale	Remaining Contract Period	Volume - MMBTU/Day	Average Price/MMBTU	Fair Value - December 31, 2009
					Asset/ (Liability)
Swap	NW Rockies	Apr 2010 - Oct 2010	50,000	$5.05	$ (2,417)
Swap	NW Rockies	Calendar 2010	50,000	$4.99	$ (7,774)
Swap	NW Rockies	Calendar 2010 - 2011	160,000	$5.00	$(72,270)
Swap	NW Rockies	Calendar 2011	10,000	$6.27	$ 1,538
Swap	Northeast	Calendar 2010 - 2011	30,000	$6.38	$ 2,300

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, 2009, 2008 and 2007 (refer to Note 1 for details of unrealized gains or losses included in accumulated other comprehensive income in the Consolidated Balance Sheets):

	For the Year Ended December 31,		
Natural Gas Commodity Derivatives:	**2009**	**2008**	**2007**
Realized gain on commodity derivatives(1)	$239,366	$18,991	$—
Unrealized (loss) gain on commodity derivatives(1)	(92,849)	14,225	—
Total gain on commodity derivatives	$146,517	$33,216	$—

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

8. FAIR VALUE MEASUREMENTS:

As required by the Fair Value Measurements and Disclosure Topic of the FASB Accounting Standards Codification, we define 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 utilized to measure the fair value of the Company's 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).

The following table presents for each hierarchy level our assets and liabilities, including both current and non-current portions, measured at fair value on a recurring basis, as of December 31, 2009. The company has no derivative instruments which qualify for cash flow hedge accounting.

	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Current derivative asset	$—	$ 4,398	$—	$ 4,398
Long-term derivative asset	$—	$ 2,554	$—	$ 2,554
Liabilities:				
Current derivative liability	$—	$35,033	$—	$35,033
Long-term derivative liability	$—	$50,542	$—	$50,542

In consideration of counterparty credit risk, the Company assessed the possibility of whether each counterparty to the derivative would default by failing to make any contractually required payments as scheduled in the derivative instrument in determining the fair value. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions.

For those non-financial assets and liabilities measured or disclosed at fair value on a non-recurring basis, primarily our asset retirement obligation, this respective subtopic of FASB ASC 820 was effective January 1, 2009. Implementation of this portion of the standard did not have a material impact on consolidated results of operations, financial position or liquidity.

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 sheet 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 debt our fixed rate debt. 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.

In April 2009, the FASB updated the requirements for interim disclosures about fair value of financial instruments requiring an entity to provide disclosures about fair value of financial instruments in interim financial information. The Company is required to include disclosures about the fair value of its financial instruments whenever it issues financial information for interim reporting periods. In addition, the Company is required to disclose in the body or in the accompanying notes of its summarized financial information for interim reporting periods and in its financial statements for annual reporting periods, the fair value of all financial instruments for which it is practicable to estimate that value, whether recognized or not recognized in the statement of financial position. This updated requirement for interim disclosures about fair value of financial instruments is effective for periods ending after June 15, 2009 and its adoption had no impact on the Company's results of operations and financial condition but requires additional disclosures about the fair value of financial instruments in the financial statements.

	December 31, 2009		December 31, 2008	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-Term Debt:				
5.45% Notes due 2015	$100,000	$108,128	$100,000	$ 93,836
5.92% Notes due 2018	200,000	212,946	200,000	180,729
7.31% Notes due 2016	62,000	72,684	—	—
7.77% Notes due 2019	173,000	205,609	—	—
Credit Facility	260,000	260,000	270,000	270,000
	$795,000	$859,367	$570,000	$544,565

9. INCOME TAXES:

(Loss) income from continuing operations before income taxes is as follows:

	Year Ended December 31,		
	2009	2008	2007
United States	$(696,096)	$654,464	$286,045
Foreign	(93)	(100)	(182)
Total	$(696,189)	$654,364	$285,863

The consolidated income tax provision is comprised of the following:

	Year Ended December 31,		
	2009	2008	2007
Current:			
U.S. federal & state	$ 23,043	$ 84,313	$ 14,511
Deferred:			
U.S. federal & state	(268,179)	156,191	91,110
Total income tax(benefit) provision	$(245,136)	$240,504	$105,621

	Year Ended December 31,		
	2009	2008	2007
Income tax (benefit) provision computed at the U.S. statutory rate	$(243,666)	$229,028	$100,052
State income tax provision net of federal benefit	(698)	650	423
Withholding tax on share repurchase transactions	—	5,409	1,068
Foreign tax credit valuation allowance	—	1,692	—
Other, net	(772)	3,725	4,078
	$(245,136)	$240,504	$105,621

During 2008 and 2007, the Company incurred U.S. withholding taxes of $5.4 million, and $1.1 million, respectively, in connection with the repurchase of shares of its common stock.

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

	Year Ended December 31,	
	2009	2008
Deferred tax assets — current:		
Derivative instruments, net	$ 10,753	$ —
Other	1,472	—
Net deferred tax assets — current	$ 12,225	$ —
Deferred tax assets — non-current:		
U.S. federal tax credit carryforwards	15,162	21,263
Canadian net operating loss carryforwards	514	497
Derivative instruments, net	16,844	—
Incentive compensation/other, net	10,930	7,866
	43,450	29,626
Valuation allowance — Foreign Tax Credit (FTC)	(1,692)	(1,692)
Valuation allowance (Canadian Net Operating Loss (NOL))	(514)	(497)
Net deferred tax assets — non-current	$ 41,244	$ 27,437

	Year Ended December 31,	
	2009	2008
Deferred tax liabilities — non-current:		
Property and equipment	(279,441)	(517,616)
Derivative instruments	—	(13,418)
Other	(1,020)	—
Net non-current tax liabilities	$(280,461)	$(531,034)
Net non-current tax liability	$(239,217)	$(503,597)

During 2009, 2008 and 2007, the Company realized tax benefits of $14.2 million $78.8 million, and $36.7 million, respectively, attributable to tax deductions associated with the exercise of stock options. These benefits reduce the amount of the Company's U.S. federal and state cash tax payments and are recorded as a reduction of current taxes payable (though not a reduction of the current provision) and as an increase in shareholders' equity.

The income tax provision for 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:

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, projected future taxable income and available tax planning strategies.

The Company did not have any unrecognized tax benefits and there was no effect on our financial condition or results of operations as a result of implementing the standard related to accounting for uncertain tax positions. The amount of unrecognized tax benefits did not change as of December 31, 2009.

It is expected that the amount of unrecognized tax benefits may change in the next twelve months; however Ultra does not expect the change to have a significant impact on the results of operations or the financial position of the Company. The Company currently has no unrecognized tax benefits that if recognized would affect the effective tax rate.

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 Canada. With certain exceptions, the Company is no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years before 2001.

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

As of December 31, 2009, the Company had approximately $13.0 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. In addition, as of December 31, 2009, the Company has $2.1 million of foreign tax credit carryforwards, none of which expire prior to 2017. However, with the 2007 sale of Sino American Energy, the Company no longer has foreign source income for which to utilize its foreign tax credit carryforwards. Therefore, a valuation allowance has been placed on the remaining foreign tax credit carryforwards.

The Company has Canadian net operating loss carryforwards of approximately $2.7 million and $2.3 million as of December 31, 2009 and December 31, 2008, respectively. The benefit of the Canadian loss carryforwards can only be utilized to the extent the Company generates future taxable income in Canada. If not utilized, the Canadian loss carryforward will expire between 2010 and 2029.

Since the Company currently has no income producing operations in Canada, management estimates that it is more likely than not that the Canadian loss carryforwards will not be utilized. A valuation allowance has been recorded at December 31, 2009 and December 31, 2008 attributable to this deferred tax asset.

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.

The Company periodically uses derivative instruments designated as cash flow hedges for tax purposes as a method of managing its exposure to commodity price fluctuations. To the extent these hedges are effective, changes in the fair value of these derivative instruments are recorded in Other Comprehensive Income, net of income tax. To the extent these hedges are ineffective, they are marked to market with gains and losses recorded in the statement of operations. At December 31, 2008, the Company had open derivative contracts; and, therefore, recorded a deferred tax liability of $8.4 million, attributable to unrecognized gains on derivative instruments which are allocated directly to Other Comprehensive Income. At December 31, 2009 and 2008, the Company also recorded a deferred tax asset of $27.6 million and a deferred tax liability of $5.0 million, respectively, attributable to the unrealized gains recorded in the statement of operations.

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 up to 100% of their compensation, subject to certain limitations. The Company matches the employee contributions up to 5% of employee compensation along with a profit sharing contribution of 8%. The expense associated with the Company's contribution was $1.1 million, $0.9 million and $0.9 million for the years ended December 31, 2009, 2008 and 2007, respectively.

11. COMMITMENTS AND CONTINGENCIES:

Transportation contract. In December 2005, the Company agreed to become 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 for a term of 10 years commencing with initial transportation in January 2008, and the Company is obligated to pay REX certain demand charges related to its rights to hold this firm transportation capacity as an anchor shipper. 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. This additional capacity will provide the Company with the ability to move additional volumes from its producing wells in Wyoming to markets in the eastern U.S. The Company currently projects that demand charges related to the remaining term of the contract will total approximately $789.3 million.

There have been and will continue to be, numerous other proposed pipeline projects to transport growing Rockies and Wyoming natural gas production to a variety of geographically diverse markets in different parts of North America. Many such proposals have been presented to the Company in recent months, which, if constructed, would provide the Company with additional outlets and market access for its natural gas production from southwest Wyoming. The Company continuously evaluates such proposals and may make additional commitments to one or more such pipeline projects in the future.

Drilling contracts. As of December 31, 2009, the Company had committed to drilling obligations with certain rig contractors totaling $144.8 million ($64.4 million due in 2010, $80.4 million due in one to three years). The commitments expire in 2012 and were entered into to fulfill the Company's drilling program initiatives in Wyoming.

Office space lease. In May 2007, the Company amended its office leases in Englewood, Colorado and Houston, Texas, both of which it has committed through 2012. The Company's total remaining commitment for office leases is $1.6 million at December 31, 2009 ($0.8 million in 2010, $0.7 million in 2011 and $0.1 million in 2012).

During the years ended December 31, 2009, 2008 and 2007, the Company recognized expense associated with its office leases in the amount of $0.9 million, $0.7 million, and $0.6 million, respectively.

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. DISCONTINUED OPERATIONS:

During the third quarter of 2007, we made the decision to dispose of Sino-American Energy Corporation ("Sino-American"), which owned our Bohai Bay assets in China, in order to focus on our legacy asset in the Pinedale Field in southwest Wyoming. The reserve volumes sold represent all of Ultra's international assets and, previously, were the only results included in our foreign operating segment.

The Company accounted for its Sino-American operations as discontinued operations and reclassified prior period financial statements to exclude these businesses from continuing operations. A summary of financial information related to the Company's discontinued operations is as follows:

	For the Year Ended December 31,		
	2009	2008	2007
Operating revenues	$—	$ —	$ 64,822
Gain on sale of subsidiary	—	640	98,066
Lease operating expenses	—	—	11,419
Severance taxes	—	—	8,113
Depletion, depreciation and amortization	—	—	14,981
General and administrative expenses	—	—	99
Income before income tax provision	—	640	128,276
Income tax provision	—	225	45,482
Income from discontinued operations, net of tax	$—	$415	$ 82,794

13. CREDIT RISK:

The Company's revenues are derived principally from uncollateralized sales to customers in the natural gas and oil industry. The concentration of credit risk in a single industry affects the Company's overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions. The Company performs a credit analysis of customers prior to making any sales to new customers or increasing extension of credit for existing customers. Based upon this credit analysis, the Company may require a standby letter of credit or a financial guarantee.

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. Concentrations of credit risk with respect to receivables are limited due to its large number of customers and their dispersion across geographic areas.

A significant counterparty is defined as one that individually accounts for 10% or more of the Company's total revenues during the year. In 2009, the Company had three significant counterparties associated with sales of its natural gas production and commodity derivatives contracts. Sales and settlements of derivative contracts to Sempra Energy Trading Corp., J Aron & Company and JP Morgan Chase Bank, N.A. were $144.9 million, $101.3 million, and $97.1 million, respectively, which accounted for 16.2%, 11.3% and 10.8% of the Company's total 2009 revenues (including realized gains on commodity derivatives), respectively. At December 31, 2009, the Company had outstanding receivables (which were received in full in January 2010) from Sempra Energy Trading Corp., J Aron & Company and JP Morgan Chase Bank, N.A. totaling $19.7 million.

14. SUBSEQUENT EVENTS:

FASB ASC Topic 855, Subsequent Events ("FASB ASC 855"), sets forth principles and requirements to be applied to the accounting for and disclosure of subsequent events. FASB ASC 855 sets forth the period after the balance sheet date during which management shall evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, the circumstances under which events or transactions occurring after the balance sheet date shall be recognized in the financial statements and the required disclosures about events or transactions that occurred after the balance sheet date. The FASB issued ASU No. 2010-09, Subsequent Events (FASB ASC 855), Amendments to Certain Recognition and Disclosure Requirement*s,* on February 24, 2010, in an effort to remove some contradictions between the requirements of U.S. GAAP and the SEC's filing rules. The amendments remove the requirement that public companies disclose the date of their financial statements in both issued and revised financial statements. The Company has evaluated the period subsequent to December 31, 2009 for events that did not exist at the balance sheet date but arose after that date and determined that the subsequent events described below should be disclosed in order to keep the financial statements from being misleading.

On December 21, 2009, the Company announced that it had signed a purchase and sale agreement, subject to due diligence, to acquire additional acreage in the Pennsylvania Marcellus Shale in order to increase the scale of its Marcellus position. In connection with the purchase in Pennsylvania, the Company placed $25.0 million in an escrow account, which is reflected as non-current restricted cash on the Consolidated Balance Sheets at December 31, 2009. The Company closed this acquisition on February 22, 2010. At the closing, the Company acquired 78,221 net acres in the deep rights, for a purchase price of $333.0 million, subject to post closing adjustments. The Company may acquire additional interests in these net acres at subsequent closings if the Sellers cure title defects as provided in the purchase agreement.

On January 28, 2010, the Company's subsidiary, Ultra Resources, Inc., agreed to issue an aggregate amount of $500.0 million of Senior Notes (the "2010 Senior Notes") pursuant to a Second Supplement to its Master Note Purchase Agreement dated March 6, 2008. Of the 2010 Senior Notes: $270.0 million of the 2010 Senior Notes were issued January 28, 2010 and $230.0 million of the 2010 Senior Notes were issued February 16, 2010. The 2010 Senior Notes rank pari passu with Ultra Resources' bank revolving credit facility and other outstanding Senior Notes. Payment of the 2010 Senior Notes is guaranteed by the Company and its subsidiary, UP Energy Corporation. Proceeds from the 2010 Senior Notes were used to repay revolving credit facility debt, but did not reduce the borrowings available under the revolving credit facility, and for general corporate purposes, including funding the Pennsylvania Marcellus Shale acquisition that closed on February 22, 2010. Of the 2010 Senior Notes, $116.0 million are 4.98% senior notes due in 2017, $207.0 million are 5.50% senior notes due in 2020, $87.0 million are 5.60% senior notes due in 2022 and $90.0 million are 5.85% senior notes due in 2025.

15. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED):

	2009				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Revenues from continuing operations	$ 167,953	$130,341	$155,164	$213,304	$ 666,762
Gain (loss) on commodity derivatives	206,428	(60,698)	(55,428)	56,215	146,517
Expenses from continuing operations	116,975	98,264	104,131	113,043	432,413
Write-down of oil and gas properties	1,037,000	—	—	—	1,037,000
Interest expense	7,297	9,897	9,744	10,229	37,167
Other (expense) income, net	(2,613)	(505)	193	37	(2,888)
(Loss) income before income tax (benefit) provision	(789,504)	(39,023)	(13,946)	146,284	(696,189)
Income tax (benefit) provision	(276,916)	(13,497)	(5,616)	50,893	(245,136)
(Loss) income from continuing operations	(512,588)	(25,526)	(8,330)	95,391	(451,053)
Net (loss) income	$ (512,588)	$ (25,526)	$ (8,330)	$ 95,391	$ (451,053)
Net (loss) income per common share — basic	$ (3.39)	$ (0.17)	$ (0.06)	$ 0.63	$ (2.98)
Net (loss) income per common share — fully diluted	$ (3.39)	$ (0.17)	$ (0.06)	$ 0.62	$ (2.98)

	2008				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Revenues from continuing operations	$271,137	$308,240	$297,627	$207,396	$1,084,400
(Loss) gain on commodity derivatives	(27,673)	(11,596)	58,117	14,368	33,216
Expenses from continuing operations	107,922	112,346	110,308	111,818	442,394
Interest expense	5,272	4,543	5,183	6,278	21,276
Other income (expense), net	150	127	92	49	418
Income before income tax provision	130,420	179,882	240,345	103,717	654,364
Income tax provision	47,021	63,489	91,370	38,624	240,504
Income from continuing operations	83,399	116,393	148,975	65,093	413,860
Revenues from discontinued operations	(103)	743	—	—	640
Income tax provision — discontinued operations	(36)	261	—	—	225
Net income	$ 83,332	$116,875	$148,975	$ 65,093	$ 414,275

	2008				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Basic Earnings per Share:					
Income per common share from continuing operations	$ 0.55	$ 0.76	$ 0.98	$ 0.43	$ 2.72
Income per common share from discontinued operations	$ —	$ —	$ —	$ —	$ —
Net income per common share — basic	$ 0.55	$ 0.76	$ 0.98	$ 0.43	$ 2.72
Fully Diluted Earnings per Share:					
Income per common share from continuing operations	$ 0.53	$ 0.74	$ 0.95	$ 0.42	$ 2.65
Income per common share from discontinued operations	$ —	$ —	$ —	$ —	$ —
Net income per common share — fully diluted	$ 0.53	$ 0.74	$ 0.95	$ 0.42	$ 2.65

16. 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:

On January 6, 2010, the FASB issued an ASU updating oil and gas reserve estimation and disclosure requirements. The ASU amends FASB ASC 932 to align the reserve calculation and disclosure requirements with the requirements in SEC Release No. 33-8995. The ASU is effective for reporting periods ending on or after December 31, 2009.

On December 31, 2008, the SEC issued SEC Release No. 33-8995, amending oil and gas reporting requirements under Rule 4-10 of Regulation S-X and Industry Guide 2 in Regulation S-K revising oil and gas reserves estimation and disclosure requirements. The new rules include changes to pricing used to estimate reserves, the ability to include non-traditional resources in reserves, the use of new technology for determining reserves and permitting disclosure of probable and possible reserves. The primary objectives of the revisions are to increase the transparency and information value of reserve disclosures and improve comparability among oil and gas companies. The rule is effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. Accordingly, the Company adopted the update to FASB ASC 932 as of December 31, 2009 in order to conform to the requirements in SEC Release No. 33-8995. The implementation of this rule did not result in material additions to the Company's proved reserves included in this report as of December 31, 2009.

In accordance with our three-year planning and budgeting cycle, proved undeveloped reserves included in the current, as well as previous, reserve estimates include only economic well locations that are forecast to be drilled within a three-year period. As a result of our self-imposed three-year limit on proved undeveloped reserves inventory, we have not booked any proved undeveloped reserves beyond five years.

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.

The Director — Reservoir Engineering & Planning is primarily responsible for overseeing the preparation of the Company's reserve estimates by our independent engineers, Netherland, Sewell & Associates, Inc. The Director has a Bachelor of Science degree in Petroleum Engineering and is a licensed Professional Engineer. The Company's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation.

All of the information regarding reserves in this annual report is derived from the report of Netherland, Sewell & Associates, Inc. The report of Netherland, Sewell & Associates, Inc. is included as an Exhibit to this annual report. The principal engineer at Netherland, Sewell & Associates, Inc. responsible for preparing our reserve estimates has a Bachelor of Science degree in Mechanical Engineering and is a licensed Professional Engineer with over 25 years of experience, including significant experience throughout the Rocky Mountain basins.

The following unaudited tables as of December 31, 2009, 2008, 2007 and 2006 are based upon estimates prepared by Netherland, Sewell & Associates, Inc. and estimates prepared by Ryder Scott Company as of December 31, 2006. The estimates for properties in the United States were prepared by Netherland, Sewell & Associates, Inc. in reports dated January 27, 2010, February 6, 2009, and February 4, 2008, respectively. The estimates for properties in China were prepared by Ryder Scott Company in a report dated January, 30, 2007. These are estimated quantities of proved oil and natural gas reserves for the Company and the changes in total proved reserves as of December 31, 2009, 2008 and 2007. All such reserves are located in the Green River Basin in Wyoming and the Appalachian Basin of Pennsylvania.

Since January 1, 2009, no crude oil or natural gas 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.

B. ANALYSES OF CHANGES IN PROVEN RESERVES:

	United States		China		Total	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Reserves, December 31, 2006	17,843	2,258,101	3,987	—	21,829	2,258,101
Extensions, discoveries and additions	6,091	747,914	—	—	6,091	747,914
Sales	—	—	(2,833)	—	(2,833)	—
Production	(870)	(109,178)	(1,153)	—	(2,023)	(109,178)
Revisions	(232)	(54,182)	—	—	(232)	(54,182)
Reserves, December 31, 2007	22,832	2,842,655	—	—	22,832	2,842,655
Extensions, discoveries and additions	6,536	803,200	—	—	6,536	803,200
Production	(1,122)	(138,564)	—	—	(1,122)	(138,564)
Revisions	(1,239)	(151,503)	—	—	(1,239)	(151,503)
Reserves, December 31, 2008	27,007	3,355,788	—	—	27,007	3,355,788
Extensions, discoveries and additions	5,902	758,659	—	—	5,902	758,659
Production	(1,320)	(172,189)	—	—	(1,320)	(172,189)
Revisions	(2,404)	(205,657)	—	—	(2,404)	(205,657)
Reserves, December 31, 2009	29,185	3,736,601	—	—	29,185	3,736,601

	United States		China		Total	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Proved:						
Developed	8,764	1,084,224	—	—	8,764	1,084,224
Undeveloped	14,068	1,758,431	—	—	14,068	1,758,431
Total Proved — 2007	22,832	2,842,655	—	—	22,832	2,842,655
Developed	11,462	1,412,562	—	—	11,462	1,412,562
Undeveloped	15,545	1,943,226	—	—	15,545	1,943,226
Total Proved — 2008	27,007	3,355,788	—	—	27,007	3,355,788
Developed	11,627	1,541,813			11,627	1,541,813
Undeveloped	17,558	2,194,788	—	—	17,558	2,194,788
Total Proved — 2009	29,185	3,736,601	—	—	29,185	3,736,601

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 natural gas 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, 2009 was \$3.04 per Mcf for natural gas and \$52.18 per barrel for condensate, based upon the average of the price in effect on the first day of the month for the preceding twelve month period in accordance with SEC Release No. 33-8995. The calculated weighted average sales prices utilized for the purposes of estimating the Company's proved reserves and future net revenues were $4.71 per Mcf and $6.13 per Mcf of natural gas at December 31, 2008 and 2007, respectively, utilizing prices in effect on the last day of the year. The calculated weighted average oil price at December 31, 2008 and 2007 for Wyoming was $30.10 per barrel and $86.91, respectively, utilizing prices in effect on the last day of the year.

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,		
	2009	2008	2007
Future cash inflows	$12,870,816	$16,608,609	$19,411,520
Future production costs	(3,916,222)	(4,217,034)	(4,233,952)
Future development costs	(2,249,993)	(2,351,312)	(2,100,647)
Future income taxes	(1,998,114)	(3,222,246)	(4,414,331)
Future net cash flows	4,706,487	6,818,017	8,662,590
Discount at 10%	(2,679,787)	(3,800,331)	(4,793,188)
Standardized measure of discounted future net cash flows	$ 2,026,700	$ 3,017,686	$ 3,869,402

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,		
	2009	2008	2007
Standardized measure, beginning	$ 3,017,686	$ 3,869,402	$ 1,871,553
Net revisions of previous quantity estimates	(216,946)	(247,791)	(126,447)
Extensions, discoveries and other changes	782,763	1,313,391	1,784,862
Sales of reserves in place	—	—	(46,451)
Changes in future development costs	(103,056)	(327,325)	(254,538)
Sales of oil and gas, net of production costs	(513,958)	(890,157)	(496,556)
Net change in prices and production costs	(1,772,644)	(1,971,128)	1,607,811
Development costs incurred during the period that reduce future development costs	395,092	503,582	315,523
Accretion of discount	444,387	584,119	269,046
Net changes in production rates and other	(572,380)	(362,018)	11,007
Net change in income taxes	565,756	545,611	(1,066,408)
Aggregate changes	(990,986)	(851,716)	1,997,849
Standardized measure, ending	$ 2,026,700	$ 3,017,686	$ 3,869,402

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,		
	2009	2008	2007
United States			
Acquisition costs — unproved properties	$ 33,176	$ 18,766	$ 7,780
Exploration	102,217	395,970	385,238
Development	605,958	534,914	304,782
Total	$741,351	$949,650	$697,800
China			
Acquisition costs — unproved properties	$ —	$ —	$ 10,356
Development	—	—	4,094
Total	$ —	$ —	$ 14,450
Total			
Acquisition costs — unproved properties	$ 33,176	$ 18,766	$ 18,136
Exploration	102,217	395,970	385,238
Development	605,958	534,914	308,876
Total	$741,351	$949,650	$712,250

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

	Years Ended December 31,		
	2009	2008	2007
United States			
Oil and gas revenue	$ 666,762	$1,084,400	$ 566,638
Production expenses	(152,804)	(194,243)	(115,371)
Depletion and depreciation	(201,826)	(184,795)	(135,470)
Write-down of proved oil and gas properties	(1,037,000)	—	—
Income taxes	254,429	(235,095)	(104,553)
Total	$ (470,439)	$ 470,267	$ 211,244
China			
Oil and gas revenue	$ —	$ —	$ 64,822
Production expenses	—	—	(19,532)
Depletion and depreciation	—	—	(14,981)
Income taxes	—	—	(10,454)
Total	$ —	$ —	$ 19,855
Total			
Oil and gas revenue	$ 666,762	$1,084,400	$ 631,460
Production expenses	(152,804)	(194,243)	(134,903)
Depletion and depreciation	(201,826)	(184,795)	(150,451)
Write-down of proved oil and gas properties	(1,037,000)	—	—
Income taxes	254,429	(235,095)	(115,007)
Total	$ (470,439)	$ 470,267	$ 231,099

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

	December 31,	
	2009	2008
Developed Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	$ 3,544,519	$2,809,082
Less: accumulated depletion, depreciation and amortization	(1,749,916)	(514,100)
	1,794,603	2,294,982
Unproven Properties:		
Acquisition and exploration costs not being amortized	—	55,544
	$ 1,794,603	$2,350,526

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

None.

Item 9A. *Controls and Procedures.*

Management's Report on Assessment of Internal Control Over Financial Reporting

Management's Report on Assessment of Internal Control Over Financial Reporting is included on page 46 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, 2009 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, 2009. The evaluation considered the procedures designed to ensure that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and communicated to our management as appropriate to allow timely decisions regarding required disclosure.

Item 9B. *Other Information.*

None.

Part III

Item 10. *Directors, Executive Officers and Corporate Governance*

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement, which will be filed not later than 120 days after December 31, 2009.

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 363 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, 2009.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*

The information required by Item 403 of Regulation S-K will be included in the Company's definitive proxy statement, which will be filed not later than 120 days after December 31, 2009 and is incorporated herein by reference.

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, 2009.

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, 2009.

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.
10.1	Credit Agreement dated as of April 30, 2007 among Ultra Resources, Inc., JPMorgan Chase Bank, N.A. as Administrative Agent, J.P. Morgan Securities Inc. as Sole Bookrunner and Sole Lead Arranger, and the Lenders party thereto (incorporated by reference to
10.2	Share Purchase Agreement dated September 26, 2007 between UP Energy Corporation and SPC E&P (China) Pte. Ltd. (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed on September 26, 2007).
10.3	Precedent Agreement between Rockies Express Pipeline LLC and Ultra Resources, Inc. dated December 19, 2005 (incorporated by reference to Exhibit 10.1 of the Company's Report of Form 8-K filed on February 9, 2006).
10.4	Precedent Agreement between Rockies Express Pipeline LLC, Entrega Gas Pipeline LLC and Ultra Resources, Inc. dated December 19, 2005 (incorporated by reference to Exhibit 10.2 of the Company's Report on Form 8-K filed on February 9, 2006).
10.5	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).
10.6	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).
10.7	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).

Exhibit Number	Description
10.8	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).
10.9	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).
10.10	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).
10.11	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).
10.12	Sale and Purchase Agreement dated December 18, 2009 between Ultra Resources, Inc. and NCL Appalachian Partners, L.P., Locin Oil Corporation, Lyons Petroleum Reserves, Inc., MC Reserves, Inc., (incorporated by reference to Exhibit 1.1 of the Company's Report on Form 8-K filed on December 23, 2009).
*10.13	Base Contract for Sale and Purchase of Natural Gas dated September 1, 2004 between Ultra Resources, Inc. and Sempra Energy Trading Corp.
*10.14	Base Contract for Sale and Purchase of Natural Gas dated April 17, 2008 between Ultra Resources, Inc. and JP Morgan Chase Bank, National Association.
*10.15	Base Contract for Sale and Purchase of Natural Gas dated June 1, 2004 between Ultra Resources, Inc. and J. Aron & Company.
21.1	Subsidiaries of the Company (incorporated by reference from Exhibit 21.1 of the Company's Annual Report on Form 10-K for the year ended December 31, 2007).
*23.1	Consent of Netherland, Sewell & Associates, Inc.
*23.2	Consent of Ryder Scott Company.
*23.3	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, 2009.
*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

* Filed herewith.

SIGNATURES

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

ULTRA PETROLEUM CORP.

By: /s/ Michael D. Watford
Name: Michael D. Watford
Title: Chairman of the Board,
Chief Executive Officer, and President

Date: February 26, 2010

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 26, 2010
/s/ Marshall D. Smith Marshall D. Smith	Chief Financial Officer (principal financial officer)	February 26, 2010
/s/ Garland R. Shaw Garland R. Shaw	Corporate Controller (principal accounting officer)	February 26, 2010
/s/ W. Charles Helton W. Charles Helton	Director	February 26, 2010
/s/ Stephen J. McDaniel Stephen J. McDaniel	Director	February 26, 2010
/s/ Robert E. Rigney Robert E. Rigney	Director	February 26, 2010
/s/ Roger A. Brown Roger A. Brown	Director	February 26, 2010

CORPORATE INFORMATION

BOARD OF DIRECTORS

Michael D. Watford[1]
Roger A. Brown[2][4]
W. Charles Helton[2][3][4]
Stephen J. McDaniel[2][3][4]
Robert E. Rigney[3]

(1) *Chairman of the Board*
(2) *Member of the Audit Committee*
(3) *Member of the Compensation Committee*
(4) *Member of the Corporate Governance Committee*

CORPORATE OFFICERS

Michael D. Watford
Chairman, President and Chief Executive Officer

Stuart E. Nance
Vice President – Marketing

William R. Picquet
Vice President – Operations

Marshall D. Smith
Chief Financial Officer

Garrett B. Smith
Corporate Secretary

LEGAL COUNSEL

U.S. – Haynes and Boone, L.L.P.
Canada – Bennett Jones LP
Lackowicz, Shier & Hoffman, LP

INDEPENDENT AUDITORS

Ernst & Young LLP
Houston, Texas

INDEPENDENT RESERVE ENGINEERS

Netherland, Sewell & Associates, Inc.
Dallas, Texas

BANK GROUP

JP Morgan Chase Bank, N.A.
BMO Capital Markets Financing, Inc.
BNP Paribas
Bank of America, N.A.
Citibank, N.A.
Deutsche Bank Trust Company Americas
Capital One, N.A.
Comerica Bank
Compass Bank
Frost National Bank
Union Bank of California, N.A.

REGISTRAR AND TRANSFER AGENT

Computershare Investor Services Inc.
Vancouver, British Columbia
Toll Free: 1-800-564-6253
Email: service@computershare.com

CO-TRANSFER AGENT

Computershare Trust Company, N.A.
Denver, Colorado

CERTIFICATIONS

In 2009, Ultra Petroleum's Chief Executive Officer (CEO) provided to the New York Stock Exchange (NYSE) the annual CEO certification regarding Ultra Petroleum's compliance with the NYSE's corporate governance listing standards. In addition, Ultra Petroleum's CEO and Ultra Petroleum's principal financial officer filed with the U.S. Securities and Exchange Commission (SEC) all the required certifications regarding the quality of Ultra Petroleum's public disclosures in its report for the fiscal year 2009.

STOCK EXCHANGE LISTING AND TRADING SYMBOL

New York Stock Exchange: **UPL**
CUSIP: 903914109
Common shares outstanding at December 31, 2009: 151,759,343

ANNUAL MEETING

Ultra Petroleum Corp.'s 2010 Annual Meeting of shareholders will be held at the Crowne Plaza Hotel, 425 N. Sam Houston Parkway E., Houston, Texas, on June 14, 2010 at 10:00 a.m. (Central Daylight Savings Time). All shareholders are invited to attend the meeting. Shareholders are asked to sign and return the proxy form mailed with this report to ensure representation. The annual report is not intended to be considered a part of the proxy soliciting material.

HEAD OFFICE

363 N. Sam Houston Parkway E.
Suite 1200
Houston, Texas 77060

Tel: 281-876-0120
Fax: 281-876-2831
email: info@ultrapetroleum.com

www.ultrapetroleum.com

ABOUT THE COVER

Ultra's success is built on the foundation of our outstanding employees who execute tirelessly day in and day out.

NAS • BILL PICQUET • BOB VIRGIN • BRAD JOHNSON • BRANT WITZEL • BRUCE OSTENDORF • CALLY MCKEE •
MAJEWSKI • DAVE SMITH • DEBBIE GHANI • DOUG SELVIUS • DWAYNE JOHNSTON • ERIC POBUDA • ERIK WIL-
LLIAMS • HENRY LAW • JAMES LAIN • JANA DITTON • JASON GAINES • JEANETTE BOWEN • JIM PORTER • JIM
ER • JOSH REIN • JULIE DANVERS • JUSTIN SANDIFER • KELLY PREUIT • KELLY WHITLEY • KENT ROGERS • KENT
KELMAN • MAREE DELGADO • MARK POTTER • MARK SMITH • MARY POBUDA • MATTHEW HEDTKE • MICHAEL
ANDERSON • PRESTON VENABLE • RALPH TROTTER • REBECCA TOWNSEND • REYNE JOHN • RHONDA
HEHN • RYAN LEWIS • SALLY ZINKE • SAM MCCLURE • SARAH GACH • SARAH SANCHEZ • SCOTT ROGERS •
DON • TERRY ALLEN • TIM WAITE • TOM WILSON • TROY GRAHAM • TYLER BELL • WENDY BOMAN

Ultra Petroleum Corp. • 363 N. Sam Houston Parkway E. Suite 1200 • Houston, Texas 77060 • 281-876-0120 • www.ultrapetroleum.com

AARON STERCK • ADRIANN PALUMBO • ALAN BOYER • ANDREA PAULSEN • ANNETTE VOSKIAN • BELINDA SA
CARL BRACKLEIN • CARLOS MARTINEZ • CHUCK SNYDER • CODY HILL • DAN BULFER • DAVE HODGES • DAV
LIAMS • ERIKA TOKARZ • FRED ARCHAMBAULT • GARLAND SHAW • GARRETT SMITH • GREG SHORT • GREG W
PREVOST • JOE GARCIA • JOE MURDOCK • JOHN LUSTER • JOHN WALTER • JOSEPH COMMODORE • JOSEPH LUS
WILKINSON • KEVIN WRIGHT • LARRY BRYAN • LARRY TAVEGIA • LINDA MEYER • LOREN KJORSTAD • MARC B
BLACKSTONE • MICHAEL WATFORD • MIKE HELWIG • NICKI SMALDONE • NORMA MENDEZ • PRESTON
SNYDER • RICHARD SEIFERT • RICKY LITZEL • ROBIN FOUNTAIN • RON AUFLICK • RON SHERBROOK • RYAN
SHANE DEAL • SHANE REES • STACI GORDON • STUART NANCE • TAMMY WIDHALM • TERESA BRA