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, 2011

☐ **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)*
400 North Sam Houston Parkway East, Suite 1200, Houston, Texas	**77060**
(Address of principal executive offices)	*(Zip code)*

(281) 876-0120

(Registrant's telephone number, including area code)

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

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

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

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

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

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

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

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

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

Large accelerated filer ☑	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was $7,003,851,599 as of June 30, 2011 (based on the last reported sales price of $45.80 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 10, 2012 was 152,502,577.

Documents incorporated by reference: The definitive Proxy Statement for the 2012 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2011, 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 hydrocarbon which is produced in association with natural gas production that condenses from natural gas as it is produced and delivered into a separator or similar equipment prior to the delivery of such natural gas to the natural gas gathering pipeline system.
- ***MBbl*** — One thousand barrels of crude oil or other liquid hydrocarbons.
- ***Mcf*** — One thousand cubic feet of natural gas.
- ***Mcfe*** — One thousand cubic feet of natural gas equivalent, converting oil or condensate to natural gas at the ratio of 1 Bbl of oil or condensate to 6 Mcf of natural gas. This conversion ratio, which is typically used in the oil and gas industry, represents the approximate energy equivalent of a barrel of oil or condensate to an Mcf of natural gas. The sales price of one barrel of oil or condensate has been much higher than the sales price of six Mcf of natural gas over the last several years, so a six to one conversion ratio does not represent the economic equivalency of six Mcf of natural gas to one barrel of oil or condensate.
- ***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 available geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward from known reservoirs and under existing economic conditions, operating methods, and government regulation — before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

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

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

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

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

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

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

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

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

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price is the average price during the 12-month period before the ending date of the period covered by the report, determined as an 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.

Other Terms

- ***All-in costs*** — The sum of costs per Mcfe relating to lease operating expenses, severance taxes, gathering costs, transportation charges, depletion, depreciation and amortization, interest expense and general and administrative expenses.
- ***Reserve replacement ratio*** — The sum of the estimated net proved reserves added through discoveries, extensions, infill drilling and acquisitions (which may include or exclude reserve revisions of previous estimates) for a specified period of time divided by production for that same period of time.
- ***Finding and development costs*** — Finding and development costs, including revisions, are calculated by dividing the sum of property acquisition costs, exploration costs and development costs for the year, by the total of reserve extensions, discoveries, purchases and all revisions for the year.

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 the north-central Pennsylvania area of the Appalachian Basin. In addition, the Company has recently acquired acreage in eastern Colorado's Denver Julesburg Basin.

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

Oil and Gas Properties Overview

Ultra's current operations in southwest Wyoming are focused on developing its long-life natural gas reserves 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, 2011, Ultra owned interests in approximately 93,000 gross (53,000 net) acres in Wyoming covering approximately 190 square miles.

Ultra's current operations in north-central Pennsylvania are focused on assessing, exploring and developing its position in the Marcellus Shale and other horizons. At December 31, 2011, the Company owned interests in approximately 499,000 gross (258,000 net) acres in Pennsylvania.

In eastern Colorado, the Company acquired 149,000 gross (130,000 net) acres during the year ended December 31, 2011. Ultra's operations in this area will be focused on assessing, exploring and developing its position targeting the Niobrara formation in the Denver Julesburg Basin.

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 seeks to maintain a portfolio of properties that provide long-term, profitable 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 twelve years, Ultra has consistently delivered meaningful reserve and production growth. In 2011, oil and natural gas production increased 15% over 2010 levels and estimated proved reserves increased 13% to 5.0 Tcfe from 4.4 Tcfe with return on capital employed of 13% and return on equity of 31%.

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. For the year ended 2011, the Company's all-in costs were $2.88 per Mcfe with finding and development costs of $1.60 per Mcfe.

Financial Flexibility. Preserving financial flexibility and a strong balance sheet are also strategic to Ultra's business philosophy. At December 31, 2011, the Company had cash on hand of $11.3 million and outstanding debt was $1.9 billion. Consistent with this strategy and in anticipation of the upcoming maturity of the Company's (through its subsidiary, Ultra Resources) senior, unsecured revolving 2007 Credit Agreement ("2007 Credit Agreement"), the Company replaced the 2007 Credit Agreement in its entirety with a new senior, unsecured revolving credit facility and repaid all amounts under the 2007 Credit Agreement with proceeds of loans drawn under the new facility during the fourth quarter of 2011. The Company's average debt maturity profile is approximately eight years while the Company's weighted average cost of debt is approximately 4.9%.

Exploration and Production

Green River Basin, Wyoming

During 2011, the Company participated in the drilling of 235 wells in Wyoming and continued to improve its drilling and completion efficiency on its operated wells as measured by spud to total depth. During 2011, the Company averaged 12 days to drill a well, as measured by spud to total depth. This compares to an average of 14 days to drill during 2010, a 14% reduction. Similarly, Ultra reached total depth in 15 days or less on 95% of all operated wells during 2011 as compared to 76% of all operated wells during the prior year. Total days per well, measured by rig-release to rig-release, decreased 12% to 15 days in 2011 compared to 17 days during 2010.

During 2012, 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 2012 in the Pinedale or Jonah fields will target the sands of the upper Cretaceous Lance Pool.

Additionally, the Company plans to continue its assessment of increased density drilling to more efficiently recover the oil and gas resources present in the area. During 2011, based on results of its 5-acre wells drilled in 2010, Ultra sought and obtained approval from the WOGCC to file for development of its acreage in Pinedale at a well density of 32 wells per 160-acre government quarter section (5-acre equivalent). 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 refine areas of drilling focus, to identify areas for future extension of the Lance fairway and to identify deeper objectives which may warrant drilling.

Pennsylvania

Ultra continued the assessment of its acreage in Pennsylvania during 2011. During the year, the Company participated in the drilling of 161 horizontal wells and continued to evaluate the 3D seismic data on its properties.

The Company is actively leveraging its Pinedale experience by translating its Wyoming directional drilling, completion and production knowledge to the Marcellus. During 2012, the Company plans to continue executing 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, Clinton, Centre and Lycoming counties. Activities include lease acquisition, 3-D seismic, drilling, completion, infrastructure construction and production operations.

Colorado

During 2011, the Company acquired an acreage position in eastern Colorado's Denver Julesburg Basin with plans to explore and develop the Niobrara formation. During 2012, the Company plans to acquire additional acreage and drill and complete several exploration wells to evaluate the potential for oil production from its acreage.

Marketing and Pricing

Overview

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. An increasing portion of the Company's revenues is associated with gas sales from wells operated by the Company and others 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 ("REX") in 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 natural gas prices in particular, have been highly volatile, and such volatility is expected to continue in the future.

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 now 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.

Midstream services. For its natural gas production in Wyoming, the Company has entered into various gathering and processing agreements with several midstream service providers that gather, compress and process natural gas owned or controlled by the Company from its producing wells in the Pinedale Anticline and Jonah fields. Under these agreements, the midstream service providers have routinely expanded their facilities' capacities in southwest Wyoming to accommodate growing volumes from wells in which the Company owns an interest. Such expansions are continuing and 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.

During December 2011, a fire occurred at the Jonah Gas Gathering system's Falcon Compressor station in Sublette County, Wyoming, which caused damage to the compression and disrupted production from the

Pinedale field from December 6, 2011 until December 31, 2011. The owner and operator of the Jonah Gas Gathering system was able to re-provision some of its existing and surplus pipeline and compression facilities to replace the capacity at the Falcon station that was lost to the fire and was able to restore its capacity to receive and compress the Company's gas to "pre-fire" levels by the end of December 2011. Plans are currently being developed for specific actions to permanently replace the compression capacity lost during the fire.

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 is expected to continue throughout 2012, so the Company can continue to manage its midstream capacity to coincide with increased capacity requirements from its drilling activities. These facilities are gathering systems and related infrastructure, and their construction is expected to continue, to some extent, until the Company's properties in Pennsylvania are fully developed. To date, none of the Company's natural gas production in Pennsylvania has required processing, treating or blending in order to remove natural gas liquids or other impurities and it is anticipated that treating facilities of this type will not be required in the future to accommodate the Company's production.

Pipeline infrastructure. The Company has taken actions to facilitate expansion of the pipeline infrastructure available to move its natural gas supplies across the country, to provide sufficient capacity to transport its natural gas production and to provide for reasonable prices for its natural gas in the future. Such actions include becoming an anchor shipper on REX, which begins at the Opal Processing Plant in southwest Wyoming and traverses Wyoming and several other states to an ultimate terminus in eastern Ohio. In addition, during 2011, two new pipeline projects, plus expansion of an existing pipeline, all originating in Wyoming and designed to transport natural gas to markets not previously accessible to Wyoming producers, were placed into service, further increasing pipeline takeaway capacity from Wyoming. The Ruby Pipeline began deliveries of gas to Northern California markets in July 2011. The Bison Pipeline commenced delivery service in January 2011. The Kern River Pipeline APEX expansion, serving markets in and near Las Vegas, Nevada, was placed into service in October 2011. These three pipeline projects have added aggregate export pipeline capacity for Rockies/Wyoming gas of approximately 2.1 Bcf per day, a more than 20% increase over previous levels. The Company evaluated and declined the opportunity to commit to hold firm transportation rights on these three new pipeline projects. The new pipeline projects have afforded the Company the benefit of improved market access as well as tightening of the Rockies basis differential, as described below.

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 somewhat unpredictable and are beyond the Company's ability to control. These factors include, among others, weather, natural gas supplies, natural gas demand, inventory levels in natural gas storage fields, and natural gas pipeline capacity to export gas from the Rockies.

The Rocky Mountain region is a net exporter of natural gas because local natural gas production exceeds local demand, especially during non-winter months. As a result, natural gas production in southwest Wyoming has 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. These differentials are also reflective of the general relative abundance of, or lack of, export pipeline capacity to move gas out of the Rockies. The Inside FERC First of Month Index for Northwest Pipeline — Rocky Mountains basis was generally wide since 2006 but narrowed during the latter portion of 2009 and has continued to narrow during 2011, primarily as a result of the completion of the REX pipeline into Ohio, as well as additional export capacity out of the Rocky Mountain region in general. (See *Pipeline Infrastructure* above).

The table below provides a historical and future perspective on average annual basis differentials for Wyoming natural gas (NW Rockies) and historically premium markets in the Northeast (Dominion South). The basis differential is expressed as a percentage of the Henry Hub price as reported by Platt's M2M (Mark to Market) Report on December 31, 2011.

	2008	2009	2010	2011	2012	2013	2014
NW Rockies	69%	77%	90%	94%	96%	96%	98%
Dominion South	105%	107%	104%	104%	101%	99%	99%

Derivatives

The Company, from time to time and 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 (See Note 13), 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.

In response to the lower price environment resulting from the supply/demand imbalance during 2011, the Company continued to hedge a portion of its exposure to volatile natural gas prices by entering into forward swaps for 2011 through 2012. This strategy of hedging will result in greater price certainty for the Company's production and helps protect the Company's capital investment program for those years. For a more detailed description of the Company's hedging activities, see Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

The Company's hedging policy limits the amounts of resources hedged to not more than 50% of its forecast production without Board approval. As of January 1, 2009, 2010 and 2011, the quantities that the Company hedged for the succeeding twelve month periods represented 53%, 46% and 67%, respectively, of the Company's forecasted production for such periods. During 2009 and 2011, Ultra's board approved hedges of greater than 50% of the Company's forecast production for each respective period.

Oil Marketing

The Company markets its Wyoming condensate to various purchasers, which are primarily refiners in the Salt Lake City, Utah area. The pricing realized from the sale of the Company's condensate production was more volatile during 2011 than in 2010, as a result of convergence of geopolitical factors, burgeoning domestic oil production growth and resulting, historically wide differential (discount) between European and U.S. oil futures prices. The Company's condensate realized pricing is typically based on New York Mercantile Exchange crude futures daily settlement prices, less a negotiated location/transportation discount or differential. All of the Company's condensate sales are denominated in U.S. dollars per barrel and are paid for on a monthly basis. The Company routinely maintains only operating inventories of condensate production and sells its product on an "as produced" basis. A portion of the Company's condensate sales are done by its operating partners in the Pinedale field.

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. Commencing in 2010, the Company began gathering its operated condensate production in its liquids gathering system, which is designed to gather condensate from various leases and wells operated by the Company as contemplated under the Supplemental Environment Impact Statement ("SEIS") and Record of Decision ("ROD") as discussed below in Environmental Matters. The condensate is transported through the liquids gathering system to four central gathering facilities in the Pinedale field where it can be loaded into trucks or delivered into pipelines for delivery to the Company's customers. At the end of 2011, more than 80% of the Company's operated condensate production in Wyoming was delivered from the Company's liquids gathering system directly into a pipeline, further reducing truck traffic and improving flow assurance as well as realized pricing.

Significant Counterparties

A significant counterparty is defined as one that individually accounts for 10% or more of the Company's total revenues during the year. In 2011, the Company had no single counterparty that represented 10% or more of the Company's total revenues.

The Company maintains credit policies intended to mitigate the risk of uncollectible accounts receivable related to the sale of natural gas and condensate as well as commodity derivatives. A more complete description of the Company's credit policies are described in Note 13. The Company did not have any outstanding, uncollectible accounts for its natural gas and oil sales at December 31, 2011.

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 Jonah field on a well density of two wells per 80-acre drilling and spacing unit as opposed to the one well per 80-acre drilling and spacing unit as was approved in the initial Jonah field EIS approved in 1998. The new EA was completed in June 2000. With the approval of this EA and the earlier approval by the WOGCC for drilling of two wells per 80-acre drilling and spacing unit, the Company was permitted to drill infill wells at this well density on the 2,160 gross (1,322 net) acres then owned by the Company in the Jonah field. Subsequently, various other operators have received approval for the drilling of increased density wells in pilot areas at well densities ranging from four wells per 80-acre drilling and spacing unit to sixteen wells per 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 2011, Ultra and other operators in the Pinedale field received approval from the WOGCC to drill increased density and pilot project wells in several areas in the Lance Pool across the Pinedale field. During 2011, based on results of its 5-acre wells drilled in 2010, Ultra sought and obtained approval from the WOGCC to file for development of its acreage in Pinedale at a well density of 32 wells per 160-acre government quarter section (5-acre equivalent). 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).

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

The final ROD 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 “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 low levels of contaminants 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, federal, state and local regulation of oil and natural gas production and transportation, including regulations governing environmental quality, pollution control and limits on allowable rates of production by a well or proration unit; the amount of oil and natural gas available for sale; the availability of adequate pipeline and other transportation and processing facilities; and the marketing of competitive fuels.

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

- The location of wells;
- The method of drilling, completing and operating wells;
- The surface use and restoration of properties upon which wells are drilled;
- The plugging and abandoning of wells; and
- Notice to surface owners and other third parties.

State and federal regulations are generally intended to prevent waste of oil and natural gas, protect rights to produce oil and natural gas between owners in a common reservoir, control the amount of oil and natural gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines and natural gas plants operated by other companies that provide midstream services to the Company are also subject to the jurisdiction of various federal, state and local authorities, which can affect our operations. State laws also regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and gas properties.

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

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

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

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

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

Surface Damage Acts

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

Environmental Regulations

General. The Company's exploration, drilling and production activities from wells and 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, 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.

Safe Drinking Water Act. Many of the Company's exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. Congress has periodically considered legislation to amend the federal Safe Drinking Water Act to remove the exemption from permitting and regulation provided to injection for hydraulic fracturing and to require the disclosure and reporting of the chemicals used in hydraulic fracturing. This type of federal legislation, if adopted, could lead to additional regulation and permitting requirements that could result in operational delays making it more difficult to perform hydraulic fracturing and increasing our costs of compliance and operating costs.

In addition, EPA has recently been taking activity to assert federal regulatory authority over hydraulic fracturing using diesel under the Safe Drinking Water Act's Underground Injection Control Program. Further, in March 2010, the EPA announced that it would conduct a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. Interim results of the study are expected in 2012, with final results expected in 2014. In addition, in December 2011, the EPA published a draft report in which it asserts that hydraulic fracturing caused groundwater pollution in a natural gas field in Wyoming (not a field in which the Company owns any interest); this report has been publicly criticized by industry and government officials, including the Governor of Wyoming; it remains subject to review and public comment. The agency also announced that one of its enforcement initiatives for 2011 to 2013 would be to focus on environmental compliance by the energy extraction sector. This study and enforcement initiative could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

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

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

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

Air Emissions. The Company's operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. Federal and state laws generally require new and modified sources of air pollutants to obtain permits prior to commencing construction, which may require, among other things, stringent, technical controls. Other federal and state laws designed to control hazardous (toxic) air pollutants might require installation of additional controls. Administrative agencies can bring actions for failure to comply with air pollution regulations or permits and generally enforce compliance through administrative, civil or criminal enforcement actions, which may result in fines, injunctive relief and imprisonment.

On July 28, 2011, EPA proposed a rule to subject oil and gas operations to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) programs under the Clean Air Act, and to impose new and amended requirements under both programs. Under the proposal, EPA would, among other things, amend standards applicable to natural gas processing plants and would expand the NSPS to include all oil and gas operations, imposing requirements on those operations. EPA is also proposing NSPS standards for completions of hydraulically fractured gas wells. The proposed standards include the reduced emission completion techniques. The NESHAPS proposal includes maximum achievable control technology (MACT) standards for certain glycol dehydrators and storage vessels, and revises applicability provisions, alternative test protocols and the availability of the startup, shutdown and maintenance exemption. EPA is under a court order to finalize the rules, with the current deadline of April 3, 2012. Should these rules become final and applicable to our operations, they could result in increased operating and compliance costs, increased regulatory burdens and delays in our operations.

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 to include, among other things, certain wetlands. Under the Clean Water Act, permits must be obtained for the routine discharge of pollutants into waters of the United States. The CWA provides for administrative, civil and criminal penalties for unauthorized discharges, both routine and accidental, of pollutants and of oil and hazardous substances. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or hazardous substances. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters. In addition, the EPA has promulgated regulations that may require permits to discharge storm water runoff, including discharges associated with construction activities.

RCRA and comparable state and local programs impose requirements on the management, treatment, storage and disposal of both hazardous and nonhazardous solid wastes. Many of the wastes that we generate are currently exempt from hazardous waste regulation under RCRA, but may be subject to state and local regulation or could in the future lose their RCRA exemption, which would result in more rigorous and costly management and disposal requirements.

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. In June 2010, EPA published its GHG tailoring rule phasing in federal prevention of significant deterioration (PDS) permit requirements for new sources and modifications, and Title V operating permits for all sources, that have the potential to emit specific quantities of GHGs. These permitting provisions, when they become applicable to our operations, could require controls or other measures to reduce GHG emissions from new or modified sources, and the Company could incur additional costs to satisfy those requirements. In November 2010, EPA published a rule establishing GHG reporting requirements for sources in the petroleum and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions, with the first annual report, for 2011, being due in September 2012. Although the rule does not limit the amount of GHGs that can be emitted, it could require us to incur significant costs to monitor, keep records of, and report GHG emissions associated with our operations.

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

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

Employees

As of December 31, 2011, the Company had 116 full-time employees, including officers.

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

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

There are numerous uncertainties inherent in estimating quantities of proved reserves and projected future rates of production and timing of development expenditures, including many factors beyond our control. The reserve data and standardized measures set forth herein represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers often vary. In addition, drilling, testing and production data acquired subsequent to the date of an estimate may justify revising such estimates. Accordingly, reserve estimates are often different from the quantities of oil 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, prices and future operating costs are subject to great uncertainty, and the meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based.

The present value, 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 and complete wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;
- our ability to retain the personnel necessary to properly evaluate seismic and other information relating to a property;
- our ability to procure materials, equipment and services required to explore, develop and operate our properties; 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 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 the 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 instruments fails to perform the contracts.

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

During 2010, the President signed into law the Dodd–Frank Wall Street Reform and Consumer Protection Act (the "Act"). Among other things, the Act requires the Commodity Futures Trading Commission and the SEC to enact regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the over-the-counter market. We cannot predict the content of these regulations or the effect that these regulations will have on our hedging activities. Of particular concern, the Act does not explicitly exempt end users (such as us) from the requirement to use cleared exchanges, rather than hedging over-the-counter, and the requirements to post margin in connection with hedging activities. If the regulations ultimately adopted require that we post margin for our hedging activities or require our counterparties to hold margin or maintain capital levels, the cost of which could be passed through to us, or impose other requirements that are more burdensome than current regulations, our hedging would become more expensive and we may decide to alter our hedging strategy.

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, which include, but are not limited to: changes in the supply of and demand for oil and natural gas; market uncertainty; 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; 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.

A substantial portion of our reserves and production is natural gas. Prices for natural gas have been lower in recent years than at various times in the past and may remain lower in the future. Sustained low prices for natural gas may adversely effect our operational and financial condition.

Natural gas prices have been lower in recent years than at various times in the past. These lower prices may be the result of increased supply resulting from among other things, increased drilling in unconventional reservoirs and/or lower demand resulting from reduced economic activity associated with the recent recession. Natural gas prices may remain at current levels, or fall to lower levels, in the future. Approximately 96% of our estimated net proved reserves is natural gas, and 97% of our production in 2011 was natural gas. Although we expect operations on properties we currently own to be profitable at natural gas prices in effect during the past year, a period of sustained low natural gas prices could have an adverse effect on our results of operation and financial condition.

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

Our operations are subject to numerous laws and regulations relating to environmental protection. These laws and regulations may:

- require that we acquire permits before developing 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, greenhouse gases and hydraulic fracturing. We maintain limited insurance coverage for sudden and accidental environmental damages, but do not maintain insurance coverage for the full potential liability that could be caused by accidental environmental damages. Accordingly, we may be subject to liability in excess of our insurance coverage or may be required to cease production from properties in the event of environmental damages.

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

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

On December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other gases which the EPA refers to as "greenhouse gases" ("GHGs") create risks 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 GHGs 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 GHGs from motor vehicles and could trigger permit review for GHG emissions from certain stationary sources.

In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA published its amendments to the GHG reporting rule to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities, which may include facilities we operate. Reporting of GHG emissions from such facilities will be required on an annual basis beginning in 2012 for emissions occurring in 2011. We will have to incur costs associated with this reporting obligation.

In addition, the United States Congress has considered legislation to reduce emissions of GHGs and many states have already taken legal measures to reduce or measure GHG emission levels, often involving the planned development of GHG emission inventories and/or regional cap and trade programs. Most of these cap and trade programs require major sources of emissions or major producers of fuels to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to reduce overall GHG emissions. The cost of these allowances could escalate significantly over time. The adoption and implementation of any legislation or regulatory programs imposing GHG reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce.

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

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

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

Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions but is not subject to regulation at the federal level (except for fracturing activity involving the use of diesel). The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with interim results of the study anticipated to be available by late 2012, and final results anticipated in 2014. In addition, in December 2011, the EPA published a draft report in which it asserts that hydraulic fracturing caused groundwater pollution in a natural gas field in Wyoming (not a field in which the Company owns an interest); this report has been publicly criticized by industry and by government officials, including the Governor of Wyoming; it remains subject to review and public comment. A committee of the U.S. House of

Representatives is also conducting an investigation of hydraulic fracturing practices. Legislation was introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed. Wyoming has adopted regulations requiring us to provide detailed information about wells we hydraulically fracture in that state. Any other new laws or regulations that significantly restrict hydraulic fracturing could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby affect our determination of whether a well is commercially viable. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. We have conducted hydraulic fracturing operations on most of our existing wells, and we anticipate conducting hydraulic fracturing operations on substantially all of our future wells. As a result, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities.

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 successfully raised capital during 2011, 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 and 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.

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

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, discharges of toxic gases, underground migration and surface spills or mishandling of fracture fluids, including chemical additives. The occurrence of any of these events with respect to any property we own or operate (in whole or in part) could have a material adverse impact on us. We and the operators of our properties maintain insurance in accordance with customary industry practices and in amounts that management believes to be reasonable. However, insurance coverage is not always economically feasible and is not obtained to cover all types of operational risks. The occurrence of a significant event that is not fully insured could have a material adverse effect on our financial condition.

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

Our oil and natural gas operations are subject to all of the risks and hazards typically associated with drilling 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 and completing 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.

A prospect is an area in which our geoscientists have identified what they believe, based on available seismic and geological information, to be indications of hydrocarbons. Our prospects are in various stages of review. Whether or not we ultimately drill our prospects depends on many factors, including but not limited to: 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; the availability and cost of capital; changes in the estimates of costs to drill or complete wells; decisions of our joint working interest owners; and regulatory and permitting requirements. It is possible that these factors and others 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 write down 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, timing and costs of drilling, completion, and other development activities on our non-operated properties depend on a number of factors that are beyond our control. Because we have only a limited ability to influence and control the operations of our non-operated properties, we can give no assurances that we will realize our targeted returns with respect to those properties.

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

We acquired a portion of our acreage position in Pennsylvania and Colorado through property acquisitions and acreage trades, and we may acquire additional acreage in Colorado, 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;
- our ability to respond to low natural gas prices;
- business strategies and plans of management; and

- prospect development and property acquisitions.

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

- 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 and oil and gas leases and fee minerals in Colorado. The leases in Wyoming are primarily federal leases with 10-year lease terms until establishment of production. Production extends the lease terms until cessation of that production. In Pennsylvania, the leases are from private individuals and companies, as well as from the Commonwealth of Pennsylvania. The leases in Pennsylvania are mostly undeveloped at this time and typically have primary lease terms of five years until establishment of production. In Colorado, our oil and gas leases are from private individuals and companies, as well as from the State of Colorado, and typically have primary lease terms of five years. All of our acreage in Colorado is undeveloped at this time.

Green River Basin, Wyoming

As of December 31, 2011, the Company owned developed oil and natural gas leases totaling approximately 93,000 gross (53,000 net) acres in the southwest Wyoming's Green River Basin. Most of this acreage covers Pinedale and Jonah fields in Sublette County, Wyoming, with some smaller undeveloped acreage blocks located north and west of Pinedale. Of the total acreage position in Wyoming, approximately 22,000 gross (10,000 net) acres were developed, and 71,000 gross (43,000 net) acres were undeveloped. The developed portion represents 31% of the Company's total developed net acreage while the undeveloped portion represents approximately 11% of the Company's total undeveloped net acreage.

Lease maintenance costs in Wyoming were approximately $0.2 million for the year ended December 31, 2011. The Company currently owns 39 leases totaling 74,000 gross (37,000 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.

Development Wells. During 2011, the Company participated in the drilling of 198 gross (112.88 net) productive development wells on the Green River Basin properties. At year end 2011, there were 35 gross (17.79 net) additional development wells that commenced during the year and were either still drilling or had operations suspended at a depth short of total depth.

Exploratory Wells. During 2011, the Company participated in the drilling of a total of 2 gross (0.61 net) productive exploratory wells on the Green River Basin properties. At December 31, 2011, there were no 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.

Pennsylvania

As of December 31, 2011, the Company owned oil and gas leases covering 499,000 gross (258,000 net) acres in the Pennsylvania portion of the Appalachian Basin. This acreage is located in the heart of northeast Pennsylvania's Marcellus Shale Gas Trend, principally in Potter, Tioga, Lycoming, Centre and Clinton counties. Of the total acreage position as of December 31, 2011, approximately 38,000 gross (22,000 net) acres were developed, and 461,000 gross (236,000 net) acres were undeveloped. The developed portion represents 69% of the Company's total developed net acreage position while the undeveloped portion represents 58% of the Company's total undeveloped net acreage position. The Company operates approximately 84,000 gross (58,000 net) acres of the total position.

Lease maintenance costs in Pennsylvania were approximately $3.3 million for the year ended December 31, 2011. The Company owns approximately 362,000 gross (185,000 net) acres currently held by production or activities in Pennsylvania.

Development Wells. During 2011, the Company participated in the drilling of 136 gross (61.67 net) productive development wells in Pennsylvania, all of which were horizontal wells. At year end 2011, there were 6 gross (2.10 net) additional development wells that commenced during the year and were either still drilling or had operations suspended at a depth short of total depth.

Exploratory Wells. During the year ended December 31, 2011, the Company participated in the drilling of a total of 49 gross (25.47 net) productive exploratory wells on the Pennsylvania properties. Of that total, 18 gross (9.47 net) were horizontal wells and 31 gross (16.00 net) were vertical wells. At December 31, 2011, there was 1 gross (0.50 net) additional exploratory well that commenced during the year that was either still drilling or had operations suspended at a depth short of total depth and thus a determination of productive capability could not be made at year end.

Seismic Activity. The Company did not acquire any 3D seismic data on its properties during 2011. The Company's total 3D seismic coverage in Pennsylvania is 315 square miles. Of this, 285 square miles of data is owned with other parties, and 30 square miles is owned solely by the Company.

Denver Julesburg Basin, Colorado

As of December 31, 2011, the Company owned fee minerals and oil and gas leases covering 149,000 gross (130,000 net) acres in eastern Colorado's Denver Julesburg Basin. The total acreage in Colorado represents approximately 32% of the Company's undeveloped net acreage position.

Lease maintenance costs in Colorado were immaterial for the year ended December 31, 2011. All of the Colorado acreage is undeveloped at this time; none of it is held by production.

Exploratory Wells. The Company did not participate in drilling any exploratory wells in Colorado during 2011.

Development Wells. The Company did not participate in drilling any development wells in Colorado during 2011.

Seismic Activity. The Company acquired ownership rights to 22 square miles of 3D seismic data in El Paso County, Colorado and licensed an additional 126 miles of 2D data in the same county. This represents the Company's total seismic position in the area.

Oil and Gas Reserves

The following table sets forth the Company's quantities of proved reserves for the years ended December 31, 2011, 2010, and 2009 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, 2011, 2010 and 2009. As of December 31, 2011, proved undeveloped reserves represent 58.9% of the Company's total proved reserves. The Company's proved undeveloped reserves are limited to economic locations that are scheduled in accordance with the Company's current planning and budgeting process. The inventory of bookable locations available to the Company is substantially larger than the amount ultimately included in the Company's year-end reserves. From time to time, the Company may adjust the inventory and schedule of its proved undeveloped locations in response to changes in capital budget, economics, new opportunities in the portfolio or resource availability. The Company has not scheduled any proved undeveloped reserves beyond five years nor does it have any proved undeveloped locations that have been part of its inventory of proved undeveloped locations for over five years.

Our policies and practices regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and gas reserves quantities and present values in compliance with the SEC's regulations and GAAP. The Vice President — Reservoir Engineering & Development is primarily responsible for overseeing the preparation of the Company's reserve estimates by our independent engineers, Netherland, Sewell & Associates, Inc. The Vice President — Reservoir Engineering and Development has a Bachelor and Master of Science degree in Petroleum Engineering and is a licensed Professional Engineer with over 17 years of experience. The Company's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation. Our internal professional staff works closely with our independent engineers to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their evaluation of our reserves.

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.

In estimating proved reserves and future net revenue as of December 31, 2011, the Company's independent reserve engineer, Netherland, Sewell & Associates, Inc., used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The reserves were estimated using deterministic methods; these estimates were prepared in accordance with generally accepted petroleum engineering and evaluation principles. Standard engineering and geoscience methods, such as performance analysis, volumetric analysis and analogy, that were considered to be appropriate and necessary to establish reserve quantities and reserve categorization that conform to SEC definitions and rules and regulations, were also used. In evaluating the information at their disposal, Netherland, Sewell & Associates, Inc. excluded from their consideration all matters as to which the controlling interpretation may be legal or accounting, rather than engineering and geoscience. As in all aspects of oil and natural gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, Netherland, Sewell & Associates, Inc.'s conclusions necessarily represent only informed professional judgment.

As a result of Ultra's drilling activities in 2011, 330.3 Bcfe (13%) of reserves classified as proved undeveloped at January 1, 2011 were converted into proved developed reserves. Proved undeveloped reserves increased as a result of ongoing drilling and development activities. The Company did not have any material changes to proved undeveloped volumes due to revisions during the year ended December 31, 2011.

	December 31,		
	2011	2010	2009
Proved Developed Reserves			
Natural gas (MMcf)	1,973,391	1,678,697	1,541,813
Oil (MBbl)	11,794	11,013	11,627
Proved Undeveloped Reserves			
Natural gas (MMcf)	2,805,163	2,521,458	2,194,788
Oil (MBbl)	21,287	20,671	17,558
Total Proved Reserves (MMcfe)(1)	4,977,040	4,390,259	3,911,711
Estimated future net cash flows, before income tax	$ 11,789,256	$ 10,879,719	$ 6,704,601
Standardized measure of discounted future net cash flows, before income taxes(2)	$ 5,296,964	$ 4,993,576	$ 2,887,125
Future income tax	$ 1,500,908	$ 1,468,008	$ 860,425
Standardized measure of discounted future net cash flows, after income tax	$ 3,796,056	$ 3,525,568	$ 2,026,700
Calculated average price(3)			
Gas ($/Mcf)	$ 4.035	$ 4.05	$ 3.04
Oil ($/Bbl)	$ 88.19	$ 68.93	$ 52.18

(1) Oil and condensate are converted to natural gas at the ratio of one barrel of oil or condensate to six Mcf of natural gas. This conversion ratio, which is typically used in the oil and gas industry, represents the approximate energy equivalent of a barrel of oil or condensate to an Mcf of natural gas. The sales price of one barrel of oil or condensate has been much higher than the sales price of six Mcf of natural gas over the last several years, so a six to one conversion ratio does not represent the economic equivalency of six Mcf of natural gas to one barrel of oil or condensate.

(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, 2011, 2010 and 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.

Since January 1, 2011, 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, 2011	2010	2009
	(In thousands, except per unit data)		
Production			
Natural gas (Mcf)	236,832	205,613	172,189
Oil (Bbl)	1,408	1,334	1,320
Total (Mcfe)	245,280	213,619	180,110
Revenues			
Natural gas sales	$ 982,413	$886,396	$601,023
Oil sales	119,383	92,990	65,739
Total revenues	$1,101,796	$979,386	$666,762
Lease Operating Expenses			
Production costs(a)	$ 51,758	$ 45,938	$ 40,679
Severance/production taxes	97,094	95,914	66,970
Gathering	56,511	50,126	45,155
Total lease operating expenses	$ 205,363	$191,978	$152,804
Realized prices			
Natural gas ($/Mcf, including realized gains (losses) on commodity derivatives)	$ 5.05	$ 4.88	$ 4.88
Natural gas ($/Mcf, excluding realized gains (losses) on commodity derivatives)	$ 4.15	$ 4.31	$ 3.49
Oil ($/Bbl)	$ 84.79	$ 69.69	$ 49.80
Costs per Mcfe			
Production costs	$ 0.21	$ 0.22	$ 0.23
Severance/production taxes	$ 0.40	$ 0.45	$ 0.37
Gathering	$ 0.23	$ 0.23	$ 0.25
Transportation charges	$ 0.26	$ 0.30	$ 0.32
DD&A	$ 1.41	$ 1.13	$ 1.12
General & administrative	$ 0.11	$ 0.11	$ 0.11
Interest	$ 0.26	$ 0.23	$ 0.21
Total costs per Mcfe	$ 2.88	$ 2.68	$ 2.61

The following table sets forth the net sales volumes attributable to field(s) that contain 15% or more of our total estimated proved reserves as of December 31, 2011:

	Year ended December 31, 2011	2010	2009
	(In thousands)		
Pinedale Field (Mcfe)	196,236	190,849	170,148

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

Delivery Commitments

With respect to the Company's natural gas production, from time to time the Company enters into transactions to deliver specified quantities of gas to its customers. As of February 16, 2012, the Company had long-term natural gas delivery commitments of 2.6 MMMBtu in 2012, 9.9 MMMBtu in 2013 and 1.8 MMMBtu in 2014 under existing agreements. None of these commitments require the Company to deliver gas produced specifically from any of the Company's properties, and all of these commitments are priced on a floating basis with reference to an index price. These amounts are well below the Company's forecasted 2012 and anticipated 2013 and 2014 production from its available reserves. In addition, none of the Company's reserves are subject to any priorities or curtailments that may affect quantities delivered to its customers, any priority allocations or price limitations imposed by federal or state regulatory agencies or any other factors beyond the Company's control that may affect its ability to meet its contractual obligations other than those discussed in Item 1A. "Risk Factors". The Company believes that its production and reserves are adequate to meet its delivery commitments. If for some reason the Company's production is not sufficient to satisfy its delivery commitments, the Company expects to be able to purchase natural gas production in the market to satisfy its commitments.

With respect to the Company's oil production, the Company does not have any long-term arrangements that commit the Company to deliver a fixed or determinable quantity of oil in the near future.

Productive Wells

As of December 31, 2011 the Company's total gross and net wells were as follows:

Productive Wells*	Gross Wells	Net Wells
Natural Gas and Condensate	2,137.0	1,063.5

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

Oil and Gas Acreage

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

The Company does not believe the remaining terms of its leases is material. At December 31, 2011, the Company had 5,300 net acres of leases in Pennsylvania, 700 net acres of leases in Wyoming and no leases in Colorado that expire in 2012 and it expects to maintain over 90% of those leases by production, operations, extensions or renewals. The Company does not expect to lose material lease acreage because of failure to drill due to inadequate capital, equipment or personnel. The Company has, based on its evaluation of prospective economics, allowed acreage to expire and it may allow additional acreage to expire in the future.

As of December 31, 2011 the Company had total gross and net developed and undeveloped oil and natural gas leasehold acres in the United States as set forth below.

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Wyoming	22,000	10,000	71,000	43,000
Pennsylvania	38,000	22,000	461,000	236,000
Colorado	—	—	149,000	130,000
All States	60,000	32,000	681,000	409,000

Drilling Activities

For each of the three fiscal years ended December 31, 2011, 2010 and 2009 the number of gross and net wells drilled by the Company was as follows:

Wyoming — Green River Basin

	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	198.00	112.88	168.00	90.62	155.00	76.09
Dry	—	—	—	—	—	—
Total	198.00	112.88	168.00	90.62	155.00	76.09

At year end, there were 35 gross (17.79 net) additional development wells that were either drilling or had operations suspended. This includes wells in both the Pinedale and Jonah fields.

	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	2.00	0.61	13.00	3.91	8.00	2.80
Dry	—	—	—	—	—	—
Total	2.00	0.61	13.00	3.91	8.00	2.80

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

Pennsylvania

	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	136.00	61.67	30.00	19.00	—	—
Dry	—	—	—	—	—	—
Total	136.00	61.67	30.00	19.00	—	—

At year end, there were 6 gross (2.1 net) additional development wells that were either drilling or had operations suspended.

	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	49.00	25.47	141.00	80.00	35.00	21.00
Dry	—	—	—	—	—	—
Total	49.00	25.47	141.00	80.00	35.00	21.00

At year end, there was 1 gross (0.5 net) additional exploratory well that was either drilling or had operations suspended.

Colorado

	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total	—	—	—	—	—	—

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

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. ***[Removed and Reserved].***

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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.

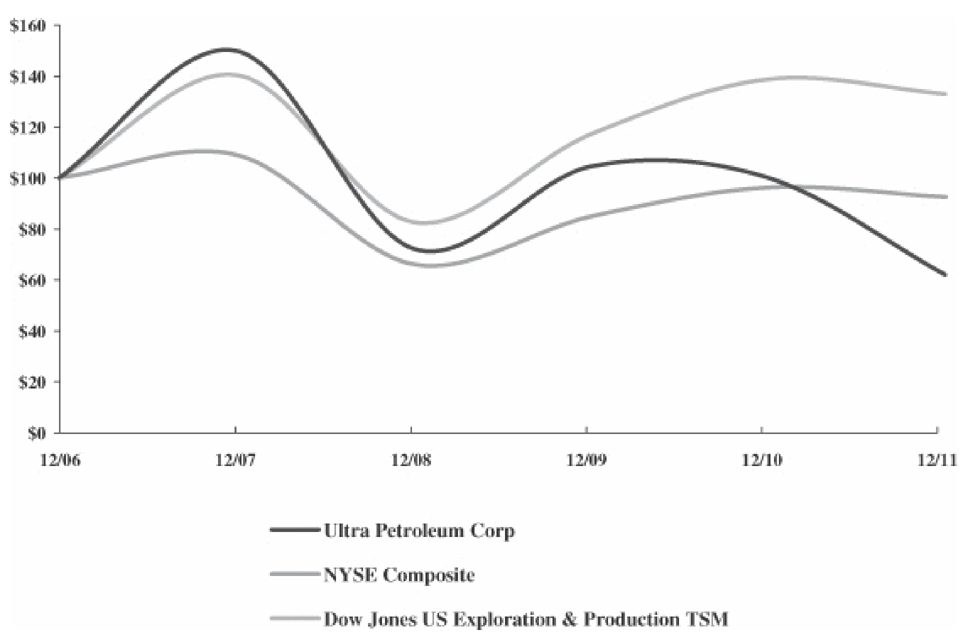
The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the appreciation of the Company's common stock relative to two broad-based stock performance indices. The information is included for historical comparative purposes only and should not 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 TSM Index from December 31, 2006 through December 31, 2011.

2011	High	Low
1st quarter	$50.97	$41.83
2nd quarter	$51.20	$42.90
3rd quarter	$47.89	$27.56
4th quarter	$36.72	$24.39

2010	High	Low
1st quarter	$53.90	$42.67
2nd quarter	$53.85	$40.40
3rd quarter	$47.70	$37.10
4th quarter	$50.22	$39.14

As of February 10, 2012, the last reported sales price of the common stock on the NYSE was $23.59 per share and there were approximately 373 holders of record of the common stock.

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 12/31/06 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

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	12/06	12/07	12/08	12/09	12/10	12/11
Ultra Petroleum Corp	**100.00**	**149.77**	**72.29**	**104.44**	**100.06**	**62.07**
NYSE Composite	**100.00**	**108.87**	**66.13**	**84.83**	**96.19**	**92.50**
Dow Jones US Exploration & Production TSM	**100.00**	**140.30**	**82.74**	**117.09**	**138.63**	**132.95**

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

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.

On May 17, 2006, the Company announced that its Board of Directors authorized a share repurchase program for up to an aggregate $1 billion of the Company's outstanding common stock which has been and will be funded by cash on hand and the Company's senior credit facility.

Period	Total Number of Shares Repurchased (000's)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (000's)	Maximum Number (or Approximate Dollar Value) of Shares That May Yet be Purchased Under the Plans or Programs
December 2011	252	$ 30.44	252	$386 million

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

The selected consolidated financial information presented below for the years ended December 31, 2011, 2010, 2009, 2008 and 2007 is derived from the Consolidated Financial Statements of the Company.

	Year Ended December 31,				
	2011	2010	2009	2008	2007
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Natural gas sales	$ 982,413	$ 886,396	$ 601,023	$ 986,374	$ 509,140
Oil sales	119,383	92,990	65,739	98,026	57,498
Total operating revenues	1,101,796	979,386	666,762	1,084,400	566,638
Expenses:					
Production expenses and taxes	205,363	191,978	152,804	194,243	115,371
Transportation charges	64,243	64,965	58,011	46,310	—
Depletion, depreciation and amortization	346,394	241,796	201,826	184,795	135,470
Write-down of proved oil and gas properties	—	—	1,037,000	—	—
General and administrative	12,113	11,407	8,871	11,230	7,543
Stock compensation	13,919	12,944	10,901	5,816	5,718
Interest expense	63,156	49,032	37,167	21,276	17,760
Total operating expenses	705,188	572,122	1,506,580	463,670	281,862
Other:					
Gain on commodity derivatives	313,732	325,452	146,517	33,216	—
Litigation expense	—	(9,902)	—	—	—
Other income (expense) , net	532	260	(2,888)	833	1,087
Total other income (expense), net	314,264	315,810	143,629	34,049	1,087
Income (loss) before income taxes	710,872	723,074	(696,189)	654,779	285,863
Income tax provision (benefit)	257,670	258,615	(245,136)	240,504	105,621
Net income (loss) from continuing operations	$ 453,202	$ 464,459	$ (451,053)	$ 414,275	$ 180,242
Income from discontinued operations (includes pre-tax gain on sale of $98,066)	—	—	—	—	82,794
Net income (loss)	$ 453,202	$ 464,459	$ (451,053)	$ 414,275	$ 263,036
Basic Earnings per Share:					
Income (loss) per common share from continuing operations	$ 2.97	$ 3.05	$ (2.98)	$ 2.72	$ 1.19
Income per common share from discontinued operations	$ —	$ —	$ —	$ —	$ 0.54
Net income (loss) per common share — basic	$ 2.97	$ 3.05	$ (2.98)	$ 2.72	$ 1.73
Fully Diluted Earnings per Share:					
Income (loss) per common share from continuing operations	$ 2.94	$ 3.01	$ (2.98)	$ 2.65	$ 1.14
Income per common share from discontinued operations	$ —	$ —	$ —	$ —	$ 0.52
Net income (loss) per common share — fully diluted	$ 2.94	$ 3.01	$ (2.98)	$ 2.65	$ 1.66
Statement of Cash Flows Data:					
Net cash provided by (used in):					
Operating activities	$ 1,033,292	$ 824,728	$ 592,641	$ 840,803	$ 427,949
Investing activities	$ (1,408,795)	$ (1,529,099)	$ (820,611)	$ (915,319)	$ (507,070)
Financing activities	$ 315,976	$ 760,951	$ 228,067	$ 78,041	$ 75,179
Balance Sheet Data:					
Cash and cash equivalents	$ 11,307	$ 70,834	$ 14,254	$ 14,157	$ 10,632
Working capital (deficit)	$ (251,059)	$ (56,967)	$ (137,450)	$ (149,355)	$ (67,505)
Oil and gas properties	$ 4,189,148	$ 3,075,670	$ 1,794,603	$ 2,350,526	$ 1,574,529
Total assets	$ 4,869,705	$ 3,595,615	$ 2,060,005	$ 2,558,162	$ 1,751,582
Total long-term debt	$ 1,903,000	$ 1,560,000	$ 795,000	$ 570,000	$ 290,000
Other long-term obligations	$ 67,008	$ 52,575	$ 35,858	$ 46,206	$ 26,672
Deferred income taxes, net	$ 635,009	$ 420,711	$ 239,217	$ 503,597	$ 341,406
Total shareholders' equity	$ 1,593,709	$ 1,138,976	$ 648,197	$ 1,090,786	$ 857,546

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

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

Overview

Ultra Petroleum Corp. is an independent exploration and production company focused on developing its long-life natural gas reserves in the Green River Basin of Wyoming — the Pinedale and Jonah fields — and is in the early exploration and development stages in the Appalachian Basin of Pennsylvania. In addition, the Company has recently acquired acreage in eastern Colorado's Denver Julesburg Basin. The Company operates in one industry segment, natural gas and oil exploration and development, with one geographical segment, the United States.

The Company currently conducts operations exclusively in the United States. Substantially all of its oil and natural gas activities are conducted jointly with others and, accordingly, amounts presented reflect only the Company's proportionate interest in such activities. Inflation has not had a material impact on the Company's results of operations. The Company continues to focus on improving its drilling and production results through gaining efficiencies with the use of advanced technologies, detailed technical analysis of its properties and leveraging its experience into improved operational efficiencies. Inflation is not expected to have a material impact on the Company's results of operations in the future.

The Company currently generates its revenue, earnings and cash flow primarily from the production and sales of natural gas and condensate from its property in southwest Wyoming with an increasing portion of the Company's revenues coming from gas sales from wells located in the Appalachian Basin in Pennsylvania.

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 swap agreements and/or fixed price forward physical delivery contracts for natural gas. The average price realization for the Company's natural gas during 2011 was $5.05 per Mcf, including realized gains and losses on commodity derivatives. During the quarter ended December 31, 2011, the average price realization for the Company's natural gas was $4.77 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 $4.15 per Mcf and $3.69 per Mcf for the year and quarter ended December 31, 2011, respectively. (See Note 8).

Mission and 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 seeks to maintain a portfolio of properties that provide long-term, profitable 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 twelve years, Ultra has consistently delivered meaningful reserve and production growth.

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. Maintaining financial discipline enables the Company to capitalize on the flexibility of its portfolio.

2011 Operating Highlights

The Company has consistently delivered meaningful reserve and production growth over the past ten years and management believes it has the ability to continue growing production by drilling already identified locations on its core properties. Highlights for 2011 include:

- Achieved production of 245.3 Bcfe, a 15% increase as compared to 2010;
- Proved reserves increased 13% to 5.0 Tcfe from 4.4 Tcfe in 2010;
- Finding and development costs of $1.60 per Mcfe as compared to $1.48 per Mcfe in 2010;
- Reserve replacement ratio of 339% as compared to 324% in 2010;
- Reduced average drilling time to 12 days per well in Wyoming, spud to total depth, a 14% reduction from 2010;
- 95% of wells drilled in Wyoming in less than 15 days as compared to 76% in 2010;
- Initiated production from 112 gross (59 net) horizontal wells in Pennsylvania;
- All-in costs of $2.88 per Mcfe;
- Acquired 149,000 gross (130,000 net) acres targeting the Niobrara formation in the Denver Julesburg Basin in eastern Colorado, and
- Return on capital employed of 13% and return on equity of 31%.

The following table illustrates the Company's production growth over the past ten years:

	2011	2010	2009	2008	2007	2006	2005	2004	2003	2002
Production — (Bcfe)	245.3	213.6	180.1	145.3	121.3	91.6	73.8	49.5	28.9	17.4

2011 Financial Highlights

Significant 2011 financial highlights include:

- Generated $1.033 billion of cash flow from operating activities compared with $824.7 million in 2010 due primarily to increased production volumes during 2011;
- Replaced the 2007 Credit Agreement with the 2011 Credit Agreement with an initial loan commitment of $1.0 billion (which may be increased up to $1.25 billion at the borrower's request and with the consent of the lenders);
- As of December 31, 2011, the Company had entered into commodity derivative contracts for 2012 representing 129.1 MMMBtu at a weighted average price of $ 5.02 per MMBtu in order to manage price risk on a portion of its natural gas production.
- Subsequent to December 31, 2011, the Company entered into additional commodity derivative contracts for 2012 representing 55.0 MMMBtu at a weighted average price of $3.02 per MMBtu.

Critical Accounting Policies

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

Oil and Gas Reserves. The reserve estimates presented herein were made in accordance with oil and gas reserve estimation and disclosure authoritative accounting guidance according to FASB ASC 932 as updated in order to align the reserve calculation and disclosure requirements with those in SEC Release No. 33-8995.

The Company's proved undeveloped reserves are limited to economic locations that are scheduled in accordance with the Company's current planning and budgeting process. The inventory of bookable locations available to the Company is substantially larger than the amount ultimately included in the Company's year-end reserves. From time to time, the Company may adjust the inventory and schedule of its proved undeveloped locations in response to changes in capital budget, economics, new opportunities in the portfolio or resource availability. The Company has not scheduled any proved undeveloped reserves beyond five years nor does it have any proved undeveloped locations that have been part of its inventory of proved undeveloped locations for over five years.

The Company 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 & Associates, Inc., 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.

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

Full Cost Method of Accounting. The 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.

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. 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 Company did not have any write-downs related to the full cost ceiling limitation in 2011 or 2010.

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.

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 was no resulting effect on overall cash flow, total assets, total liabilities or total stockholders' equity.

Fair Value Measurements. The Company follows FASB ASC Topic 820, Fair Value Measurements and Disclosures ("FASB ASC 820. Under FASB ASC 820, fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at measurement date and establishes a three level hierarchy for measuring fair value. The valuation assumptions 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). See Note 9 for additional information.

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, 2011 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	$ —	$230,385	$ —	$230,385

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

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(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, 2011, 2010 and 2009 was $13.9 million, $12.9 million and $10.9 million, respectively. See Note 7 for additional information.

Recent accounting pronouncements. In May 2011, the FASB issued ASU No. 2011-04, which amends FASB ASC 820. The amended guidance clarifies many requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements. Additionally, the amendments clarify the FASB's intent about the application of existing fair value measurement requirements. The guidance provided in ASU No. 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The Company does not expect the adoption of this amendment to have a material impact on its consolidated financial statements.

Results of Operations — Year Ended December 31, 2011 vs. Year Ended December 31, 2010

During the year ended December 31, 2011, production increased on a gas equivalent basis to 245.3 Bcfe from 213.6 Bcfe for the same period in 2010 attributable to the Company's successful drilling activities during 2011. Realized natural gas prices, including realized gain and loss on commodity derivatives, increased to $5.05 per Mcf during the year ended December 31, 2011 as compared to $4.88 per Mcf during 2010. During the year ended December 31, 2011, the Company's average price for natural gas was $4.15 per Mcf, excluding realized gains and losses on commodity derivatives as compared to $4.31 per Mcf for the same period in 2010. The increase in production largely contributed to a 12% increase in revenues for the year ended December 31, 2011 to $1.1 billion as compared to $979.4 million in 2010.

Lease operating expenses ("LOE") increased to $51.8 million for the year ended December 31, 2011 compared to $45.9 million during the same period in 2010 due primarily to increased well counts resulting from the Company's drilling program. On a unit of production basis, LOE costs decreased to $0.21 per Mcfe at December 31, 2011 compared to $0.22 per Mcfe at December 31, 2010 as a result of increased production volumes.

During the year ended December 31, 2011, production taxes were $97.1 million compared to $95.9 million during the same period in 2010, or $0.40 per Mcfe, compared to $0.45 per Mcfe. Production taxes are calculated based on a percentage of revenue from production in Wyoming after certain deductions and were 8.8% of revenues for the year ended 2011 and 9.8% for the same period in 2010. The decrease in per unit taxes is primarily attributable to increased production in Pennsylvania, which is not subject to production taxes, as well as the decrease in average natural gas prices, excluding the effects of commodity derivatives, during the year ended December 31, 2011 as compared to the same period in 2010.

Gathering fees increased to $56.5 million for the year ended December 31, 2011 compared to $50.1 million during the same period in 2010 largely due to increased production volumes. On a per unit basis, gathering fees remained flat at $0.23 per Mcfe for the years ended December 31, 2011 and 2010.

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 $64.2 million for the period ended December 31, 2011 as compared to $65.0 million for the same period in 2010 in association with REX Pipeline transportation charges. On a per unit basis, transportation charges decreased to $0.26 per Mcfe (on total company volumes) for the period ended December 31, 2011 as compared to $0.30 for the same period in 2010 due to the increase in total company production volumes during the period ended December 31, 2011.

DD&A increased to $346.4 million during the period ended December 31, 2011 from $241.8 million for the same period in 2010, attributable to increased production volumes and a higher depletion rate. On a unit of production basis, DD&A increased to $1.41 per Mcfe at December 31, 2011 from $1.13 at December 31, 2010 largely as a result of increased well costs in Pennsylvania.

General and administrative expenses increased to $26.0 million for the period ended December 31, 2011 compared to $24.4 million for the same period in 2010. 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 remained flat at $0.11 per Mcfe for the years ended December 31, 2011 and 2010.

Interest expense increased to $63.2 million during the period ended December 31, 2011 compared to $49.0 million during the same period in 2010 as a result of increased borrowings outstanding during the period ended December 31, 2011. For the years ended December 31, 2011 and 2010, the Company capitalized $30.7 million and $21.2 million, respectively, in interest associated with unevaluated oil and gas properties that are excluded from amortization and actively being evaluated as well as work in process relating to gathering systems that are not currently in service. At December 31, 2011, the Company had $1.9 billion in borrowings outstanding.

During the year ended December 31, 2010, the Company recognized litigation expenses of $9.9 million related to the resolution of litigation matters.

During the year ended December 31, 2011, the Company recognized $213.3 million related to realized gain on commodity derivatives as compared to $116.8 million during the year ended December 31, 2010. The realized gain or loss on commodity derivatives relates to actual amounts received or paid under the Company's derivative contracts.

At December 31, 2011, the Company recognized $100.4 million related to unrealized gain on commodity derivatives as compared to $208.6 million related to unrealized gain on commodity derivatives at December 31, 2010. The unrealized gain or loss on commodity derivatives represents the non-cash change in the fair value of these derivative instruments.

The Company recognized income before income taxes of $710.9 million for the year ended December 31, 2011 compared with $723.1 million for the same period in 2010. The decrease in earnings is primarily a result of increased DD&A expense during 2011 and partially offset by increased revenues during 2011.

The income tax provision recognized for the year ended December 31, 2011 was $257.7 million compared with an income tax provision of $258.6 million for the year ended December 31, 2010.

For the year ended December 31, 2011, the Company recognized net income of $453.2 million or $2.94 per diluted share as compared with net income of $464.5 million or $3.01 per diluted share for the same period in 2010. The decrease is primarily attributable to increased DD&A expense during 2011 and partially offset by increased revenues during 2011.

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Results of Operations — Year Ended December 31, 2010 vs. Year Ended December 31, 2009

During the year ended December 31, 2010, production increased on a gas equivalent basis to 213.6 Bcfe from 180.1 Bcfe for the same period in 2009 attributable to the Company's successful drilling activities during 2010. Realized natural gas prices, including realized gain and loss on commodity derivatives, remained flat at $4.88 per Mcf during the years ended December 31, 2010 and 2009. During the year ended December 31, 2010, the Company's average price for natural gas was $4.31 per Mcf, excluding realized gains and losses on commodity derivatives as compared to $3.49 per Mcf for the same period in 2009. The increase in production contributed to a 47% increase in revenues for the year ended December 31, 2010 to $979.4 million as compared to $666.8 million in 2009.

LOE increased to $45.9 million for the year ended December 31, 2010 compared to $40.7 million during the same period in 2009 due primarily to increased well counts resulting from the Company's drilling program. On a unit of production basis, LOE costs decreased to $0.22 per Mcfe at December 31, 2010 compared to $0.23 per Mcfe at December 31, 2009 as a result of increased production volumes.

During the year ended December 31, 2010, production taxes were $95.9 million compared to $67.0 million during the same period in 2009, or $0.45 per Mcfe, compared to $0.37 per Mcfe. The increase in per unit taxes is attributable to increased sales revenues as a result of higher realized gas prices (excluding realized gain on commodity derivatives) during the year ended December 31, 2010 as compared to the same period in 2009. Production taxes are calculated based on a percentage of revenue from production and were 9.8% of revenues for the year ended 2010 and 10.0% for the same period in 2009.

Gathering fees increased to $50.1 million for the year ended December 31, 2010 compared to $45.2 million during the same period in 2009 largely due to increased production volumes. On a per unit basis, gathering fees decreased to $0.23 per Mcfe for the year ended December 31, 2010 as compared to $0.25 per Mcfe for the same period in 2009.

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 $65.0 million for the period ended December 31, 2010 as compared to $58.0 million for the same period in 2009 in association with REX Pipeline transportation charges. On a per unit basis, transportation charges decreased to $0.30 per Mcfe (on total company volumes) for the period ended December 31, 2010 as compared to $0.32 for the same period in 2009 due to the increase in total company production volumes during the period ended December 31, 2010 and partially offset by increased transportation rates as a result of further eastern expansion of REX.

DD&A increased to $241.8 million during the period ended December 31, 2010 from $201.8 million for the same period in 2009, attributable to increased production volumes. On a unit of production basis, DD&A increased to $1.13 per Mcfe at December 31, 2010 from $1.12 at December 31, 2009.

General and administrative expenses increased to $24.4 million for the period ended December 31, 2010 compared to $19.8 million for the same period in 2009. 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 remained flat at $0.11 per Mcfe for the years ended December 31, 2010 and 2009.

Interest expense increased to $49.0 million during the period ended December 31, 2010 compared to $37.2 million during the same period in 2009 as a result of increased borrowings during the period ended December 31, 2010. For the year ended December 31, 2010, the Company capitalized $21.2 million in interest associated with unevaluated oil and gas properties that are excluded from amortization and actively being evaluated as well as work in process relating to gathering systems that are not currently in service. There was no interest capitalized during the year ended December 31, 2009. At December 31, 2010, the Company had $1.6 billion in borrowings outstanding.

Other expense for the year ended December 31, 2009 includes rig termination payments of $2.9 million that were not incurred during 2010.

During the year ended December 31, 2010, the Company recognized litigation expenses of $9.9 million related to the resolution of litigation matters.

During the year ended December 31, 2010, the Company recognized $116.8 million related to realized gain on commodity derivatives as compared to $239.4 million during the year ended December 31, 2009. The realized gain or loss on commodity derivatives relates to actual amounts received or paid under the Company's derivative contracts.

At December 31, 2010, the Company recognized $208.6 million related to unrealized gain on commodity derivatives as compared to $92.8 million related to unrealized loss on commodity derivatives at December 31, 2009. The unrealized gain or loss on commodity derivatives represents the change in the fair value of these derivative instruments.

The Company recognized income before income taxes of $723.1 million for the year ended December 31, 2010 compared with a loss of $696.2 million for the same period in 2009. The increase in earnings is primarily a result of the non-cash write-down of oil and gas properties associated with the ceiling test limitation during the first quarter of 2009, increased production during 2010 and unrealized gains on commodity derivatives during the period ended December 31, 2010 as compared to the same period in 2009.

The income tax provision recognized for the year ended December 31, 2010 was $258.6 million compared with an income tax benefit of $245.1 million for the year ended December 31, 2009 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, 2010, the Company recognized net income of $464.5 million or $3.01 per diluted share as compared with a net loss of $451.1 million or ($2.98) per diluted share for the same period in 2009. The increase is primarily attributable to the non-cash write-down of oil and gas properties associated with the ceiling test limitation during the first quarter of 2009, increased production during 2010 and unrealized gains on commodity derivatives during the year ended December 31, 2010 as compared to the same period in 2009.

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, 2011, the Company relied on cash provided by operations along with borrowings under its senior credit facility to finance its capital expenditures. The Company participated in 385 wells that were drilled to total depth in Wyoming and Pennsylvania during 2011. For the year ended December 31, 2011, total capital expenditures were $1.54 billion ($1.43 billion related to oil and gas exploration and development expenditures, $84.0 million related to gathering system expenditures and $21.9 million related to land and other property costs).

At December 31, 2011, the Company reported a cash position of $11.3 million compared to $70.8 million at December 31, 2010. Working capital deficit at December 31, 2011 was $251.1 million compared to a deficit of $57.0 million at December 31, 2010. At December 31, 2011, the Company had $343.0 million in outstanding borrowings under the bank credit facility and $657.0 million of available borrowing capacity under the credit facility. In addition, the Company had $1.6 billion outstanding in senior notes (See Note 6). Other long-term obligations of $67.0 million at December 31, 2011 is comprised of items payable in more than one year, primarily related to production taxes and asset retirement obligations.

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 2012, which is currently projected to be approximately $925.0 million. Of the $925.0 million budget, the Company plans to allocate approximately 75% to exploration and development related expenditures and the remainder to gathering and infrastructure and other.

Bank indebtedness. The Company (through its subsidiary, Ultra Resources) was a party to a revolving credit facility with a syndicate of banks led by JP Morgan Chase Bank, N.A. which was to mature in April 2012 (the "2007 Credit Agreement"). On October 6, 2011, in anticipation of the upcoming maturity of the 2007 Credit Agreement, the Company, through Ultra Resources (the "Borrower"), replaced the 2007 Credit Agreement in its entirety with a senior unsecured revolving credit facility with JP Morgan Chase Bank, N.A. as administrative agent, and the lenders party thereto (the "2011 Credit Agreement") and repaid all amounts outstanding under the 2007 Credit Agreement with proceeds of loans drawn under the 2011 Credit Agreement.

The 2011 Credit Agreement reflects an increased borrowing capacity as compared to the 2007 Credit Agreement with an initial loan commitment of $1.0 billion (which may be increased up to $1.25 billion at the request of the Borrower and with the lenders' consent), provides for the issuance of letters of credit of up to $250.0 million in aggregate, and matures in five years (which term may be extended for up to two successive one-year periods at the Borrower's request and with the lenders' consent).

Loans under the 2011 Credit Agreement are unsecured and bear interest, at the Borrower's option, based on (A) a rate per annum equal to the prime rate or the weighted average fed funds rate on overnight transactions during the preceding business day plus 50 basis points, or (B) a base Eurodollar rate, substantially equal to the LIBOR rate, in either case plus a margin based on a grid of the Borrower's consolidated leverage ratio (for Eurodollar borrowings, 175 basis points per annum as of December 31, 2011). Payment of loans under the 2011 Credit Agreement are guaranteed by Ultra Petroleum Corp. and UP Energy Corporation.

The 2011 Credit Agreement contains typical and customary representations, warranties, covenants and events of default. The 2011 Credit Agreement includes restrictive covenants requiring the Borrower to maintain a consolidated leverage ratio of no greater than three and one half times to one and, as long as 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 no less than one and one half times to one. At December 31, 2011, the Company was in compliance with all of its debt covenants under the 2011 Credit Agreement. (See Note 6).

Senior Notes: The Company's Senior Notes rank pari passu with the Company's 2011 Credit Agreement. Payment of the Senior Notes is guaranteed by Ultra Petroleum Corp. and UP Energy Corporation.

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, 2011, the Company was in compliance with all of its debt covenants under the Senior Notes. (See Note 6).

Operating Activities. During the year ended December 31, 2011, net cash provided by operating activities was $1.033 billion, a 25% increase from $824.7 million for the same period in 2010. The increase in net cash provided by operating activities was largely attributable to increased production during the year ended December 31, 2011 as compared to the same period in 2010.

Investing Activities. During the year ended December 31, 2011, net cash used in investing activities was $1.4 billion as compared to $1.5 billion for the same period in 2010. The decrease in net cash used in investing activities is largely due to the investments associated with the Pennsylvania Marcellus Shale acquisition in 2010, partially offset by increased capital investments associated with the Company's drilling activities in 2011 as compared to 2010.

Financing Activities. During the year ended December 31, 2011, net cash provided by financing activities was $316.0 million as compared to $761.0 million for the same period in 2010. The decrease in cash provided by net financing activities is largely due to increased borrowings during 2010, primarily attributable to the 2010 Senior Notes offerings totaling approximately $1.025 billion.

Outlook

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 2011, the Company established new production records while maintaining a low cost structure. The Company's low cost structure contributes to the Company's favorable returns and growth profile.

Although our net cash provided by operating activities was negatively affected by continued low natural gas prices, we believe that we will continue to generate positive cash flow from operations, which, along with our available cash, will provide sufficient liquidity to fund our capital investments and operations over the next twelve months. We continue to monitor and evaluate the impact of reduced commodity prices in order to determine the appropriate size and nature of our capital investment program.

We expect to rely on our available cash, our existing credit facility and the cash generated from operations to meet our obligations. While we continue to monitor the overall health of the credit markets, 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.

OFF BALANCE SHEET ARRANGEMENTS

The Company did not have any off-balance sheet arrangements as of December 31, 2011.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2011:

	Payments Due by period:				
	Total	Less than 1 year	1 to 3 years	3 to 5 years	More than 5 years
	(Amounts in thousands of U.S. dollars)				
Long-term debt (See Note 6)	$1,903,000	$ —	—	$505,000	$1,398,000
Transportation contract (REX)(1)	776,328	103,578	204,218	201,845	266,687
Drilling contracts	60,463	45,478	14,985	—	—
Office space lease	2,514	973	1,541	—	—
Total contractual obligations	$2,742,305	$150,029	$220,744	$706,845	$1,664,687

(1) The Company's average net interest in payments related to REX transportation charges is approximately 80%.

Transportation contract. The Company is an anchor shipper on REX securing pipeline infrastructure providing sufficient capacity to transport a portion of its natural gas production away from its properties and to provide for reasonable basis differentials for its natural gas in the future. REX begins at the Opal Processing Plant in southwest Wyoming and traverses Wyoming and several other states to an ultimate terminus in eastern

Ohio. The Company's commitment involves a capacity of 200 MMMBtu per day of natural gas for a term of 10 years commencing in November 2009. During the first quarter of 2009, the Company entered into agreements to secure an additional capacity of 50 MMMBtu per day on the REX pipeline system, beginning in January 2012 through December 2018. The Company is obligated to pay REX certain demand charges related to its rights to hold this firm transportation capacity as an anchor shipper. The Company has the right, but not the obligation, to deliver its natural gas production into the REX pipeline, but must pay its reservation charges in either event. The Company continuously assesses its best available market options when determining the appropriate level of utilization of its REX capacity.

Drilling contracts. As of December 31, 2011, the Company had committed to drilling obligations with certain rig contractors that will continue into 2013. The drilling rigs were contracted to fulfill the 2012-2013 drilling program initiatives in Wyoming.

Office space lease. The Company maintains office space in Colorado, Texas, Wyoming and Pennsylvania with total remaining commitments for office leases of $2.5 million at December 31, 2011 ($1.0 million in 2012 and $1.5 million in 2013 to 2015).

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

Objectives and Strategy: The Company's major market risk exposure is in the pricing applicable to its natural gas and oil production. Realized pricing is currently driven primarily by the prevailing price for the Company's Wyoming natural gas production. Historically, prices received for natural gas production have been volatile and unpredictable. Pricing volatility is expected to continue.

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 provided operational flexibility to curtail gas production in the event of 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 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 or natural gas futures settlement prices as traded on the NYMEX.

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

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At December 31, 2011, 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 9 for the detail of the asset and liability values of the following derivatives. The Board has approved our hedging greater than 50% of our forecast 2012 production.

Type	Commodity Reference Price	Remaining Contract Period	Volume - MMBTU/Day	Average Price/MMBTU	Fair Value - December 31, 2011 Asset
Swap	NYMEX	April - October 2012	90,000	$ 5.00	$ 34,310
Swap	NYMEX	Calendar 2012	300,000	$ 5.03	$ 196,075

Subsequent to December 31, 2011 and through February 10, 2012, the Company has entered into 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:

Type	Commodity Reference Price	Remaining Contract Period	Volume - MMBTU/Day	Average Price/MMBTU
Swap	NYMEX	April - December 2012	200,000	$ 3.02

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, 2011, 2010 and 2009 (refer to Note 2 for details of unrealized gains or losses included in accumulated other comprehensive income in the Consolidated Balance Sheets):

Natural Gas Commodity Derivatives:	For the Year Ended December 31, 2011	2010	2009
Realized gain on commodity derivatives(1)	$213,349	$116,827	$239,366
Unrealized gain (loss) on commodity derivatives(1)	100,383	208,625	(92,849)
Total gain on commodity derivatives	$313,732	$325,452	$146,517

(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, 2011.

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, 2011 and 2010, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2011. 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, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, the Company changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements as of December 31, 2009.

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, 2011, 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 17, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 17, 2012

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, 2011, 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, 2011, 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, 2011 and 2010 and the related consolidated statements of operations, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2011 of Ultra Petroleum Corp. and our report dated February 17, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 17, 2012

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2011	2010	2009
	(Amounts in thousands of U.S. dollars, except per share data)		
Revenues:			
Natural gas sales	$ 982,413	$886,396	$ 601,023
Oil sales	119,383	92,990	65,739
Total operating revenues	1,101,796	979,386	666,762
Expenses:			
Lease operating expenses	51,758	45,938	40,679
Production taxes	97,094	95,914	66,970
Gathering fees	56,511	50,126	45,155
Transportation charges	64,243	64,965	58,011
Depletion, depreciation and amortization	346,394	241,796	201,826
Write-down of proved oil and gas properties	—	—	1,037,000
General and administrative	26,032	24,351	19,772
Total operating expenses	642,032	523,090	1,469,413
Operating income (loss)	459,764	456,296	(802,651)
Other income (expense), net:			
Interest expense	(63,156)	(49,032)	(37,167)
Gain on commodity derivatives	313,732	325,452	146,517
Litigation expense	—	(9,902)	—
Other income (expense), net	532	260	(2,888)
Total other income (expense), net	251,108	266,778	106,462
Income (loss) before income tax provision (benefit)	710,872	723,074	(696,189)
Income tax provision (benefit)	257,670	258,615	(245,136)
Net income (loss)	$ 453,202	$464,459	$ (451,053)
Basic Earnings per Share:			
Net income (loss) per common share — basic	$ 2.97	$ 3.05	$ (2.98)
Fully Diluted Earnings per Share:			
Net income (loss) per common share — fully diluted	$ 2.94	$ 3.01	$ (2.98)
Weighted average common shares outstanding — basic	152,754	152,346	151,367
Weighted average common shares outstanding — fully diluted	154,336	154,253	151,367

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.

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ULTRA PETROLEUM CORP.

CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	(Amounts in thousands of U.S. dollars, except share data)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 11,307	$ 70,834
Restricted cash	121	98
Oil and gas revenue receivable	88,243	95,142
Joint interest billing and other receivables	82,370	48,561
Derivative assets	230,385	133,991
Inventory	1,164	2,760
Prepaid drilling costs and other current assets	6,330	9,663
Total current assets	419,920	361,049
Oil and gas properties, net, using the full cost method of accounting:		
Proved	3,651,622	2,589,423
Unproved	537,526	486,247
Property, plant and equipment	246,586	149,104
Long-term derivative assets	—	2,066
Deferred financing costs and other	14,051	7,726
Total assets	$4,869,705	$3,595,615
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 295,873	$ 210,311
Production taxes payable	62,117	53,382
Interest payable	30,306	26,878
Derivative liabilities	—	718
Deferred tax liabilities	73,380	42,685
Capital cost accrual	209,303	84,042
Total current liabilities	670,979	418,016
Long-term debt	1,903,000	1,560,000
Deferred income tax liabilities	635,009	420,711
Long-term derivative liabilities	—	5,337
Other long-term obligations	67,008	52,575
Commitments and contingencies (Note 12)		
Shareholders' equity:		
Common stock — no par value; authorized — unlimited; issued and outstanding — 152,476,564 and 152,567,813, at December 31, 2011 and 2010, respectively	463,221	426,779
Treasury stock	(14,951)	—
Retained earnings	1,145,439	712,197
Total shareholders' equity	1,593,709	1,138,976
Total liabilities and shareholders' equity	$4,869,705	$3,595,615

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

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

	Shares Issued and Outstanding	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Treasury Stock	Total Shareholders' Equity
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 earnings		—	(451,053)	—	—	(451,053)
Change in derivative instruments,						
Reclassification of derivative fair value into earnings, net of taxes	—	—	—	(15,577)	—	(15,577)
Total comprehensive earnings						(466,630)
Balances at December 31, 2009	151,759	$377,339	$ 281,383	$ —	$(10,525)	$ 648,197
Stock options exercised	1,206	6,561	—	—	—	6,561
Employee stock plan grants	105	4,841	—	—	—	4,841
Shares re-issued from treasury	—	(587)	(9,938)	—	10,525	—
Net share settlements	(502)	—	(23,707)	—	—	(23,707)
Fair value of employee stock plan grants	—	21,103	—	—	—	21,103
Tax benefit of stock options exercised	—	17,522	—	—	—	17,522
Net income	—	—	464,459	—	—	464,459
Balances at December 31, 2010	152,568	$426,779	$ 712,197	$ —	$ —	$1,138,976
Stock options exercised	672	9,928	—	—	—	9,928
Employee stock plan grants	150	—	—	—	700	700
Shares repurchased	(588)	—	—	—	(20,868)	(20,868)
Shares re-issued from treasury	—	(686)	(4,531)	—	5,217	—
Net share settlements	(325)	—	(15,429)	—	—	(15,429)
Fair value of employee stock plan grants	—	20,988	—	—	—	20,988
Tax benefit of stock options exercised	—	6,212	—	—	—	6,212
Net income	—	—	453,202	—	—	453,202
Balances at December 31, 2011	152,477	$463,221	$1,145,439	$ —	$(14,951)	$1,593,709

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2011	2010	2009
Cash provided by (used in):	(Amounts in thousands of U.S. dollars)		
Operating activities:			
Net income (loss) for the period	$ 453,202	$ 464,459	$ (451,053)
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depletion and depreciation	346,394	241,796	201,826
Write-down of proved oil and gas properties	—	—	1,037,000
Deferred and current non-cash income taxes	251,206	253,926	(253,966)
Unrealized (gain) loss on commodity derivatives	(100,383)	(208,625)	92,849
Excess tax benefit from stock based compensation	(6,212)	(17,522)	(14,213)
Stock compensation	13,919	12,944	10,901
Other	1,495	734	1,023
Net changes in operating assets and liabilities:			
Restricted cash	(23)	1,583	1,046
Accounts receivable	(26,910)	(31,966)	14,974
Other current assets	17	—	(2,913)
Prepaid expenses and other	(1,291)	(229)	4,268
Other non-current assets	—	(1,176)	(2,905)
Accounts payable and accrued liabilities	86,079	91,982	(38,079)
Production taxes payable	8,735	(7,439)	(596)
Interest payable	3,428	14,867	5,902
Other long-term obligations	433	6,035	(13,638)
Current taxes payable	3,203	3,359	215
Net cash provided by operating activities	1,033,292	824,728	592,641
Investing Activities:			
Acquisition of oil and gas properties	—	(403,806)	—
Oil and gas property expenditures	(1,435,611)	(1,164,389)	(673,518)
Gathering system expenditures	(83,996)	(76,703)	(67,833)
Proceeds from sale of oil and gas properties	5,821	68,420	—
Change in capital cost accrual	125,261	19,826	(56,327)
Restricted cash	—	28,257	(28,257)
Inventory	1,595	1,738	4,024
Purchase of property, plant and equipment	(21,865)	(2,442)	1,300
Net cash used in investing activities	(1,408,795)	(1,529,099)	(820,611)
Financing activities:			
Borrowings on long-term debt	1,257,000	1,000,000	817,000
Payments on long-term debt	(914,000)	(1,260,000)	(827,000)
Proceeds from issuance of Senior Notes	—	1,025,000	235,000
Deferred financing costs	(6,866)	(4,425)	(1,283)
Repurchased shares/net share settlements	(36,298)	(23,707)	(11,293)
Excess tax benefit from stock based compensation	6,212	17,522	14,213
Proceeds from exercise of options	9,928	6,561	1,430
Net cash provided by financing activities	315,976	760,951	228,067
(Decrease) increase in cash during the period	(59,527)	56,580	97
Cash and cash equivalents, beginning of period	70,834	14,254	14,157
Cash and cash equivalents, end of period	$ 11,307	$ 70,834	$ 14,254
SUPPLEMENTAL INFORMATION:			
Cash paid for:			
Interest	$ 88,964	$ 53,291	$ 30,579
Income taxes	$ 7,260	$ 2,537	$ 11,403

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

Ultra Petroleum Corp. (the "Company") is an independent oil and natural gas company engaged in the acquisition, exploration, development, and production of oil and natural gas properties. The Company is incorporated under the laws of 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. In addition, the Company has recently acquired acreage in eastern Colorado's Denver Julesburg 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. The Company presents its financial statements in accordance with U.S. Generally Accepted Accounting Principles ("GAAP"). All inter-company transactions and balances have been eliminated upon consolidation.

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

(c) *Restricted cash:* Restricted cash represents cash received by the Company from production sold where the final division of ownership of the production is unknown or in dispute. Wyoming law requires that these funds be held in a federally insured bank in Wyoming.

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

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.

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 results in a lower depletion, depreciation and amortization ("DD&A") rate in future periods. A write-down may not be reversed in future periods even though higher oil and natural gas prices may subsequently increase the ceiling.

(f) *Inventories:* Materials and supplies inventories are carried at lower of cost or market. 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, 2011, inventory of $1.2 million primarily includes the cost of pipe and production equipment that will be utilized during the 2012 drilling program.

(g) *Derivative instruments and hedging activities:* Currently, the Company largely relies on commodity derivative contracts to manage its exposure to commodity price risk. These commodity derivative contracts are typically referenced to natural gas index prices as published by independent third parties. 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"). The Company does not offset the value of its derivative arrangements with the same counterparty. (See Note 8).

(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, the Company recognizes the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit.

(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 income (loss) per common share:

	December 31,		
	2011	2010	2009
Net income (loss)	$453,202	$464,459	$(451,053)
Weighted average common shares outstanding during the period	152,754	152,346	151,367
Effect of dilutive instruments	1,582	1,907	—(1)
Weighted average common shares outstanding during the period including the effects of dilutive instruments	154,336	154,253	151,367
Net income (loss) per common share — basic	$ 2.97	$ 3.05	$ (2.98)
Net income (loss) per common share — fully diluted	$ 2.94	$ 3.01	$ (2.98)
Number of shares not included in dilutive earnings per share that would have been anti-dilutive because the exercise price was greater than the average market price of the common shares	1,030	1,214	—(1)

(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. See Note 9 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:* 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. 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, 2011 and 2010, the Company had a net natural gas imbalance liability of $1.3 million and $0.9 million, respectively.

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

(o) *Capitalized interest:* Interest is capitalized on the cost of unevaluated gas and oil properties that are excluded from amortization and actively being evaluated as well as on work in process relating to gathering systems that are not currently in service.

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

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

(r) *Recent accounting pronouncements:* In May 2011, the FASB issued ASU No. 2011-04, which amends FASB ASC 820. The amended guidance clarifies many requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements. Additionally, the amendments clarify the FASB’s intent about the application of existing fair value measurement requirements. The guidance provided in ASU No. 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The Company does not expect the adoption of this amendment to have a material impact on its consolidated financial statements.

2. OTHER COMPREHENSIVE INCOME:

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.

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Year Ended December 31,		
	2011	2010	2009
Net income (loss)	$453,202	$464,459	$(451,053)
Unrealized gain on derivative instruments*	—	—	(24,002)
Tax expense on unrealized gain on derivative instruments	—	—	8,425
Total comprehensive income (loss)	$453,202	$464,459	$(466,630)

* 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 8). 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.

3. ASSET RETIREMENT OBLIGATIONS:

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

	December 31,	
	2011	2010
Asset retirement obligations at beginning of period	$28,052	$17,372
Accretion expense	3,088	2,099
Liabilities incurred	10,878	8,564
Liabilities settled	(3)	(17)
Revisions of estimated liabilities	37	34
Asset retirement obligations at end of period	42,052	28,052
Less: current asset retirement obligations	—	—
Long-term asset retirement obligations	$42,052	$28,052

4. OIL AND GAS PROPERTIES:

	December 31, 2011	December 31, 2010
Developed Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	$ 5,974,604	$ 4,575,222
Less: Accumulated depletion, depreciation and amortization	(2,322,982)	(1,985,799)
	3,651,622	2,589,423
Unproven Properties:		
Acquisition and exploration costs not being amortized(1),(2)	537,526	486,247
Net capitalized costs — oil and gas properties	$ 4,189,148	$ 3,075,670

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

On a unit basis, DD&A from continuing operations was $1.41, $1.13 and $1.12 per Mcfe for the years ended December 31, 2011, 2010 and 2009, respectively.

(1) In 2010, a wholly-owned subsidiary of the Company acquired, for $403.8 million in cash, non-producing mineral acres and a small number of producing gas wells in the Pennsylvania Marcellus Shale. Additionally, the Company purchased additional undeveloped acreage in the Marcellus Shale for approximately $63.4 million during 2010.

(2) Interest is capitalized on the cost of unevaluated oil and natural gas properties that are excluded from amortization and actively being evaluated as well as on work in process relating to gathering systems that are not currently in service. For the years ended December 31, 2011 and 2010, total interest on outstanding debt was $93.9 million and $70.2 million, respectively, of which, $30.7 million and $21.2 million, respectively, was capitalized on the cost of unevaluated oil and natural gas properties and work in process relating to gathering systems that are not currently in service.

The Company holds interests in domestic projects in which costs related to these interests are not being depleted pending determination of existence of estimated proved reserves. The Company will continue to assess and allocate the unproven properties over the next several years as proved reserves are established and as exploration dictates whether or not future areas will be developed.

	Total	2011	2010	2009	Prior
Acquisition costs	$ 681,370	$ 69,330	$521,149	$ 36,432	$ 54,459
Exploration costs	22,439	3,364	2,985	2,829	13,261
Capitalized interest	48,084	28,474	19,610	—	—
Sales	(77,498)	(5,821)	(68,420)	(3,257)	—
Less transfers to proved	(136,869)	(44,068)	(44,621)	(36,004)	(12,176)
	$ 537,526	$ 51,279	$430,703	$ —	$ 55,544

5. PROPERTY, PLANT AND EQUIPMENT:

	December 31, 2011			2010
	Cost	Accumulated Depreciation	Net Book Value	Net Book Value
Gathering systems	$226,747	$ (7,736)	$219,011	$141,817
Computer equipment	2,426	(1,401)	1,025	993
Office equipment	444	(335)	109	124
Leasehold improvements	686	(379)	307	151
Land	22,150	—	22,150	2,437
Other	7,777	(3,793)	3,984	3,582
Property, Plant and Equipment, Net	$260,230	$ (13,644)	$246,586	$149,104

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 2010, the Company initiated service on its final two, of four total, 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. The condensate and water are transported to central points in the field where condensate can be loaded into trucks or delivered into pipelines for delivery to the Company’s customers.

Produced water is disposed of or recycled and re-used. At the end of 2011, more than 80% of the Company's operated condensate production in Wyoming was delivered from the Company's liquids gathering system directly into a pipeline, further reducing truck traffic and improving flow assurance as well as realized pricing.

In Pennsylvania, the Company and its partners continue 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 is expected to continue throughout 2012 allowing the Company to manage its midstream capacity to coincide with increased capacity requirements from its drilling activities. These facilities are gathering systems and related infrastructure, and their construction is expected to continue until the Company's properties in Pennsylvania are fully developed. To date, none of the Company's natural gas production in Pennsylvania has required processing, treating or blending in order to remove natural gas liquids or other impurities and it is anticipated that facilities of this type will not be required in the future to accommodate the Company's production.

6. LONG-TERM LIABILITIES:

	December 31, 2011	December 31, 2010
Bank indebtedness	$ 343,000	$ —
Senior notes	1,560,000	1,560,000
Other long-term obligations	67,008	52,575
	$ 1,970,008	$ 1,612,575

Aggregate maturities of debt at December 31, 2011:

2012	2013	2014	2015	2016	Beyond 5 years	Total
$—	$—	$—	$ 100,000	$ 405,000	$ 1,398,000	$ 1,903,000

Bank indebtedness. The Company (through its subsidiary, Ultra Resources) was a party to a revolving credit facility with a syndicate of banks led by JP Morgan Chase Bank, N.A. which was to mature in April 2012 (the "2007 Credit Agreement"). On October 6, 2011, in anticipation of the upcoming maturity of the 2007 Credit Agreement, the Company, through Ultra Resources (the "Borrower"), replaced the 2007 Credit Agreement in its entirety with a senior unsecured revolving credit facility with JP Morgan Chase Bank, N.A. as administrative agent, and the lenders party thereto (the "2011 Credit Agreement") and repaid all amounts outstanding under the 2007 Credit Agreement with proceeds of loans drawn under the 2011 Credit Agreement.

The 2011 Credit Agreement reflects an increased borrowing capacity as compared to the 2007 Credit Agreement with an initial loan commitment of $1.0 billion (which may be increased up to $1.25 billion at the request of the Borrower and with the lenders' consent), provides for the issuance of letters of credit of up to $250.0 million in aggregate, and matures in October 2016 (which term may be extended for up to two successive one-year periods at the Borrower's request and with the lenders' consent).

Loans under the 2011 Credit Agreement are unsecured and bear interest, at the Borrower's option, based on (A) a rate per annum equal to the prime rate or the weighted average fed funds rate on overnight transactions during the preceding business day plus 50 basis points, or (B) a base Eurodollar rate, substantially equal to the LIBOR rate, in either case plus a margin based on a grid of the Borrower's consolidated leverage ratio (for Eurodollar borrowings, 175 basis points per annum as of December 31, 2011). Payment of loans under the 2011

Credit Agreement are guaranteed by Ultra Petroleum Corp. and UP Energy Corporation. The Company also pays commitment fees on the unused commitment under the facility based on a grid of our consolidated leverage ratio.

The 2011 Credit Agreement contains typical and customary representations, warranties, covenants and events of default. The 2011 Credit Agreement includes restrictive covenants requiring the Borrower to maintain a consolidated leverage ratio of no greater than three and one half times to one and, as long as 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 no less than one and one half times to one. At December 31, 2011, the Company was in compliance with all of its debt covenants under the 2011 Credit Agreement.

Senior Notes: The Company's Senior Notes rank pari passu with the Company's 2011 Credit Agreement. Payment of the Senior Notes is guaranteed by Ultra Petroleum Corp. and UP Energy Corporation.

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, 2011, 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.

7. SHARE BASED COMPENSATION:

The Company sponsors a share based compensation plan: the 2005 Stock Incentive Plan (the "2005 Plan"). The plan is administered by the Compensation Committee of the Board of Directors (the "Committee"). The share based compensation plan is an important component of the total compensation package offered to the Company's key service providers, and reflects the importance that the Company places on motivating and rewarding superior results.

The 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. 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Valuation and Expense Information

	Year Ended December 31, 2011	2010	2009
Total cost of share-based payment plans	$21,688	$21,805	$18,872
Amounts capitalized in fixed assets	$ 7,769	$ 8,861	$ 7,971
Amounts charged against income, before income tax benefit	$13,919	$12,944	$10,901
Amount of related income tax benefit recognized in income	$ 4,997	$ 4,595	$ 3,826

Securities Authorized for Issuance Under Equity Compensation Plans

As of December 31, 2011, 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	1,459	$ 48.29	3,554
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	1,459	$ 48.29	3,554

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, 2011:

	Number of Options	Weighted Average Exercise Price (US$)		
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
Forfeited	(68)	$51.60	to	$76.01
Exercised	(1,206)	$ 1.49	to	$45.95
Balance, December 31, 2010	2,230	$ 3.91	to	$98.87
Forfeited	(99)	$51.60	to	$75.18
Exercised	(672)	$ 3.91	to	$33.57
Balance, December 31, 2011	1,459	$16.97	to	$98.87

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following tables summarize information about the stock options outstanding at December 31, 2011:

	Options Outstanding			
Range of Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Aggregate Intrinsic Value
$16.97 - $19.18	70	2.37	$ 17.44	$ 853
$25.08 - $55.58	637	3.60	$ 38.69	$ 179
$46.05 - $65.04	179	4.53	$ 56.67	$ —
$49.05 - $65.94	373	5.31	$ 54.58	$ —
$51.14 - $98.87	200	6.40	$ 70.51	$ —

	Options Exercisable			
Range of Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Aggregate Intrinsic Value
$16.97 - $19.18	70	2.37	$ 17.44	$ 853
$25.08 - $55.58	637	3.60	$ 38.69	$ 179
$46.05 - $65.04	179	4.53	$ 56.67	$ —
$49.05 - $65.94	373	5.31	$ 54.58	$ —
$51.14 - $98.87	200	6.40	$ 70.51	$ —

The aggregate intrinsic value in the preceding tables represents the total pre-tax intrinsic value, based on the Company's closing stock price of $29.63 on December 30, 2011, 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, 2011 was 0.1 million options.

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

	2011	2010	2009
Non-vested share options at beginning of year	$30.72	$26.28	$26.18
Non-vested share options at end of year	$ —	$30.72	$26.28
Options vested during the year	$30.73	$23.86	$25.07
Options forfeited during the year	$25.80	$28.36	$29.57

The fair value of stock options that vested during the years ended December 31, 2011, 2010 and 2009 was $6.4 million, $9.8 million and $3.9 million, respectively. The total intrinsic value of stock options exercised during the years ended December 31, 2011, 2010 and 2009 was $21.5 million, $50.7 million and $33.2 million, respectively.

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

PERFORMANCE SHARE PLANS:

Long Term Incentive Plans. The Company offers 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. In 2009, 2010 and 2011, the Compensation Committee (the "Committee") approved an award consisting of performance-based restricted stock units to be awarded to each participant.

For each LTIP award, the Committee establishes performance measures at the beginning of each performance period. 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 as a "target" value which corresponds to the number of shares of the Company's common stock the participant is eligible to receive if the target level for all performance measures is met. In addition, each participant is assigned threshold and maximum award levels in the event that actual performance is below or above target levels. For the 2009, 2010 and 2011 LTIP awards, the Committee established the following performance measures: return on equity, reserve replacement ratio, and production growth.

For the year ended December 31, 2011, the Company recognized $10.7 million in pre-tax compensation expense related to the 2009, 2010 and 2011 LTIP awards of restricted stock units. For the year ended December 31, 2010, the Company recognized $8.6 million in pre-tax compensation expense related to the 2008, 2009 and 2010 LTIP awards of restricted stock units. For the year ended December 31, 2009, the Company recognized $5.8 million in pre-tax compensation expense related to the 2007, 2008 and 2009 LTIP awards of restricted stock units. The amounts recognized during the year ended December 31, 2011 assumes that maximum performance objectives are attained. If the Company ultimately attains these performance objectives, the associated total compensation, estimated at December 31, 2011, for each of the three year performance periods is expected to be approximately $24.1 million, $12.0 million, and $12.1 million related to the 2009, 2010 and 2011 LTIP awards of restricted stock units, respectively. The 2008 LTIP Common Stock Award was paid in shares of the Company's stock to employees during the first quarter of 2011 and totaled $4.3 million (41,443 net shares).

8. 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.

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. The Company's board approved hedging greater than 50% of the Company's forecast 2011 production.

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 provided operational flexibility to curtail gas production in the event of 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 settlements for production months through December 2010.

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The natural gas reference prices of these commodity derivative contracts are typically referenced to natural gas index prices as published by independent third parties or natural gas futures settlement prices as traded on the NYMEX.

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

At December 31, 2011, 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 9 for the detail of the asset and liability values of the following derivatives. The Board has approved our hedging greater than 50% of our forecast 2012 production.

Type	Commodity Reference Price	Remaining Contract Period	Volume - MMBTU/Day	Average Price/MMBTU	Fair Value - December 31, 2011
					Asset
Swap	NYMEX	April - October 2012	90,000	$ 5.00	$ 34,310
Swap	NYMEX	Calendar 2012	300,000	$ 5.03	$ 196,075

Subsequent to December 31, 2011 and through February 10, 2012, the Company has entered into 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:

Type	Commodity Reference Price	Remaining Contract Period	Volume - MMBTU/Day	Average Price/MMBTU
Swap	NYMEX	April - December 2012	200,000	$ 3.02

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table summarizes the pre-tax realized and unrealized gains and losses the Company recognized related to its natural gas derivative instruments in the Consolidated Statements of Operations for the years ended December 31, 2011, 2010 and 2009 (refer to Note 2 for details of unrealized gains or losses included in accumulated other comprehensive income in the Consolidated Balance Sheets):

	For the Year Ended December 31,		
	2011	2010	2009
Natural Gas Commodity Derivatives:			
Realized gain on commodity derivatives(1)	$213,349	$116,827	$239,366
Unrealized gain (loss) on commodity derivatives(1)	100,383	208,625	(92,849)
Total gain on commodity derivatives	$313,732	$325,452	$146,517

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

9. 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, 2011. The company has no derivative instruments which qualify for cash flow hedge accounting.

	Level 1	Level 2	Level 3	Total
Assets:				
Current derivative asset	$ —	$230,385	$ —	$230,385

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.

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 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.

	December 31, 2011		December 31, 2010	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-Term Debt:				
5.45% Notes due 2015, issued 2008	$ 100,000	$ 111,475	$ 100,000	$ 108,572
7.31% Notes due 2016, issued 2009	62,000	74,817	62,000	72,153
4.98% Notes due 2017, issued 2010	116,000	128,570	116,000	119,385
5.92% Notes due 2018, issued 2008	200,000	231,091	200,000	212,660
7.77% Notes due 2019, issued 2009	173,000	219,552	173,000	203,051
5.50% Notes due 2020, issued 2010	207,000	229,423	207,000	206,233
4.51% Notes due 2020, issued 2010	315,000	318,925	315,000	284,207
5.60% Notes due 2022, issued 2010	87,000	94,165	87,000	84,818
4.66% Notes due 2022, issued 2010	35,000	34,631	35,000	30,989
5.85% Notes due 2025, issued 2010	90,000	99,022	90,000	87,211
4.91% Notes due 2025, issued 2010	175,000	173,835	175,000	152,064
Credit Facility	343,000	343,000	—	—
	$ 1,903,000	$ 2,058,506	$ 1,560,000	$ 1,561,343

10. INCOME TAXES:

The consolidated income tax provision is comprised of the following:

	Year Ended December 31,		
	2011	2010	2009
Current	$ 6,464	$ 4,763	$ 8,830
Current tax benefit on equity compensation	6,212	17,522	14,213
Total current tax	12,676	22,285	23,043
Deferred	244,994	236,330	(268,179)
Total income tax provision (benefit)	$257,670	$258,615	$(245,136)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The income tax provision (benefit) 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:

	Year Ended December 31,		
	2011	2010	2009
Income tax provision (benefit) computed at the U.S. statutory rate	$248,805	$253,076	$(243,666)
State income tax provision (benefit) net of federal benefit	6,329	3,608	(698)
Canadian net operating loss valuation allowance	—	(677)	—
Tax effect of rate change	4,228	1,939	—
Other, net	(1,692)	669	(772)
	$257,670	$258,615	$(245,136)

The tax effects 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,	
	2011	2010
Deferred tax assets — current:		
Derivative instruments, net	$ —	$ 255
Incentive compensation/other, net	9,329	4,627
Net deferred tax assets — current	$ 9,329	$ 4,882
Deferred tax liabilities — current:		
Derivative instruments, net	$ 82,709	$ 47,567
Net deferred tax liabilities — current	$ 82,709	$ 47,567
Net deferred tax liability — current	$ 73,380	$ 42,685
Deferred tax assets — non-current:		
U.S. federal tax credit carryforwards	13,280	13,714
Capital loss carryforwards	1,929	—
Derivative instruments, net	—	1,161
Incentive compensation/other, net	13,030	14,745
	28,239	29,620
Valuation allowance — Foreign Tax Credit (FTC)	(1,692)	(1,692)
Valuation allowance (Capital loss carryforwards)	(1,929)	—
Net deferred tax assets — non-current	$ 24,618	$ 27,928
Deferred tax liabilities — non-current:		
Property and equipment	659,040	448,298
Other	587	341
Net non-current tax liabilities	$659,627	$448,639
Net non-current tax liability	$635,009	$420,711

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, 2011.

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.

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.

The Company files a consolidated federal income tax return in the United States federal jurisdiction and various combined, consolidated, unitary, and separate filings in several states, and international jurisdictions. With certain exceptions, the 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 2008.

As of December 31, 2011, the Company had approximately $11.6 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, 2011, the Company has $1.7 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 had an unutilized capital loss carryforward of approximately $5.4 million as of December 31, 2011. The majority of this carryforward expires in 2013. Due to the unpredictability of future capital gains that would allow for the utilization of this carryforward, a valuation allowance has be placed on the full amount of the carryforward.

The Company had Canadian net operating loss carryforwards of approximately $2.7 million as of December 31, 2009. The unexpired portion of the Canadian net operating loss carryforward was fully utilized in 2010, and thus the valuation allowance at December 31, 2009 has been removed and no deferred tax asset related to the Canadian net operating loss exists as of December 31, 2010.

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, 2011 and 2010, the Company also recorded a total deferred tax liability of $82.7 million and $46.2 million, respectively, attributable to the unrealized gains and losses recorded in the statement of operations.

11. 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 100% of the employee's contribution up to 5% of compensation, as defined by the plan, along with an employer discretionary contribution of 8%. The expense associated with the Company's contribution was $1.4 million, $1.2 million and $1.1 million for the years ended December 31, 2011, 2010 and 2009, respectively.

12. COMMITMENTS AND CONTINGENCIES:

Transportation contract. The Company is an anchor shipper on REX securing pipeline infrastructure providing sufficient capacity to transport a portion of its natural gas production away from southwest Wyoming and to provide for reasonable basis differentials for its natural gas in the future. REX begins at the Opal Processing Plant in southwest Wyoming and traverses Wyoming and several other states to an ultimate terminus in eastern Ohio. The Company's commitment involves a capacity of 200 MMMBtu per day of natural gas for a term of 10-years commencing in November 2009, 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.

Subsequently, 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 $776.3 million.

Drilling contracts. As of December 31, 2011, the Company had committed to drilling obligations with certain rig contractors totaling $60.5 million ($45.5 million due in 2012, $15.0 million due in 2013). The commitments expire in 2013 and were entered into to fulfill the Company's drilling program initiatives in Wyoming.

Office space lease. The Company's maintains office space in Colorado, Texas, Wyoming and Pennsylvania with total remaining commitments for office leases of $2.5 million at December 31, 2011 ($1.0 million in 2012, $1.5 million in 2013 to 2015).

During the years ended December 31, 2011, 2010 and 2009, the Company recognized expense associated with its office leases in the amount of $0.9 million, $0.8 million, and $0.9 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

13. CONCENTRATION OF CREDIT RISK:

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

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

The Company maintains credit policies intended to monitor and mitigate the risk of uncollectible accounts receivable related to the sale of natural gas, condensate as well as its commodity derivative positions. The Company performs a credit analysis of each of its customers and counterparties prior to making any sales to new customers or extending additional credit to existing customers. Based upon this credit analysis, the Company may require a standby letter of credit or a financial guarantee. The Company did not have any outstanding, uncollectible accounts for its natural gas or condensate sales, nor derivative settlements sales at December 31, 2011.

A significant counterparty is defined as one that individually accounts for 10% or more of the Company's total revenues during the year. In 2011, the Company had no single customer that represented 10% or more of its total revenues.

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 through which their financial statements are evaluated for subsequent events in both issued and revised financial statements. The Company has evaluated the period subsequent to December 31, 2011 for events that did not exist at the balance sheet date but arose after that date and determined that no subsequent events arose that should be disclosed in order to keep the financial statements from being misleading.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

15. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED):

	2011				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Revenues from continuing operations	$257,290	$ 280,567	$293,141	$270,798	$1,101,796
Gain on commodity derivatives	15,635	47,606	114,166	136,325	313,732
Expenses from continuing operations	145,666	151,365	160,543	184,458	642,032
Interest expense	14,590	15,590	15,902	17,074	63,156
Other income (expense), net	20	(4)	(3)	519	532
Income before income tax provision	112,689	161,214	230,859	206,110	710,872
Income tax provision	43,969	57,709	81,713	74,279	257,670
Net income	$ 68,720	$ 103,505	$149,146	$131,831	$ 453,202
Net income per common share — basic	$ 0.45	$ 0.68	$ 0.98	$ 0.86	$ 2.97
Net income per common share — fully diluted	$ 0.44	$ 0.67	$ 0.97	$ 0.86	$ 2.94

	2010				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Revenues from continuing operations	$273,124	$ 228,388	$240,374	$237,500	$ 979,386
Gain (loss) on commodity derivatives	181,351	14,566	150,186	(20,651)	325,452
Expenses from continuing operations	124,260	125,999	128,489	144,342	523,090
Interest expense	11,718	11,437	11,382	14,495	49,032
Litigation expense	—	9,902	—	—	9,902
Other (expense) income , net	151	22	12	75	260
Income before income tax provision	318,648	95,638	250,701	58,087	723,074
Income tax provision	116,272	34,145	88,059	20,139	258,615
Net income	$202,376	$ 61,493	$162,642	$ 37,948	$ 464,459
Net income per common share — basic	$ 1.33	$ 0.40	$ 1.07	$ 0.25	$ 3.05
Net income per common share — fully diluted	$ 1.31	$ 0.40	$ 1.05	$ 0.25	$ 3.01

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. SEC Release No. 33-8995, amends 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 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.

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Our policies and practices regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and gas reserves quantities and present values in compliance with the SEC's regulations and GAAP. The Vice President — Reservoir Engineering & Development is primarily responsible for overseeing the preparation of the Company's reserve estimates by our independent engineers, Netherland, Sewell & Associates, Inc. The Vice President – Reservoir Engineering & Development has a Bachelor and Master of Science degree in Petroleum Engineering and is a licensed Professional Engineer with over 17 years of experience. The Company's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation.

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 Company's proved undeveloped reserves are limited to economic locations that are scheduled in accordance with the Company's current planning and budgeting process. The inventory of bookable locations available to the Company is substantially larger than the amount ultimately included in the Company's year-end reserves. From time to time, the Company may adjust the inventory and schedule of its proved undeveloped locations in response to changes in capital budget, economics, new opportunities in the portfolio or resource availability. The Company has not scheduled any proved undeveloped reserves beyond five years nor does it have any proved undeveloped locations that have been part of its inventory of proved undeveloped locations for over five years.

The 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.

In estimating proved reserves and future revenue as of December 31, 2011, the Company's independent reserve engineer, Netherland, Sewell & Associates, Inc., used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The reserves were estimated using deterministic methods; these estimates were prepared in accordance with generally accepted petroleum engineering and evaluation principles. Standard engineering and geoscience methods, such as performance analysis, volumetric analysis and analogy, that were considered to be appropriate and necessary to establish reserve quantities and reserve categorization that conform to SEC definitions and guidelines, were also used. In evaluating the information at their disposal, Netherland, Sewell & Associates, Inc. excluded from their consideration all matters as to which the controlling interpretation may be legal or accounting, rather than engineering and geoscience. As in all aspects of oil and natural gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, Netherland, Sewell & Associates, Inc.'s conclusions necessarily represent only informed professional judgment.

The following unaudited tables as of December 31, 2011, 2010, and 2009 are based upon estimates prepared by Netherland, Sewell & Associates, Inc. in reports dated February 1, 2012, January 31, 2011, and January 27, 2010, respectively. 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, 2011, 2010 and 2009. All such reserves are located in the Green River Basin in Wyoming and the Appalachian Basin of Pennsylvania.

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Since January 1, 2011, 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	
	Oil (MBbls)	Natural Gas (MMcf)
Reserves, December 31, 2008	27,007	3,355,788
Extensions, discoveries and additions	5,902	758,659
Production	(1,320)	(172,189)
Revisions	(2,404)	(205,657)
Reserves, December 31, 2009	29,185	3,736,601
Extensions, discoveries and additions	7,369	1,055,047
Production	(1,334)	(205,613)
Revisions	(3,536)	(385,880)
Reserves, December 31, 2010	31,684	4,200,155
Extensions, discoveries and additions	4,592	1,112,147
Production	(1,408)	(236,832)
Revisions	(1,787)	(296,916)
Reserves, December 31, 2011	33,081	4,778,554

	United States	
	Oil (MBbls)	Natural Gas (MMcf)
Proved:		
Developed	11,462	1,412,562
Undeveloped	15,546	1,943,225
Total Proved — 2008	27,007	3,355,788
Developed	11,627	1,541,813
Undeveloped	17,558	2,194,788
Total Proved — 2009	29,185	3,736,601
Developed	11,013	1,678,697
Undeveloped	20,671	2,521,458
Total Proved — 2010	31,684	4,200,155
Developed	11,794	1,973,391
Undeveloped	21,287	2,805,163
Total Proved — 2011	33,081	4,778,554

During 2011, substantially all of our extensions and discoveries in the proved developed category were attributable to wells drilled in 2011, and substantially all of our extensions and discoveries in the proved undeveloped category were attributable to our ongoing drilling activities and its associated effect on our proved undeveloped reserves estimates.

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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, 2011, 2010 and 2009 was $4.035, $4.05 and $3.04 per Mcf, respectively, for natural gas and $88.19, $68.93 and $52.18 per barrel, respectively, for condensate, based upon the average of the price in effect on the first day of the month for the preceding twelve month period.

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

	As of December 31,		
	2011	2010	2009
Future cash inflows	$ 22,196,913	$ 19,186,072	$ 12,870,816
Future production costs	(6,113,282)	(5,253,509)	(3,916,222)
Future development costs	(4,294,375)	(3,052,843)	(2,249,993)
Future income taxes	(3,340,516)	(3,198,413)	(1,998,114)
Future net cash flows	8,448,740	7,681,307	4,706,487
Discount at 10%	(4,652,684)	(4,155,739)	(2,679,787)
Standardized measure of discounted future net cash flows	$ 3,796,056	$ 3,525,568	$ 2,026,700

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,		
	2011	2010	2009
Standardized measure, beginning	$3,525,568	$2,026,700	$ 3,017,686
Net revisions of previous quantity estimates	(446,677)	(592,919)	(216,946)
Extensions, discoveries and other changes	1,654,793	1,601,154	782,763
Changes in future development costs	(741,658)	(606,449)	(103,056)
Sales of oil and gas, net of production costs	(896,434)	(787,409)	(513,958)
Net change in prices and production costs	108,108	1,501,002	(1,772,644)
Development costs incurred during the period that reduce future development costs	464,880	404,402	395,092
Accretion of discount	499,358	288,713	444,387
Net changes in production rates and other	(338,982)	297,957	(572,380)
Net change in income taxes	(32,900)	(607,583)	565,756
Aggregate changes	270,488	1,498,868	(990,986)
Standardized measure, ending	$3,796,056	$3,525,568	$ 2,026,700

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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,		
	2011	2010	2009
United States			
Acquisition costs — unproved properties, net	$ 91,983	$ 472,339	$ 33,176
Exploration	48,998	249,029	102,217
Development	1,372,805	855,110	605,958
Total	$1,513,786	$1,576,478	$741,351

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

	Years Ended December 31,		
	2011	2010	2009
United States			
Oil and gas revenue	$1,101,796	$ 979,386	$ 666,762
Production expenses	(205,363)	(191,978)	(152,804)
Depletion and depreciation	(346,394)	(241,796)	(201,826)
Write-down of proved oil and gas properties	—	—	(1,037,000)
Income taxes	(197,464)	(193,692)	254,429
Total	$ 352,575	$ 351,920	$ (470,439)

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

	December 31,	
	2011	2010
Developed Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	$ 5,974,604	$ 4,575,222
Less: accumulated depletion, depreciation and amortization	(2,322,982)	(1,985,799)
	3,651,622	2,589,423
Unproven Properties:		
Acquisition and exploration costs not being amortized	537,526	486,247
	$ 4,189,148	$ 3,075,670

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

None.

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

Management's Report on Internal Control Over Financial Reporting

Management's Report on Internal Control Over Financial Reporting is included on page 52 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, 2011 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, 2011. 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, 2011.

The Company has adopted a code of ethics that applies to the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. The full text of such code of ethics is posted on the Company's website at www.ultrapetroleum.com, and is available free of charge in print to any shareholder who requests it. Requests for copies should be addressed to the Secretary at 400 North Sam Houston Parkway East, Suite 1200, Houston, Texas 77060.

Item 11. ***Executive Compensation.***

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement, which will be filed not later than 120 days after December 31, 2011.

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

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement, which will be filed not later than 120 days after December 31, 2011.

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, 2011.

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, 2011.

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 October 6, 2011 among Ultra Resources, Inc., JPMorgan Chase Bank, N.A. as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed on October 11, 2011).
10.2	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).
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).

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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	Third Supplement dated October 12, 2010 to Master Note Purchase Agreement dated March 6, 2008 (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed on October 12, 2010).
10.13	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).
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 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, 2011.
*101.INS	XBRL Instance Document
*101.SCH	XBRL Taxonomy Extension Schema Document
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
*101.LAB	XBRL Taxonomy Extension Label Linkbase Document
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
*101.DEF	XBRL Taxonomy Extension Definition

* Filed herewith.

SIGNATURES

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

ULTRA PETROLEUM CORP.

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

Date: February 17, 2012

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 17, 2012
/s/ Marshall D. Smith Marshall D. Smith	Senior Vice President and Chief Financial Officer (principal financial officer)	February 17, 2012
/s/ Garland R. Shaw Garland R. Shaw	Corporate Controller (principal accounting officer)	February 17, 2012
/s/ W. Charles Helton W. Charles Helton	Director	February 17, 2012
/s/ Stephen J. McDaniel Stephen J. McDaniel	Director	February 17, 2012
/s/ Roger A. Brown Roger A. Brown	Director	February 17, 2012

EXHIBIT INDEX

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*101.SCH	XBRL Taxonomy Extension Schema Document
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*101.LAB	XBRL Taxonomy Extension Label Linkbase Document
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
*101.DEF	XBRL Taxonomy Extension Definition

* Filed herewith.

Exhibit 23.1

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

Netherland, Sewell & Associates, Inc. has issued a report, as of December 31, 2011, of the "Estimate of Reserves and Future Revenue to the Ultra Petroleum Corporation Interest in Certain Gas Properties Prepared in Accordance with Securities and Exchange Commission Regulations" for Ultra Petroleum Corp. Netherland, Sewell & Associates, Inc. consents to the reference in Form 10-K to Netherland, Sewell & Associates, Inc.'s reserves report dated February 1, 2012, and to the incorporation by reference of our Firm's name and report into Ultra's previously filed Registration Statements on Form S-8 (File Nos. 333-132443; 333-13342; 333-13278) and Form S-3 (File Nos. 333-89522; 333-162062).

NETHERLAND, SEWELL & ASSOCIATES, INC.

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

Dallas, Texas
February 17, 2012

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-8 No. 333-13342) pertaining to the Ultra Petroleum Corp. 1998 Stock Option Plan,

(2) Registration Statement (Form S-8 No. 333-13278) pertaining to the Ultra Petroleum Corp. 2000 Stock Incentive Plan,

(3) Registration Statement (Form S-8 No. 333-132443) pertaining to the Ultra Petroleum Corp. 2005 Stock Incentive Plan,

(4) Registration Statement (Form S-3 No. 333-162062) of Ultra Petroleum Corp.;

of our reports dated February 17, 2012, with respect to the consolidated financial statements of Ultra Petroleum Corp. and the effectiveness of internal control over financial reporting of Ultra Petroleum Corp. included in this Annual Report (Form 10-K) of Ultra Petroleum Corp. for the year ended December 31, 2011.

Houston, Texas
February 17, 2012

Exhibit 31.1

CERTIFICATION

I, Michael D. Watford, certify that:

1. I have reviewed this Annual Report on Form 10-K of Ultra Petroleum Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

/s/ Michael D. Watford

Michael D. Watford,
Chairman, President and Chief Executive Officer (Principal Executive Officer)

Date: February 17, 2012

Exhibit 31.2

CERTIFICATION

I, Marshall D. Smith, certify that:

1. I have reviewed this Annual Report on Form 10-K of Ultra Petroleum Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

/s/ Marshall D. Smith

Marshall D. Smith,
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: February 17, 2012

EXHIBIT 32.1

SECTION 906 CERTIFICATION PURSUANT OF PRINCIPAL EXECUTIVE OFFICER
ULTRA PETROLEUM CORP.

In connection with the Annual Report of Ultra Petroleum Corp. (the ***"Company"***) on Form 10-K for the fiscal year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the ***"Report"***), I, Michael D. Watford, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Michael D. Watford
Michael D. Watford,
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

Dated: February 17, 2012

This certification is being furnished as an exhibit to the Report pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, will not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This certification will not be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent that the Company specifically incorporates it by reference.

Exhibit 32.2

SECTION 906 CERTIFICATION PURSUANT OF PRINCIPAL FINANCIAL OFFICER
ULTRA PETROLEUM CORP.

In connection with the Annual Report of Ultra Petroleum Corp. (the ***"Company"***) on Form 10-K for the fiscal year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the ***"Report"***), I, Marshall D. Smith, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Marshall D. Smith
Marshall D. Smith,
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Dated: February 17, 2012

This certification is being furnished as an exhibit to the Report pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, will not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This certification will not be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent that the Company specifically incorporates it by reference.

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

February 1, 2012

Mr. Brad Johnson
Ultra Petroleum Corporation
304 Inverness Way South, Suite 295
Englewood, Colorado 80112

Dear Mr. Johnson:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2011, to the Ultra Petroleum Corporation (Ultra) interest in certain gas properties located in Pennsylvania and Wyoming. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Ultra. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Ultra's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Ultra interest in these properties, as of December 31, 2011, to be:

	Net Reserves		Future Net Revenue (M$)	
Category	Gas (MMCF)	Condensate (MBBL)	Total	Present Worth at 10%
Proved Developed Producing	1,827,709	11,605	5,661,382	3,295,455
Proved Developed Non-Producing	145,682	189	346,903	198,303
Proved Undeveloped	2,805,162	21,288	5,780,971	1,803,205
Total Proved	4,778,554	33,081	11,789,256	5,296,964

Totals may not add because of rounding.

Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases. Condensate volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons.

The estimates shown in this report are for proved reserves. As requested, probable and possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is Ultra's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Ultra's share of production taxes and ad valorem taxes, capital costs, abandonment costs, and operating expenses but before

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consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2011. For gas volumes for the Wyoming properties, the average Kern River (Opal plant) spot price of $3.959 per MMBTU is adjusted for energy content, fuel usage, and fees for gathering and processing. For gas volumes for the Pennsylvania properties, the average Dominion (South Point) spot price of $4.243 per MMBTU is adjusted for energy content and fees for gathering and processing. For condensate volumes, the average West Texas Intermediate spot price of $96.19 per barrel is reduced by $8.00 to reflect contract adjustments for quality and fees for gathering and treating. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $4.035 per MCF of gas and $88.19 per barrel of condensate.

Operating costs used in this report are based on operating expense records of Ultra. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Headquarters general and administrative overhead expenses of Ultra are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are held constant throughout the lives of the properties.

Capital costs used in this report were provided by Ultra and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of Ultra's future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Ultra's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are held constant to the date of expenditure.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential gas volume and value imbalances resulting from overdelivery or underdelivery to the Ultra interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Ultra receiving its net revenue interest share of estimated future gross gas production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for non-producing zones, undeveloped locations, and producing wells that lack sufficient production history upon which performance related estimates of reserves can be based; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Ultra, other interest owners, various operators of the properties, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting geoscience, performance, and work data are on file in our office. The titles to the properties have not been examined by NSAI, nor has the actual degree or type of interest owned been independently confirmed. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Robert C. Barg
Robert C. Barg, P.E. 71658
Senior Vice President

Date Signed: February 1, 2012

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

Date Signed: February 1, 2012

RCB:KDP

DEFINITIONS OF OIL AND GAS RESERVES

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

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

DEFINITIONS OF OIL AND GAS RESERVES

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

> *Supplemental definitions from the 2007 Petroleum Resources Management System:*
>
> *Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.*
>
> *Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.*

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well.* A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible.* The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR).* Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before

acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or “G&G” costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well.* An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

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

(15) *Field.* An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas (“oil and gas”) in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a “terminal point”, which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

DEFINITIONS OF OIL AND GAS RESERVES

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

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

DEFINITIONS OF OIL AND GAS RESERVES

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

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

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

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire,

unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

  (A) The area identified by drilling and limited by fluid contacts, if any, and
  (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

  (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
  (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

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

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

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

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

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

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

DEFINITIONS OF OIL AND GAS RESERVES

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

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

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

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

From the SEC’s Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company’s level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company’s historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.