ULTRA PETROLEUM CORP
Form 10-K
February 26, 2008

Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
	For the Fiscal Year ended December 31, 2007
o	**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: 0-29370
Ultra Petroleum Corp.
(Exact Name of Registrant as Specified in Its Charter)

Yukon Territory, Canada	**N/A**
(Jurisdiction of Incorporation or Organization)	*(I.R.S. Employer Identification No.)*

363 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 þ NO o

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 o NO þ

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 requirement for the past 90 days. YES þ NO o

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. þ

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 þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was approximately $8,390,514,190 as of June 29, 2007 (based on the last reported sales price of $55.24 of such stock on the American Stock Exchange on such date).

As of February 15, 2008, there were 152,437,606 common shares of the registrant outstanding.

Documents incorporated by reference: The definitive Proxy Statement for the 2008 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2007, is incorporated by reference in Part III of this Form 10-K.

TABLE OF CONTENTS

Table of Contents

Certain Definitions

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

Bbl One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or other liquid hydrocarbons.

Bcf One billion cubic feet of natural gas.

Bcfe One billion cubic feet of natural gas equivalent.

BOE One barrel of oil equivalent, converting natural gas to oil at the ratio of 6 Mcf of natural gas to 1 Bbl of oil.

BTU British Thermal Unit.

Condensate An oil-like liquid produced in association with natural gas production that condenses from natural gas as it is produced and delivered into a separator or similar equipment and collected in tanks at each well prior to the delivery of such natural gas to the natural gas gathering pipeline system.

MBbl One thousand barrels.

Mcf One thousand cubic feet of natural gas.

Mcfe One thousand cubic feet of natural gas equivalent, converting oil or condensate to natural gas at the ratio of 1 Bbl of oil or condensate to 6 Mcf of natural gas.

MMBbl One million barrels of 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 pre-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 on the last day of the year, 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:

Proved oil and natural gas reserves. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made as defined in Rule 4-10(a)(2). Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(a) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (1) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(b) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(c) Estimates of proved reserves do not include the following: (1) oil that may become available from known reservoirs but is classified separately as indicated additional reserves ; (2) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (3) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (4) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed reserves Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods as defined in Rule 4-10(a)(3).

Proved undeveloped reserves Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required as defined in Rule 4-10(a)(4).

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

Working interest A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and natural gas. A working interest owner who owns a portion of the working interest may participate either as operator or by voting his percentage interest to approve or disapprove the appointment of an operator and drilling and other major activities in connection with the development and operation of a property.

Terms used to describe seismic operations

Seismic data Oil and natural gas companies use seismic data as their principal source of information to locate oil and natural gas deposits, both to aid in exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geophones which digitize and record the reflected waves. Computers are then used to process the raw data to develop an image of underground formations.

2-D seismic data 2-D seismic survey data has been the standard acquisition technique used to image geologic formations over a broad area. 2-D seismic data is collected by a single line of energy sources which reflect seismic waves to a single line of geophones. When processed, 2-D seismic data produces an image of a single vertical plane of sub-surface data.

3-D seismic data 3-D seismic data is collected using a grid of energy sources, which are generally spread over several miles. A 3-D survey produces a three dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is generally considered a more reliable indicator of potential oil and natural gas reservoirs in the area evaluated.

PART I

Item 1. *Business.*

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 originally 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 in the Green River Basin of southwest Wyoming. The Company continually evaluates other opportunities for the acquisition, exploration and development of oil and natural gas properties.

Ultra s current operations are focused on developing and expanding its position in a tight gas sand trend located in the Green River Basin in southwest Wyoming. As of December 31, 2007, Ultra owns interests in approximately 121,652 gross (62,756 net) acres in Wyoming covering approximately 230 square miles. The Company owns an interest in approximately 676 gross producing wells in this area and is operator of approximately 50% of the 676 gross wells. The Company also has an exploration effort underway in Pennsylvania.

Following the acquisition of Pendaries Petroleum Ltd. (Pendaries) on January 16, 2001, the Company became active in oil and natural gas exploration and development covering the 04/36 Block and the 05/36 Block (jointly the Blocks) in Bohai Bay, China. During the third quarter of 2007, we made the decision to dispose of Sino-American Energy Corporation (Sino-American), which owned our Bohai Bay assets in China, in order to focus on our legacy asset in the Pinedale Field in southwest Wyoming. The reserve volumes sold represent all of Ultra s international assets and, previously, were the only results included in our foreign operating segment.

On September 26, 2007, Ultra Petroleum Corp. s wholly-owned subsidiary, UP Energy Corporation, a Nevada corporation, entered into a definitive share purchase agreement with an effective date of June 30, 2007 and a closing date of October 22, 2007, to sell all of the outstanding shares of Sino-American, a Texas corporation, for a total purchase price of US$223.0 million, subject to adjustments. Sino-American held all of Ultra Petroleum Corp. s interests in oil and gas production sharing contracts in Bohai Bay, China. The purchaser was SPC E&P (China) Pte. Ltd., a wholly-owned subsidiary of Singapore Petroleum Company. See Note 11 for further discussion on the completion of the sale.

The Company also owns interests in 252,629 gross (140,100 net) acres in Pennsylvania. The Company drilled one gross (1.0 net) test well on this acreage in 2005. During 2006, this well was brought on production and the Company commenced drilling operations on two gross (1.12 net) additional exploratory wells in the area. At year end 2006, one well remained drilling while the second well was suspended. During 2007, the Company drilled one gross (1.0 net) well on which completion operations were ongoing at December 31, 2007. Subsequent to year end 2007, this well was temporarily abandoned. Ultra continues to evaluate this area to determine plans for future activity.

Table of Contents

The Company s annual report on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K, as well as any amendments to such reports and all other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available free of charge to the public on the Company s website at www.ultrapetroleum.com. To access the Company s SEC filings, select Financials under the Investor Relations tab on the Company s website. You may also request a copy of these filings at no cost by making written or telephone requests for copies to Ultra Petroleum Corp., Manager, Investor Relations, 363 N. Sam Houston Pkwy. E., Suite 1200, Houston, TX 77060, (281) 876-0120.

Any materials that the Company has filed with the SEC may be read and/or copied at the SEC s Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding us. The SEC s website address is www.sec.gov.

Business Strategy

Green River Basin, Wyoming

In 2008, the Company plans to continue its ongoing program to identify, develop and explore the acreage position now held in the tight gas sand trend in the Green River Basin in southwest Wyoming. The Company expects that the majority of the wells drilled during 2008 will target 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. The Company plans to drill delineation, step-out and exploration wells on its Green River Basin acreage positions in an ongoing attempt to further define and expand the current known producing limits of these two field areas. Work is continuing in an effort to assess the need for further increased density drilling to more efficiently recover the vast resources present in the area. Currently, the Pinedale field is approved by the WOGCC for a mix of well densities ranging from one well per 40-acre government quarter section (40-acre equivalent) down to 16 wells per government quarter section (10-acre equivalent). Pilot areas have been approved for testing of well density of 32 wells per government quarter section (5-acre equivalent) with results expected during 2008. In the Jonah field, the current spacing 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). In addition to the ongoing efforts in the Lance Pool section, the Company is continuing to drill a deep test to further evaluate the potential for production from the Rock Springs, Blair and Hilliard Formations which underlie much of the Company s acreage position in the Pinedale field. All of the Company s drilling activity is conducted utilizing its extensive integrated geological and geophysical data set. This data set is being utilized to map the potentially productive intervals, to identify areas for future extension of the Lance fairway and to identify deeper objectives which may warrant drilling.

Pennsylvania

The Company has drilled three test wells in the Marshlands prospect area to date. During 2008 the Company plans to drill or participate in approximately 12 wells in the Marshlands prospect to test the Devonian, Marcellus Shale formation. Ultra plans to continue to evaluate its acreage holding in the area, acquire additional acreage, seismic and geologic data in the area as needed, and develop an overall strategy to assess the potential of the area and bring that potential to production in a timely and cost effective manner.

Bohai Bay, China

On October 22, 2007, the Company closed on the sale of Sino-American, which owned our Bohai Bay assets in China, in order to focus on our legacy asset in the Pinedale Field in southwest Wyoming. See Note 11 for further details.

Table of Contents

Marketing and Pricing

Ultra derives its revenues principally from the sale of its natural gas and associated condensate production from wells operated by the Company and others in the Green River Basin in southwest Wyoming. The Company s revenues are 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. Energy commodity prices in general, and the Company s regional prices in particular, have been highly volatile in the past, and such high levels of volatility are expected to continue in the future. The Company cannot predict or control the market prices for the sale of its natural gas, condensate, or oil production.

The Company, from time to time, in the regular course of its business, has hedged a portion of its natural gas production primarily through the use of fixed price, forward sales of physical gas, or through the use of financial swaps with creditworthy financial counterparties. The Company may elect to hedge additional portions of its forecast natural gas production in the future, in much the same manner as it has done previously. 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 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.

Natural Gas Marketing

Ultra currently sells all of its natural gas production to a diverse group of third-party, non-affiliated entities in a portfolio of transactions of various durations and prices (daily, monthly and longer term). The Company s customers are 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. As the Rockies Express Pipeline, LLC (REX) becomes operational (as discussed below), the Company s customer base is expected to expand to include customers in the mid-western and eastern United States. The sale of the Company s natural gas is as produced . As such, the Company does not maintain any significant inventories or imbalances of natural gas. The Company maintains credit policies intended to mitigate the risk of uncollectible accounts receivable. The Company does not have any outstanding, uncollectible accounts for its natural gas sales at December 31, 2007.

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 field in southwest Wyoming. Under these agreements, the midstream service providers will expand their facility s capacities in southwest Wyoming to accommodate growing volumes from wells in which the Company owns an interest. These agreements generally contain multi-year commitments for midstream services. The Company has, in recent years, been able to lower some of the gathering and processing fees for such midstream services with its midstream service providers, in exchange for committing to these longer term arrangements. As a result of such negotiations (in both 2005 and 2006), two new, large cryogenic gas processing plants have been constructed in southwest Wyoming. These facilities remove natural gas liquids from the Company s gas (and gas of others) making it sufficient quality to be accepted into the natural gas transmission pipelines serving the area. One of these facilities was placed into service in the first quarter of 2007, and the other, larger, facility is nearing completion and is projected to be completed and fully operational during the first quarter of 2008. The new facilities are expected to add incremental cryogenic processing capacity of approximately 1.1 Bcf per day to the southwest Wyoming area. The Company has contractually secured capacity at both of these facilities for the processing of its natural gas. Ultra believes that the capacity of the midstream infrastructure related to the Company s production will continue to be adequate to allow it to sell essentially all of its available production.

Because local natural gas production typically exceeds local demand for natural gas during non-winter months, the Rocky Mountain Region is usually a net-exporter of natural gas. 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 . The Company has seen significant basis differentials for its Wyoming production versus the Henry Hub (Henry Hub) pricing reference point in south Louisiana in the past. This trend continued and actually became more pronounced in 2007. As a result, the Company realized prices that were significantly lower than those received by companies with natural gas production in other regions of the U.S.

During portions of the second and third quarters of 2007, the Company realized natural gas prices that were lower than those seen in previous years in the southwest Wyoming region. The market price for natural gas in the Rockies generally, and in southwest Wyoming specifically, is influenced by a number of regional and national factors, all of which are unpredictable and are beyond the Company s ability to control or to predict. These factors include, among others, weather, natural gas supplies, natural gas demand, and natural gas pipeline capacity to export gas from the Rockies. Continued robust growth in natural gas production from natural gas fields in Wyoming, Colorado and Utah during 2007, coupled with a nearly 100% utilization of existing natural gas pipeline export capacity, caused natural gas prices in the Rocky Mountain Region to decrease dramatically during the second and third quarters of 2007. In addition, a fire and resulting damage at a compressor station on the Colorado Interstate Gas Company pipeline near Cheyenne, Wyoming during the third quarter of 2007 reduced the export capacity of the natural gas pipeline grid in Wyoming, and the impact to the supply/demand balance (and as a result, spot natural gas prices) was immediate and severe. In response to this dramatic change in the supply/demand balance, the Company made voluntary reductions to its gas sales and physically shut-in some volumes during the third quarter of 2007. With the onset of colder weather, and in response to voluntary producer shut-ins of natural gas production by the Company and others, the widening basis differentials for Rockies production became much less pronounced during the last two months of 2007. For example, the differential between prevailing Wyoming prices and the benchmark Henry Hub price ranged from more than $5 per MMBtu discount in October 2007 to a more narrow discount of approximately $1.20 per MMBtu in December 2007.

In the years past, increases in pipeline capacity to transport production from Rocky Mountain production areas to markets in the west have served to improve (i.e. lower) basis differentials for Wyoming natural gas production. (Examples include: Kern River Pipeline in service May 2003; the Cheyenne Plains Pipeline in service February 2005; and Rockies Express Pipeline expansion to Cheyenne, Wyoming placed into service on February 14, 2007). These expansions of pipeline export capacity have historically reduced but not entirely eliminated the basis differential for natural gas prices in southwest Wyoming when compared to prices at the Henry Hub pricing reference point.

The Company continued to take action toward assuring that the pipeline infrastructure to move its natural gas supplies away from southwest Wyoming would be expanded to provide sufficient capacity to transport its natural gas production and to provide for reasonable basis differentials for its natural gas in the future. The Company agreed to become an anchor shipper on REX, sponsored by subsidiaries of Kinder Morgan, Conoco Phillips, and Sempra Energy. The Rockies Express Pipeline begins at the Opal Processing Plant in southwest Wyoming and traverses Wyoming and several other states to an ultimate terminus in eastern Ohio. This pipeline is ultimately projected to cover more than 1,800 miles and is designed as a large-diameter (42), high-pressure natural gas pipeline. The Rockies Express Pipeline is an interstate pipeline and is subject to the jurisdiction of the United States Federal Energy Regulatory Commission (FERC).

On December 19, 2005, the Company entered into two Precedent Agreements (Precedent Agreements) with REX and Entrega Gas Pipeline, LLC. The Precedent Agreements govern the parties through the design, regulatory process and construction of the pipeline facilities and, subject to certain conditions precedent, the Company will take firm transportation service, when the pipeline facilities are constructed. Commencing upon completion of the pipeline facilities, the Company s commitment involves a capacity of 200,000 MMBtu per day of natural gas for a term of 10 years, and the Company will be obligated to pay REX certain demand charges related to its rights to hold this firm transportation capacity as an anchor shipper. Based on current assumptions, current projections regarding the cost of the expansion and the participation of other shippers in the expansion, the Company currently projects that annual demand charges due may be approximately $70.0 million per year for the term of the contract, exclusive of fuel and surcharges. The Company s Board of Directors approved the Precedent Agreements on February 6, 2006 and Kinder Morgan, as the managing member of REX, advised the Company of their final approval of the Precedent Agreements, and their intent to proceed with the construction of the Rockies Express Pipeline on February 28, 2006.

The pipeline facilities are currently under construction and are anticipated to be completed in stages between 2008 and 2009. REX filed its application for a Certificate of Public Convenience and Necessity for the Rockies

Express West Project (REX-West) with the FERC on May 31, 2006. The REX-West portion of the project is 713 miles of pipeline commencing at Cheyenne Hub (Weld County, CO) and ending in Audrain County, Missouri. The FERC issued a Certificate of Public Convenience and Necessity for REX- West on April 19, 2007 and issued several Notices to Proceed for construction of REX-West in May and June of 2007. Construction on much of the REX-West segment has been completed and interim service commenced on portions of REX-West on January 12, 2008, (from Cheyenne and Opal, Wyoming, as far east as the REX interconnection with ANR pipeline in Brown County, KS.) Interim service provides for the delivery of gas from Opal, Wyoming and other sources to points of interconnection with three significant downstream pipelines on the REX-West segment (NGPL, ANR, and Northern Natural Gas pipelines). This initiation of interim service for the REX-West segment is within two weeks of the projected in-service date estimate provided by Kinder Morgan to the Company when it entered into the aforementioned Precedent Agreements in December 2005, and is a strong indication of the success with which Kinder Morgan has executed its plans for the REX pipeline project to date. The Company has been advised by Kinder Morgan that it expects that the remainder of the REX-West pipeline segment will be completed in March 2008 and that deliveries of REX-West gas into the Panhandle Eastern Pipeline system at Audrain County, Missouri will commence at that time.

The Rockies Express East project (REX-East) segment is planned to commence at the East terminus of the REX-West segment (at the above mentioned interconnection with Panhandle Eastern Pipeline in Audrain County, Missouri), and traverse eastward across Missouri, Illinois, Indiana, and Ohio to its eastern terminus near Clarington, Ohio. The REX partners have filed an application for a Certificate of Public Convenience and Necessity for the REX-East segment (Missouri to Ohio) and have, in response, received a Draft Environmental Impact Statement (EIS) from the FERC, which was issued in November 2007. Following a public comment period on this draft EIS, the FERC has indicated that it expects to issue a Final Certificate of Public Convenience and Necessity during the spring of 2008. Kinder Morgan and the REX partners have indicated that they expect that, assuming the above mentioned FERC REX-East EIS is approved and the Final Certificate is issued as indicated, REX-East construction would commence in late spring 2008. Construction is estimated to be completed on or about January 1, 2009, with the entire REX pipeline being placed into service at that time.

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

Oil Marketing

During a portion of 2007, the Company, through its wholly-owned subsidiary, Sino-American, marketed its share of oil production from the 04/36 and 05/36 Blocks in Bohai Bay, China. On October 22, 2007, the Company completed the sale of Sino-American, which owned our Bohai Bay assets in China, in order to focus on our legacy asset in the Pinedale Field in southwest Wyoming. See Note 11 for further details.

The Company markets its Wyoming condensate (which is an oil-like product that is produced coincident to its natural gas production from gas wells located in the Pinedale Anticline and Jonah Fields in Sublette County, Wyoming), to various purchasers. The pricing of the Company s condensate production is based on NYMEX crude futures daily settlement prices, less a negotiated location and transportation discount and is denominated in U.S. dollars per barrel. The Company s condensate production is gathered from its Wyoming well locations by tanker trucks and is then shipped to other locations for injection into crude oil pipelines or other facilities.

Environmental Matters

In 1998, the U.S. Bureau of Land Management (BLM) initiated preparation of an 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. On July 27, 2000, the BLM issued its Record of Decision (ROD) with respect to the final EIS, which allows for 700 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 winter drilling and completion activity and, proposes mitigation guidelines, standard practices for industry activities and best management practices for sensitive areas. The ROD also provides for annual reviews to compare actual environmental impacts to the environmental impacts estimated in the EIS and provides for adjustments to mitigate such impacts, if necessary. The review team comprises operators, local residents and other affected persons. The Company cannot predict if or how these adjustments may affect permitting, development and compliance under the ROD. The BLM s field manager may also impose additional limitations and mitigation measures as are deemed reasonably necessary to mitigate the impact of drilling and production operations in the area.

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

In August 1999, the BLM required an Environmental Assessment (EA) for the potential increased density drilling in the Jonah Field area. An EA is a more limited environmental study than that conducted under an EIS. The EA was required to address the potential environmental impacts of developing the field on a well density of two wells per 80-acre drilling and spacing unit as opposed to the one well per 80-acre drilling and spacing unit as was approved in the initial Jonah field EIS approved in 1998. The new EA was completed in June 2000. With the approval of this EA and the earlier approval by the WOGCC for drilling of two wells per 80-acre drilling and spacing unit, the Company was permitted to drill infill wells at this well density on the 2,160 gross (1,322 net) acres then owned by the Company in the Jonah field. Subsequently, various other operators have received approval for the drilling of increased density wells in pilot areas at well densities ranging from four wells per 80-acre drilling and spacing unit to sixteen wells per drilling and spacing unit. Results of all of these pilot projects were utilized in acquiring approval from the WOGCC in November 2004 to increase the overall density of development for the Jonah Field to eight wells per 80-acre drilling and spacing unit.

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

During the period from 2003 through year end 2007, Ultra and other operators in the Pinedale field have received approval from the WOGCC to drill increased density and pilot project wells in several areas in the Lance Pool across the Pinedale field. At the end of 2007, there were over a dozen different infill density and pilot project orders granted by the WOGCC and currently in place on the Pinedale field. While a very minor portion of the Pinedale field still provides for one well per 40 acres, a succession of WOGGC approvals through year-end 2007 now provide for and range from two wells per 40 acres (20-acre density) up to a 32 well per 160 acre pilot project (5-acre density). The northern portion of the Pinedale field is operated by Questar Exploration and Production Company (Questar) in which the Company is a working interest partner and owns a working interest in the majority of Questar s acreage. Questar s most recent infill density application, approved in July 2007, provided for the drilling of 16 wells per quarter section (10-acre density). With respect to the central portion of the Pinedale field, approval was granted for development on a two wells per 40-acre density in November 2005. Ultra operates the majority of the acreage covered by this approval. Within this two wells per 40-acre density area and in an additional area in the southern portion of the Pinedale field, in July 2007, Ultra and other operators received approval from the WOGCC to provide for the drilling of 16 wells per quarter section (10-acre density). Finally, in December 2007, Ultra received approval within the aforementioned 16 wells per quarter section area to conduct a pilot program on 640 acres to provide for the drilling of 32 wells per quarter section (5-acre density). With these approvals, approximately 2% (640 gross acres) of the productive area of the Pinedale field in which Company owns a working interest has now been approved by the WOGCC for drilling at the equivalent of 5-acre density; an additional 73% (26,888 gross acres) has been approved for drilling at equivalent 10-acre density; an additional 18% (6,687 gross acres) has been approved for drilling at equivalent 20-acre density, with 7% (2,400 gross acres) still under the state wide 40-acre well density rules. Further drilling and testing within the areas approved for increased density continues, the results of which are being evaluated to determine the overall development strategy for the Pinedale field and the ultimate need for future increases in development density.

In April 2004, Questar asked the BLM to modify winter access restrictions to allow operations on three active pads with two drilling rigs per pad during the winter restriction period. This request required an EA to consider the negative impacts of winter activity relative to the extensive mitigation measures proposed by Questar. On November 9, 2004, the BLM issued a Finding of No Significant Impact (FONSI) which enabled Questar to phase in over the next year the proposed year-round drilling program which allowed two drilling rigs on one pad during the winter of 2004-2005. Questar s proposed mitigation measures included construction of a water and condensate gathering system during the summer of 2005. Questar s proposal allows six rigs to operate from three active pads beginning in the winter of 2005-2006 through the winter of 2013-2014 once implementation of the proposed mitigation measures is complete.

In early 2005, Ultra, along with Anschutz and Shell (Proponents), proposed to the BLM a winter access demonstration project for the Mesa area of the Pinedale field. This area is normally subject to the winter big game stipulation, which prohibits drilling and completion activities in the area from November 15th until April 30th. Under the terms of the proposal, the Proponents were able to operate a total of six rigs, two each on three different winter pads. During this winter demonstration project, the Proponents employed innovative technologies and practices for operations to provide a more beneficial alternative to the current wildlife restrictions. Upon successful completion of the winter demonstration project, the Proponents intend to apply the operations principles demonstrated to implement a long-term development plan that will result in substantially less impact to wildlife, habitat, and local communities than what is allowed under the current Pinedale Anticline Project Area (PAPA) ROD while providing assurance of year-round access from the BLM to permit the implementation of a comprehensive development scenario for the Pinedale field. An EA was conducted by the BLM to evaluate the winter demonstration project proposal and associated impacts and the Proponents received approval from the BLM in September 2005, with issuance of a FONSI. The Proponents began activities in the winter demonstration project in November 2005. The FONSI includes several conditions of approval requiring monitoring and mitigation of impacts on wildlife and monitoring and mitigation of rig engine emissions and noise levels associated with project drilling activities.

Subsequent to the BLM ruling allowing implementation of the winter demonstration project, the 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 Environmental Impact Statement (SEIS) for year-round access in the Pinedale field.

The SEIS process will include assessment of alternative considerations and mitigation requirements that should be considered as alternatives, or in addition, to those included in the proposal. The proposed action includes

Table of Contents

commitments to reduce surface disturbance by utilizing fewer overall pads and drilling more directional wells than called for in the PAPA ROD. The operators have agreed also to implement numerous individual mitigation components. These commitments include use of a full-field liquids gathering system and use advanced rig engine emission reduction technology to protect air quality. A mitigation and monitoring fund would be established to address mitigations to minimize impacts from energy development. Ten-year planning and annual meetings with BLM and appropriate state agencies will allow for proper community planning. The draft SEIS was sent out for public comment on December 15, 2006. The closing date for public comment was April 6, 2007. Due to the comments received on the Alternatives in the original draft SEIS, the BLM determined to issue a revised draft SEIS. The revised draft SEIS (RDSEIS) was sent out for public comment on December 27, 2007. The closing date for public comment was February 11, 2008, and the final ROD is anticipated in the summer of 2008.

In September 2002, the Company received the Oil and Gas Wildlife Stewardship award from the Wyoming Game and Fish Department in recognition of its contribution to wildlife management in the Pinedale area. During 2001, the Company received the Agency/Corporation of the Year award from the Wyoming Wildlife Federation and the Regional Administrator s Award for Environmental Achievement from the U.S. Environmental Protection Agency.

Regulation

Oil and Gas Regulation

The availability of a ready market for oil and natural gas production depends upon numerous factors beyond the Company s control. These factors may include, among other things, state and federal regulation of oil and natural gas production and transportation, as well as regulations governing environmental quality and pollution control, state limits on allowable rates of production by a well or proration unit, the amount of oil and natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive natural gas well may be shut-in because of a lack of an available natural gas pipeline in the areas in which the Company may conduct operations. State and federal regulations are generally intended to prevent waste of oil and natural gas, protect rights to produce oil and natural gas between owners in a common reservoir, control the amount of oil and natural gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines and natural gas plants operated by other companies that provide midstream services to the Company are also subject to the jurisdiction of various federal, state and local agencies.

The Company s sales of natural gas are affected by the availability, terms and costs of transportation both in the gathering systems that transport the natural gas from the wellhead to the interstate pipelines and in the interstate pipelines themselves. The rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines are regulated by the FERC under the Natural Gas Act, as well as under Section 311 of the Natural Gas Policy Act. Since 1985, the FERC has implemented regulations intended to increase competition within the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open-access, non-discriminatory basis. On February 25, 2000, the FERC issued a statement of policy and a final rule concerning alternatives to its traditional cost-of-service rate-making methodology to establish the rates interstate pipelines may charge for services. The final rule revises the FERC s pricing policy and current regulatory framework to improve the efficiency of the market and further enhance competition in natural gas markets. The FERC is also considering a number of regulatory initiatives that could affect the terms and costs of interstate transportation of natural gas by interstate pipelines on behalf of natural gas shippers, including policy inquiries about natural gas quality and interchangeability, selective discounting of transportation services by pipelines to shippers, and proposed rules governing pipeline creditworthiness and collateral standards. Because these regulatory initiatives have not been made final, the approach the FERC will take and the potential impact on natural gas suppliers remain unclear.

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

The Mineral Leasing Act of 1920 (Mineral Act) prohibits direct or indirect ownership of any interest in federal onshore oil and gas leases by a foreign citizen of a country that denies similar or like privileges to citizens of the United States. Such restrictions on citizens of a non-reciprocal country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and gas lease. If this restriction is violated, the corporation s lease can be canceled in a proceeding instituted by the United States Attorney General. Although the regulations of the BLM (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. The Company owns interests in numerous federal onshore oil and gas leases. It is possible that holders of the Company s equity interests may be citizens of foreign countries, which could be determined to be citizens of a non-reciprocal country under the Mineral Act.

See Risk Factors for a discussion of the risks involved in our international operations.

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 governing 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 existing federal, state and local laws, rules and regulations governing the release of materials in the environment or otherwise relating to the protection of the environment, 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 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 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), the federal Resource Conservation and Recovery Act (RCRA) and 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 is considering adopting stricter disposal standards for non-hazardous wastes.

Furthermore, certain wastes generated by the Company s oil and natural gas operations that are currently exempt from treatment as Hazardous Wastes may in the future be designated as Hazardous Wastes under the RCRA or other applicable statutes, and therefore be subject to more rigorous and costly operating and disposal requirements.

Superfund. 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 threats to the public health or the environment and to seek to recover from the PRP the costs of such action. Although CERCLA generally exempts petroleum from the definition of Hazardous Substance, in the course of its operations, the Company has generated and will generate wastes that fall within CERCLA s definition of Hazardous Substances. The Company may also be an owner or operator of facilities on which Hazardous Substances have been released. The Company may be responsible under CERCLA for all or part of the costs to clean up facilities at which such substances have been released and for natural resource damages, as a past or present owner or operator or as an arranger. To its knowledge, the Company has not been named a PRP under CERCLA nor have any prior owners or operators of its properties been named as PRP s related to their ownership or operation of such property.

National Environmental Policy Act. As noted, 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 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, and may trigger 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, including but not limited to the restricting or prohibiting of drilling on a company s activities.

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. The OPA assigns liability, which generally is joint and several, without regard to fault, to each liable party for oil removal costs and 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, a 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 enforcement agencies can bring actions for failure to strictly comply with air pollution regulations or permits and generally enforce compliance through administrative, civil or criminal enforcement actions, resulting in fines, injunctive relief and imprisonment.

Clean Water Act. The CWA restricts the discharge of wastes, including produced waters and other oil and natural gas wastes, into waters of the United States, a term broadly defined. Under the Clean Water Act, permits must be obtained for the routine discharge pollutants into waters of the United States. The CWA provides for administrative, civil and criminal penalties for unauthorized discharges, both routine and accidental, of pollutants and of oil and hazardous substances. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or hazardous substances. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters. In addition, the EPA has promulgated regulations

Table of Contents

that may require permits to discharge storm water runoff, including discharges associated with construction activities.

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 imputed 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 oil and natural gas leases that have species, such as raptors that are listed as threatened or endangered and also sage grouse or other sensitive species, that potentially 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 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 a 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.

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, 2007, the Company had 72 full-time employees, including officers.

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

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

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

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

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

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

We compete with numerous other companies in virtually all facets of our business. The 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 that our Company can permit. Our ability to increase reserves in the future will be dependent on our ability to select and acquire suitable prospects for future exploration and development.

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

- our access to the capital necessary to drill wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;
- our ability to retain the personnel necessary to properly evaluate seismic and other information relating to a property; 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;
- the proximity of natural gas production to those natural gas pipelines;
- the effects of inclement weather;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternative fuel sources;
- state and federal regulations of oil and natural gas marketing; and

federal regulation of natural gas sold or transported in interstate commerce.

Because of these factors, we may be unable to market all of our oil and natural gas that we produce. In addition, we may be unable to obtain favorable prices for the oil and natural gas we produce.

We may experience a temporary decline in revenues if we lose one of our significant customers.

A significant customer as used herein is one that individually accounts for 10% or more of our total natural gas or oil sales. In 2007, we had three significant customers for our natural gas production. To the extent these or any other significant customer reduces the volume of its natural gas purchases from us, we could, theoretically, experience a temporary interruption in sales of, or a lower price for, our natural gas. The Company has numerous other customers that would likely compensate for the loss of one or more of our significant customers by increasing their purchases of our natural gas production.

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

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

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

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

A price decrease may more adversely affect the price received for our Wyoming production than production in other U.S. regions.

Natural gas prices in the southwest Wyoming region are critical to our business. The market price for this natural gas differs from the market indices for natural gas in the Gulf Coast region of the United States due potentially to insufficient pipeline capacity and/or low demand during certain months of the year for natural gas in the Rocky Mountain region of the United States. Therefore, a price decrease may more adversely affect the price received for our Wyoming production than production in the other U.S. regions. There have been, and continue to be, from time to time, numerous proposed pipeline projects, including the Rockies Express Pipeline, that have been announced to transport Rockies and Wyoming natural gas production to markets. Although the Company continuously evaluates its options and opportunities to support these project, there can be no assurance that such infrastructures will be built or that if built, they would prevent large basis differentials from occurring in the future. The Company has mitigated its exposure to this risk by securing capacity rights to transport a portion of its natural gas production on the Rockies Express pipeline and delivering it to markets beyond the Rocky Mountain region.

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

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

require that we acquire permits before commencing drilling;

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

Table of Contents

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. 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 sudden and accidental environmental damages. Accordingly, we may be subject to liability or may be required to cease production from properties in the event of environmental damages.

A significant percentage of our United States operations are conducted on federal lands. These operations are subject to a variety of on-site security regulations as well as other permits and authorizations issued by the BLM, the Wyoming Department of Environmental Quality and other federal agencies. A portion of our acreage is affected by winter lease stipulations that prohibit exploration, drilling and completing activities generally from November 15th to April 30th, but allow production activities all year round. To drill wells in Wyoming, we are required to file an Application for Permit to Drill with the WOGCC. Drilling on acreage controlled by the federal government requires the filing of a similar application with the BLM. These permitting requirements may adversely affect our ability to complete our drilling program at the cost and in the time period anticipated. On large-scale projects, lessees may be required to perform an EIS to assess the environmental impact of potential development, which can delay project implementation and/or result in the imposition of environmental restrictions that could have a material impact on cost or scope.

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 amount we may borrow under the credit facility may not exceed a borrowing base determined by the lenders based on their projections of our future production, future production costs and taxes, commodity prices and other factors. We cannot control the assumptions the lenders use to calculate the borrowing base. The lenders may, without our consent, adjust the borrowing base at any time. If our borrowings under the credit facility exceed the borrowing base, the lenders may require that we repay the excess borrowing. If this occurred, we may have to sell assets or seek financing from other sources. We can make no assurances that we would be successful in selling assets or arranging substitute financing. For a description of the bank credit facility and its principal terms and conditions, see Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

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

Our operations are conducted primarily in the Rocky Mountain region of the United States. The weather in this area 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 Rocky Mountain operations are subject to disruption from winter storms and severe cold, which can limit operations involving fluids and impair access to our facilities. A portion of our acreage is affected by winter lease stipulations that prohibit drilling and completing activities from November 15th to April 30th, but allow production activities all year round.

Our focus on exploration projects increases the risks inherent in our oil and gas activities.

We have historically invested a significant portion of our capital budget in drilling exploratory wells in search of unproved oil and gas reserves. We cannot be certain that these exploratory wells will be productive or that we will recover all or any portion of our investments. To increase the chances for exploratory success, we often invest in seismic or other geo-science data to assist us in identifying potential drilling objectives. Additionally, the cost of drilling, completing and testing exploratory wells is often uncertain at the time of our initial investment. Depending on complications encountered while drilling, the final cost of the well may significantly exceed our original estimate. We use the full cost method of accounting for exploration and development activities as defined by the SEC. Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment and are then depleted using the unit of production method based on our proved reserves.

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

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

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

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

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

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

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

This report includes certain descriptions of our future drilling plans with respect to our prospects. A prospect is an area which our geoscientists have identified what they believe, based on available seismic and geological information, to be indications of hydrocarbons. Our prospects are in various stages of review. Whether or not we ultimately drill a prospect depends on the following factors:

receipt of additional seismic data or reprocessing of existing data;

material changes in oil or natural gas prices;

the costs and availability of drilling equipment;

success or failure of wells drilled in similar formations or which would use the same production facilities;

availability and cost of capital;

changes in the estimates of costs to drill or complete wells;

the approval of partners to participate in the drilling of certain wells;

our ability to attract other industry partners to acquire a portion of the working interest to reduce exposure to costs and drilling risks;

decisions of our joint working interest owners; and

regulatory requirements, including those based on the BLM s interpretation of an EIS and the results of the permitting process.

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

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

We follow the full cost method of accounting for our oil and gas properties. A separate cost center is maintained for expenditures applicable to each country in which we conduct exploration and/or production activities. Under such method, the net book value of properties on a country-by-country basis, less related deferred income taxes, may not exceed a calculated ceiling. The ceiling is the estimated after tax future net revenues from proved oil and gas properties, discounted at 10% per year. In calculating discounted future net revenues, oil and natural gas prices in effect at the time of the calculation are held constant, 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.

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. All statements other than statements of historical facts included in this document, including without limitation, statements in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations regarding our financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of the Company s management for future operations, covenant compliance and 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 expre forward-looking statements. The Company can give no assurances that the assumptions upon which such forward-looking statements are based will prove to be correct.

Forward-looking statements include statements regarding:

- our oil and natural gas reserve quantities, and the discounted present value of those reserves;
- the amount and nature of our capital expenditures;
- drilling of wells;
- the timing and amount of future production and operating costs;

business strategies and plans of management; and

prospect development and property acquisitions.

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

general economic conditions;

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 explorations for and production of oil and natural gas;

difficulties encountered during the explorations 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;

compliance with, or the effect of changes in, the extensive governmental regulations regarding the oil and natural gas business;

actions of operators of our oil and natural gas properties; and

weather conditions.

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

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

None.

Item 2. ***Properties.***

Location and Characteristics

The Company owns oil and natural gas leases in Wyoming and Pennsylvania. The leases in Wyoming are primarily federal leases with 10-year lease terms until establishment of production. Production on a lease extends the lease terms until cessation of that production. The Company owns 39 leases totaling approximately 65,345 gross (36,618 net) acres currently held by production (HBP) in Wyoming. The HBP acreage includes all of the Company s leases held within the productive area of the Pinedale and Jonah fields. The leases in Pennsylvania include both those from private individuals, typically with lease terms of five years until establishment of production and leases from the Commonwealth of Pennsylvania, which have lease term of five years until establishment of production. Production on the Pennsylvania leases extends the lease terms until cessation of that production. The Company owns approximately 640 gross (640 net) acres currently held by production or operations in Pennsylvania.

Green River Basin, Wyoming

As of December 31, 2007, the Company owned developed oil and natural gas leases totaling 17,399 gross (7,638 net) acres in the Green River Basin of Sublette County, Wyoming which represents 92% of the Company s total developed net acreage. The Company owns undeveloped oil and natural gas leases totaling 104,253 gross

(55,118 net) acres in the Green River Basin of Sublette County, Wyoming which represents 28% of the Company s total undeveloped net acreage. The Company s acreage in the Green River Basin primarily covers the Pinedale field with several other undeveloped acreage blocks north and west of the Pinedale field as well as acreage in the Jonah field. Holding costs of leases in Wyoming not held by production were approximately $0.1 million for the year ended December 31, 2007. The primary target on the Company s Wyoming acreage is the tight gas sands of the upper Cretaceous Lance Pool formation.

Exploratory Wells. During 2007, the Company participated in the drilling of a total of 79 gross (43.76 net) productive exploratory wells on the Green River Basin properties. At December 31, 2007, there were 36 gross (17.58 net) additional exploratory wells that commenced during the year that were either still drilling or had drilling operations suspended at a depth short of total depth and thus a determination of productive capability could not be made at year end.

Development Wells. During 2007, the Company participated in the drilling of 72 gross (32.35 net) productive development wells on the Green River Basin properties. At year end 2007, there were 25 gross (11.32 net) additional development wells that commenced during 2007 and were either still drilling or had drilling operations suspended at a depth short of total depth. For purposes of this report, development wells are wells identified as proven, undeveloped locations by the Company s independent petroleum engineering firm, Netherland, Sewell & Associates, Inc., at the previous year end reserve evaluation. When drilled, these locations will be counted as development wells.

Pennsylvania

As of December 31, 2007, the Company owned developed oil and gas leases totaling 640 gross (640 net) acres in the Pennsylvania portion of the Appalachian Basin which represents 8% of the Company s total developed net acreage. The Company owns undeveloped oil and gas leases totaling 251,989 gross (139,460 net) acres in this area which represents 72% of the Company s total undeveloped net acreage. Holding costs of leases in Pennsylvania not held by production were approximately $0.4 million for the year ended December 31, 2007.

Exploratory Wells. During the year ended December 31, 2007, the Company participated in the drilling and completion of a total of two gross (1.12 net) wells in the Marshlands prospect area on the Pennsylvania properties. One of these has been completed and placed on production from the Ordovician shale section. The second well has been plugged back after testing the Silurian Tuscarora formation. This well was being completed in the Devonian Marcellus shale formation at year end 2007. During 2006, the Company acquired a 3D seismic survey covering a large prospect area. Processing of this data set has now been completed and locations are being finalized for potential inclusion in the 2008 drilling program.

Table of Contents

Oil and Gas Reserves

The following table sets forth the Company s quantities of domestic proved reserves, for the years ended December 31, 2007, 2006, and 2005 as estimated by independent petroleum engineers Netherland, Sewell & Associates, Inc. The table summarizes the Company s domestic 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, 2007, 2006 and 2005. In accordance with Ultra s three-year planning and budgeting cycle, proved undeveloped reserves included in this table include only economic locations that are forecast to be on production before January 1, 2011. As of December 31, 2007, proved undeveloped reserves represent 61.8% of the Company s total proved reserves.

		December 31,	
	2007	2006	2005
		(In thousands)	
Proved Undeveloped Reserves			
Natural gas (MMcf)	1,758,431	1,415,132	1,264,632
Oil (MBbl)	14,067	11,321	10,117
Proved Developed Reserves			
Natural gas (MMcf)	1,084,224	842,969	635,591
Oil (MBbl)	8,764	6,522	5,087
Total Proved Reserves (MMcfe)	2,979,644	2,365,159	1,991,447
Estimated future net cash flows, before income tax	$ 13,076,921	$ 6,590,206	$ 12,067,267
Standardized measure of discounted future net cash flows, before income taxes(1)	$ 5,841,194	$ 2,690,464	$ 5,311,312
Future income tax	$ 1,971,792	$ 905,384	$ 1,809,228
Standardized measure of discounted future net cash flows, after income tax	$ 3,869,402	$ 1,785,080	$ 3,502,084
Calculated weighted average price at December 31,			
Gas ($/Mcf)	$ 6.13	$ 4.50	$ 8.00
Oil ($/Bbl)	$ 86.91	$ 59.95	$ 60.81

(1) 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-GAAP 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 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.

The following table sets forth the Company s quantities of proved reserves in China, for the years ended December 31, 2007, 2006 and 2005 as estimated by independent petroleum engineers Ryder Scott Company. In accordance with the Company s new field reserve booking policy, proved reserves were booked after production has commenced. The table summarizes the Company s proved reserves in China, the estimated future net revenues from these reserves and the standardized measure of discounted future net cash flows attributable thereto at December 31, 2007, 2006 and 2005.

	December 31,		
	2007	2006	2005
	(In thousands)		
Proved Undeveloped Reserves			
Natural gas (MMcf)			
Oil (MBbl)		1,301	2,577
Proved Developed Reserves			
Natural gas (MMcf)			
Oil (MBbl)		2,686	2,484
Total Proved Reserves (MMcfe)		23,922	30,366
Estimated future net cash flows, before income tax	$	$ 111,994	$ 166,931
Standardized measure of discounted future net cash flows, before income taxes(1)	$	$ 91,984	$ 134,271
Future Income Tax	$	$ 5,511	$ 59,861
Standardized measure of discounted future net cash flows, after income tax	$	$ 86,473	$ 74,410
Calculated weighted average price at December 31, Oil ($/Bbl)	$	$ 46.57	$ 48.74

(1) 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-GAAP 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 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.

Table of Contents

The following table sets forth the Company s quantities of total proved reserves both domestically and in China, for the years-ended December 31, 2007, 2006 and 2005 as estimated by independent petroleum engineers Netherland, Sewell & Associates, Inc. and Ryder Scott Company. The table summarizes the Company s total 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, 2007, 2006 and 2005. In accordance with Ultra s three-year planning and budgeting cycle, proved undeveloped reserves included in this table include only economic locations that are forecast to be on production before January 1, 2011. At December 31, 2007, proved undeveloped reserves represent 61.8% of the Company s total proved reserves.

	December 31, 2007	December 31, 2006 (In thousands)	December 31, 2005
Proved Undeveloped Reserves			
Natural gas (MMcf)	1,758,431	1,415,132	1,264,632
Oil (MBbl)	14,067	12,622	12,694
Proved Developed Reserves			
Natural gas (MMcf)	1,084,224	842,969	635,591
Oil (MBbl)	8,764	9,208	7,571
Total Proved Reserves (MMcfe)	2,979,644	2,389,081	2,021,813
Estimated future net cash flows, before income tax	$ 13,076,921	$ 6,702,200	$ 12,234,198
Standardized measure of discounted future net cash flows, before income taxes(1)	$ 5,841,194	$ 2,782,448	$ 5,445,583
Future income tax	$ 1,971,792	$ 910,895	$ 1,869,089
Standardized measure of discounted future net cash flows, after income tax	$ 3,869,402	$ 1,871,553	$ 3,576,494

(1) 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-GAAP 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 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.

The Company did not file any reports during the year ended December 31, 2007, with any federal authority or agency with respect to oil and natural gas reserves.

Table of Contents

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,		
	2007	**2006**	**2005**
	(In thousands, except per unit data)		
Production			
Natural gas (Mcf)	109,178	78,395	61,722
Oil (Bbl) US	870	594	464
Oil (Bbl) China (See Note 11 on Discontinued Operations)	1,153	1,603	1,556
Total (Mcfe)	121,316	91,580	73,846
Revenues			
Natural gas sales	$ 509,140	$ 470,324	$ 422,091
Oil sales US	57,498	38,335	26,640
Oil sales China (See Note 11 on Discontinued Operations)	64,822	84,008	67,762
Total revenues	$ 631,460	$ 592,667	$ 516,493
Lease Operating Expenses			
Production costs US(a)	$ 23,968	$ 15,068	$ 9,048
Production costs China(a) (See Note 11 on Discontinued Operations)	11,419	8,922	7,352
Severance/production taxes US	63,480	57,899	52,689
Severance/production taxes China (See Note 11 on Discontinued Operations)	8,113	8,398	3,388
Gathering	27,921	19,721	17,125
Total lease operating expenses	$ 134,903	$ 110,008	$ 89,602
Realized Prices			
Natural gas ($/Mcf, including hedges)	$ 4.66	$ 6.00	$ 6.84
Natural gas ($/Mcf, excluding financial hedges)(b)	$ 4.65	$ 6.00	$ 6.99
Oil ($/Bbl) US	$ 66.08	$ 64.52	$ 57.37
Oil ($/Bbl) China (See Note 11 on Discontinued Operations)	$ 56.21	$ 52.40	$ 43.57
Operating Costs per Mcfe Total Consolidated			
Production costs	$ 0.29	$ 0.26	$ 0.22
Severance/production taxes	$ 0.59	$ 0.72	$ 0.76
Gathering	$ 0.23	$ 0.22	$ 0.23
DD&A	$ 1.24	$ 1.02	$ 0.79
Interest	$ 0.15	$ 0.04	$ 0.04
Total operating costs per Mcfe	$ 2.50	$ 2.26	$ 2.04

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

(b)

In addition to our financial hedges and to a larger extent, we sell a portion of our production pursuant to fixed price forward natural gas sales contracts. During 2007, 2006 and 2005, we sold 6.8 MMMBtu (6%), 20.4 MMMBtu (22%) and 22.2 MMMBtu (30%) pursuant to these contracts, respectively. The average price we received for production sold pursuant to term fixed price contracts was $6.20, $5.86 and $5.95 per MMBtu

Table of Contents

in 2007, 2006 and 2005, respectively. The average spot price (as measured by the Inside FERC First of Month Index for Northwest Pipeline Rocky Mountains) was $3.95, $5.66 and $6.96 per MMBtu in 2007, 2006 and 2005, respectively. If we had sold the production we sold under the fixed price contracts at spot market prices during these periods, we may have received more or less than these prices, because the amount of production we sell could have influenced the spot market prices in the areas in which we produce and because we are able to select among several market indices when selling our production.

Productive Wells

As of December 31, 2007, the Company s total gross and net wells were as follows:

Productive Wells*	**Gross Wells**	**Net Wells**
Natural Gas and Condensate	686.0	301.2

* Productive wells are producing wells plus shut-in wells the Company deems capable of production. A gross well is a well in which a working interest is owned. The number of net wells represents the sum of fractional working interests the Company owns in gross wells.

Oil and Gas Acreage

As of December 31, 2007, the Company had total gross and net developed and undeveloped oil and natural gas leasehold acres in the United States as set forth below. The Company s material undeveloped properties are not subject to a material acreage expiry. The developed acreage is stated on the basis of spacing units designated by state regulatory authorities. The acreage and other additional information concerning the Company s oil and natural gas operations are presented in the following tables.

	Developed Acres		**Undeveloped Acres**	
	Gross	**Net**	**Gross**	**Net**
Wyoming	17,399	7,638	104,253	55,118
Pennsylvania	640	640	251,989	139,460
Other	80	14		
All States	18,119	8,292	356,242	194,578

Drilling Activities

For each of the three fiscal years ended December 31, 2007, 2006 and 2005, the number of gross and net wells drilled by the Company was as follows:

Wyoming Green River Basin

	2007		**2006**		**2005**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**

Development Wells						
Productive	72.00	32.35	80.00	38.44	60.00	23.68
Dry	0.00	0.00	0.00	0.00	0.00	0.00
Total	72.00	32.35	80.00	38.44	60.00	23.68

Table of Contents

At year end, there were 25 gross (11.32 net) additional development wells that were either drilling or had drilling operations suspended. This includes wells in both the Pinedale and Jonah fields.

	2007		2006		2005	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory Wells						
Productive	79.0	43.76	44.0	19.79	18.00	8.62
Dry	0.00	0.00	0.00	0.00	0.00	0.00
Total	79.0	43.76	44.0	19.79	18.00	8.62

At year end there were 36 gross (17.58 net) additional exploratory wells that were either drilling or had drilling operations suspended.

Pennsylvania

	2007		2006		2005	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory Wells						
Productive	2.00	1.12	0.00	0.00	1.00	1.00
Dry	0.00	0.00	0.00	0.00	0.00	0.00
Total	2.00	1.12	0.00	0.00	1.00	1.00

At year end there was 1 gross (1.0 net) exploratory well on which completion operations were ongoing.

China Bohai Bay

	2007		2006		2005	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development Wells						
Productive	15.00	1.34	26.00	2.16	17.00	1.52
Dry	0.00	0.00	0.00	0.00	0.00	0.00
Total	15.00	1.34	26.00	2.16	17.00	1.52
Exploratory Wells						
Productive and Successful Appraisal*	0.00	0.00	0.00	0.00	0.00	0.00
Dry	2.00	0.18	1.00	0.23	1.00	0.18
Total	2.00	0.18	1.00	0.23	1.00	0.18

*

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

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

The Company is currently involved in various routine disputes and allegations incidental to its business operations. While it is not possible to determine the ultimate disposition of these matters, the Company believes that the resolution of all such pending or threatened litigation is not likely to have a material adverse effect on the Company s financial position or results of operations.

Item 4. ***Submission of Matters to a Vote of Security Holders.***

No matters were submitted to a vote of the Company s security holders during the fourth quarter of the fiscal year ended December 31, 2007.

Table of Contents

PART II

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

Since August 3, 2007, the Company s common stock has traded on the New York Stock Exchange (NYSE) under the symbol UPL . Prior to such time, the Company s common stock traded on the American Stock Exchange (AMEX) 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.

2007	**High**	**Low**
First Quarter	$ 53.65	$ 44.20
Second Quarter	$ 64.94	$ 52.09
Third Quarter	$ 62.49	$ 52.16
Fourth Quarter	$ 72.32	$ 61.50

2006	**High**	**Low**
First Quarter	$ 70.00	$ 49.65
Second Quarter	$ 68.60	$ 44.40
Third Quarter	$ 61.84	$ 41.80
Fourth Quarter	$ 56.80	$ 44.60

On February 15, 2008, the last reported sales price of the common stock on the NYSE was $75.67 per share. As of February 15, 2008 there were approximately 435 holders of record of the common stock.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*
Among Ultra Petroleum Corp.

* $100 invested on 12/31/02 in stock or index-including reinvestment of dividends. Fiscal year ending December 31.

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.

Table of Contents

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. Pursuant to this authorization, the Company has commenced a program to purchase up to $500.0 million of the Company s outstanding shares through open market transactions or privately negotiated transactions.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet be Purchased Under the Plans or Programs
Oct 1 Oct 31, 2007		$		$ 718 million
Nov 1 Nov 30, 2007	114,179	$ 68.22	114,179	$ 710 million
Dec 1 Dec 31, 2007	68,346	$ 68.63	68,346	$ 706 million

During the year ended December 31, 2007, the Company repurchased 1,431,170 shares of its common stock in open market transactions for an aggregate $78.9 million at a weighted average price of $55.12 per share. Since the program s inception in May 2006, the Company has purchased a total of 5.4 million shares in open market transactions for an aggregate $276.4 million at a weighted average price of $51.19 per share.

In addition to the shares repurchased in open market transactions during the year ended December 31, 2007, the Company also acquired 265,322 shares delivered by employees for $17.4 million to satisfy the exercise price of the employees stock options and tax withholding obligations in connection with the exercise of employee stock options issued pursuant to the Company s employee incentive plans.

In total, during the year ended December 31, 2007, the Company repurchased 1,696,492 shares of its common stock for an aggregate $96.3 million dollars at a weighted average price of $56.76 per share. Since the program s inception in May 2006, the Company has repurchased 5.7 million shares of its common stock for an aggregate $294.5 million at a weighted average price of $51.73 per share.

Table of Contents

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

The selected consolidated financial information presented below for the years ended December 31, 2007, 2006, 2005, 2004, and 2003 is derived from the Consolidated Financial Statements of the Company. The earnings per share information (Basic income per common share and Diluted income per common share) have been updated to reflect the 2 for 1 stock split on May 10, 2005.

	Year Ended December 31,				
	2007	**2006**	**2005**	**2004**	**2003**
	(In thousands, except per share data)				
Statement of Operations Data					
Revenues:					
Natural gas sales	$ 509,140	$ 470,324	$ 422,091	$ 224,208	$ 114,841
Oil sales	57,498	38,335	26,640	14,659	6,740
Interest and other	1,087	1,941	612	91	37
Total revenues	$ 567,725	$ 510,600	$ 449,343	$ 238,958	$ 121,618
Expenses:					
Production expenses and taxes	115,371	92,688	78,862	47,574	25,224
Depreciation, depletion and amortization	135,470	79,675	48,455	27,346	16,216
General and administrative	8,060	13,328	11,405	6,123	5,568
Stock compensation	5,201	1,557	2,859	924	1,018
Interest	17,760	3,909	3,286	3,783	2,851
Total expenses	281,862	191,157	144,867	85,750	50,877
Income before income taxes	285,863	319,443	304,476	153,208	70,741
Income tax provision	105,621	122,741	107,864	53,406	25,254
Net income from continuing operations	180,242	196,702	196,612	$ 99,802	$ 45,487
Income from discontinued operations (including pre-tax gain on sale of $98,066), net of tax provision of $45,482	82,794	34,493	31,688	9,348	(164)
Net income	$ 263,036	$ 231,195	$ 228,300	$ 109,150	$ 45,323
Basic Earnings per Share:					
Income per common share from continuing operations	$ 1.19	$ 1.28	$ 1.28	$ 0.67	$ 0.31
Income per common share from discontinued operations	$ 0.54	$ 0.22	$ 0.21	$ 0.06	$ 0.00
Net income per common share	$ 1.73	$ 1.50	$ 1.49	$ 0.73	$ 0.31
Fully Diluted Earnings per Share:					

Income per common share from continuing operations	$	1.14	$	1.22	$	1.21	$	0.62	$	0.29
Income per common share from discontinued operations	$	0.52	$	0.21	$	0.20	$	0.06	$	0.00
Net income per common share	$	1.66	$	1.43	$	1.41	$	0.68	$	0.29
Statement of Cash Flows Data										
Net cash provided by (used in):										
Operating activities	$	428,748	$	436,151	$	414,140	$	175,343	$	90,051
Investing activities		(508,746)		(454,841)		(306,549)		(165,014)		(103,622)
Financing activities		76,056		(10,704)		(80,344)		4,770		13,988
Balance Sheet Data Cash and cash equivalents	$	10,632	$	14,574	$	43,968	$	16,721	$	1,804
Working capital (deficit)		(71,472)		55,036		44,600		(18,298)		(20,912)
Oil and gas properties		1,574,529		1,006,998		599,901		381,409		226,893
Total assets		1,776,200		1,258,299		742,566		435,076		264,715
Total long-term debt		290,000		165,000				102,000		99,000
Other long-term obligations		26,672		25,262		19,821		9,312		5,120
Deferred income taxes, net		366,024		252,808		148,743		78,129		25,212
Total shareholders equity		853,579		629,005		571,201		267,992		149,453

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

The following discussion of the financial condition and operating results of the Company should be read in conjunction with the consolidated financial statements and related notes of the Company. Except as otherwise indicated all amounts are expressed in U.S. dollars. We have one operating segment, natural gas and oil exploration and development with one geographical segment, the United States.

The Company currently generates the majority of its revenue, earnings and cash flow from the production and sales of natural gas and oil from its property in southwest Wyoming. The price of natural gas in the southwest Wyoming region is a critical factor to the Company s business. The price of natural gas in southwest Wyoming historically has been volatile. The average annual realizations for the period 2003-2007 have ranged from $2.33 to $8.64 per Mcf. This 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 forward sales and derivative contracts for natural gas in southwest Wyoming. The average realization for the Company s natural gas during calendar 2007 was $4.66 per Mcf, basis Opal, Wyoming, including the effect of hedges. For the quarter ended December 31, 2007, the average realization for the Company s natural gas was $4.42 per Mcf, including the effect of hedges.

The Company has grown its natural gas and oil production significantly over the past five years and management believes it has the ability to continue growing production by drilling already identified locations on its leases in Wyoming. The Company delivered 18% production growth on an Mcfe basis during the quarter ended December 31, 2007 as compared to the same quarter in 2006 and 32% production growth for the year-ended December 31, 2007 compared to the same period in 2006. Management expects to deliver additional production growth during 2008 by drilling and bringing into production additional wells in Wyoming.

	2007	**2006**	**2005**	**2004**	**2003**
Production Bcfe	121.3	91.6	73.8	49.5	28.9

The Company currently conducts operations exclusively in the United States. Substantially all of the oil and natural gas activities are conducted jointly with others and, accordingly, amounts presented reflect only the Company s proportionate interest in such activities. Inflation has not had a material impact on the Company s results of operations and is not expected to have a material impact on the Company s results of operations in the future.

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. Generally Accepted Accounting Principles (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, 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. These policies relate to estimates of volumes of oil and natural gas reserves used in calculating depletion, the amount of standardized measure used in computing the ceiling test limitations and the amount of abandonment obligations used in such calculations. Assumptions, judgments and estimates are also required in determining impairments of undeveloped properties and the valuation of deferred tax assets.

Oil and Gas Reserves. The term proved reserves is defined by the SEC in Rule 4-10(a) of Regulation S-X under the Securities Act of 1933. In general, proved reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs at the date of the estimate. Prices include consideration of changes in existing prices provided by contractual arrangements, but not escalated based on future economic conditions.

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

32

Table of Contents

Company s DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves may result from lower prices, evaluation of additional operating history, mechanical problems on our wells and catastrophic events such as explosions, hurricanes and floods. Lower prices also make it uneconomical to drill wells or produce from fields with high operating costs.

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

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

Investments in unproved properties are not depleted pending the determination of the existence of proved reserves. Unproved properties are assessed periodically to ascertain whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, and geographic and geologic data obtained relating to the properties. Where it is not practicable to individually assess the amount of impairment of properties for which costs are not individually significant, such properties are grouped for purposes of assessing impairment. The amount of impairment assessed is added to the costs to be 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 on a country-by-country basis utilizing prices in effect on the last day of the quarter. SEC regulation S-X Rule 4-10 states that if prices in effect at the end of a quarter are the result of a temporary decline and prices improve prior to the issuance of the financial statements, the increased price may be applied in the computation of the ceiling test. The ceiling limits such pooled costs to the aggregate of the after-tax, present value, discounted at 10%, of future net revenues attributable to proved reserves, known as the standardized measure, 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.

The Company did not have any write-downs related to the full cost ceiling limitation in 2007, 2006, or 2005. As of December 31, 2007, the ceiling limitation exceeded the carrying value of the Company s oil and natural gas properties. Estimates of standardized measure at December 31, 2007 were based on realized natural gas prices which averaged $6.13 per Mcf and on realized liquids prices which averaged $86.91 per barrel in the U.S. A reduction in oil and natural gas prices and/or estimated quantities of oil and natural gas reserves would reduce the ceiling limitation and could result in a ceiling test write-down.

Asset Retirement Obligation. The Company s asset retirement obligations (ARO) consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with its oil and natural gas properties. Statement of Financial Accounting Standard No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143) 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

Table of Contents

undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A.

Entitlements Method of Accounting for Oil and Natural Gas Sales. The Company generally sells natural gas, condensate and crude oil 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 collectibility is reasonably assured. The Company accounts for oil and natural gas sales using the entitlements method. Under the entitlements method, revenue is recorded based upon the Company s ownership share of volumes sold, regardless of whether it has taken its ownership share of such volumes. The Company records a receivable or a liability to the extent it receives less or more than its share of the volumes and related revenue.

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

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

To assess the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. As of December 31, 2007, the Company had net deferred tax assets totaling $24.6 million which management considers is more likely than not to be realized.

Commodity Derivative Instruments and Hedging Activities. The Company may, from time to time, enter into commodity derivative contracts and/or fixed-price physical contracts to manage its exposure to oil and natural gas price volatility. The Company has, in the past, primarily utilized fixed price forward sales of physical gas when it hedges some portion of its Wyoming natural gas production. These transactions are generally placed with major financial institutions or with counterparties of high credit quality that present minimal credit risks to the Company. The Company may also secure payments under these types of transactions by requiring the counterparty to provide letter(s) of credit. The Company may also enter into commodity derivative contracts to manage price volatility. To the extent that it does enter into such derivative transactions, the Company expects that the oil and natural gas reference prices of these commodity derivatives contracts will be based upon crude oil and/or natural gas futures contracts which, when adjusted for location basis differentials, will have a high degree of historical correlation with actual prices the Company receives. Under Statement of Financial Accounting Standard No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133), all derivative instruments are recorded on the balance sheet at fair value. Changes in the derivative s fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the gain or loss on the derivative is deferred in Accumulated Other Comprehensive Income (Loss) to the extent the hedge is effective. For qualifying fair value hedges, the gain or loss on the derivative is offset by the related results of the hedged item in the income statement. Gains and losses on hedging instruments included in Accumulated Other Comprehensive Income (Loss) on the balance sheet are reclassified to Oil and Natural Gas Sales Revenue in the period that the related production is delivered. Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at market value in the consolidated balance sheet, and the associated unrealized gains and losses are recorded as current expense or income in the consolidated statement of operations. The Company currently does have several derivative contracts related to the marketing of its natural gas or oil production that are currently in effect.

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. On January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payment (SFAS No. 123R) 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.

The Company adopted SFAS No. 123R using the modified prospective transition method, which requires the application of the accounting standard as of January 1, 2006, the first day of the Company s fiscal year 2006. Share-based compensation expense recognized under SFAS No. 123R for the years ended December 31, 2007 and 2006 was $2.1 million and $1.2 million, respectively, which consisted of stock-based compensation expense related to employee stock options. See Note 6 for additional information.

Recently issued accounting pronouncements. In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, Fair Value Measurements (SFAS No. 157). This Statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. This statement applies under other accounting pronouncements that require or permit fair value measurements. Accordingly, this statement does not require any new fair value measurements. The changes to current practice resulting from the application of this statement relate to the definition of fair value, the methods used to measure fair value, and the expanded disclosures about fair value measurements. SFAS No. 157 is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. The Company does not anticipate that the implementation of SFAS No. 157 will have a material impact on consolidated results of operations, financial position or liquidity.

In June 2006, the FASB issued FIN 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109, Accounting for Income Taxes. FIN 48 requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority.

Results of Operations Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Oil and natural gas revenues from continuing operations increased 11% to $566.6 million for the year ended December 31, 2007 from $508.7 million for the same period in 2006. This increase was attributable to an increase in the Company s production volumes offset in part by lower prices received. During 2007, the Company s production from continuing operations increased to 109.2 Bcf of natural gas and 870.1 thousand barrels of condensate up from 2006 levels of 78.4 Bcf of natural gas and 594.1 thousand barrels of condensate. This 40% increase on an Mcfe basis was attributable to the Company s successful drilling activities during 2007 and 2006 in Wyoming. During the year ended December 31, 2007, the average product prices received were $4.66 per Mcf including the effects of hedging and $66.08 per barrel of condensate compared to $6.00 per Mcf including the effects of hedging and $64.52 per barrel of condensate for the same period in 2006.

Lease operating expense (LOE) increased to $24.0 million for the year ended December 31, 2007 compared to $15.1 million during the same period in 2006 due to increased production volumes as well as increased water disposal costs in Wyoming. On a unit of production basis, LOE costs increased to $0.21 per Mcfe during the year ended December 31, 2007 as compared to $0.18 per Mcfe during the same period in 2006 due to increased water disposal costs in Wyoming. During the year ended December 31, 2007 production taxes were $63.5 million compared to $57.9 million during the same period in 2006, or $0.55 per Mcfe during the year ended December 31,

Table of Contents

2007 as compared to $0.71 per Mcfe during the same period in 2006. Production taxes are calculated based on a percentage of revenue from production. Therefore, lower prices received decreased production taxes on a per unit basis. Gathering fees increased to $27.9 million during 2007 compared to $19.7 million during 2006 largely due to increased production volumes. On a per unit basis, gathering fees remained flat at $0.24 per Mcfe for the years ended December 31, 2007 and 2006.

DD&A expenses increased to $135.5 million during the year ended December 31, 2007 from $79.7 million for the same period in 2006, attributable to increased production volumes and a higher depletion rate, due to higher development costs. On a unit basis, DD&A increased to $1.18 per Mcfe for the year ended December 31, 2007 from $0.97 per Mcfe for the same period in 2006.

General and administrative expenses decreased by 11% to $13.3 million during the year ended December 31, 2007 compared to $14.9 million for the same period in 2006. On a per unit basis, general and administrative expenses decreased to $0.12 per Mcfe during the year ended December 31, 2007 compared with $0.18 per Mcfe for the same period in 2006. This decrease was primarily attributable to a reduction in year over year compensation expense in combination with higher production volumes.

Interest expense increased to $17.8 million during the year ended December 31, 2007 from $3.9 million during the same period in 2006. The increase is related to increased borrowings under the Company s senior bank facility during 2007.

Net income before income taxes decreased by 11% to $285.9 million for the year ended December 31, 2007 from $319.4 million for the same period in 2006 largely as a result of reduced realized natural gas prices offset in part by increased production volumes.

The income tax provision decreased 14% to $105.6 million for the year ended December 31, 2007 as compared to $122.7 million for the year ended December 31, 2006 attributable to decreased pre-tax income and lower withholding taxes related to share repurchases (See Note 8).

Discontinued operations, net of tax, (which is comprised entirely of results associated with the Chinese operations) increased to $82.8 million for the year ended December 31, 2007 from $34.5 million for the same period in 2006. The increase is primarily related to the closing of the sale of Sino-American Energy Corporation for net proceeds of $208.0 million, which resulted in a pre-tax gain on sale of properties of $98.1 million during the quarter ended December 31, 2007. (See Note 11).

For the year ended December 31, 2007, net income increased by 14% to $263.0 million or $1.66 per diluted share as compared with $231.2 million or $1.43 per diluted share for the same period in 2006.

Results of Operations Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Oil and natural gas revenues from continuing operations increased 13% to $508.7 million for the year ended December 31, 2006 from $448.7 million for the same period in 2005. This increase was attributable to an increase in the Company s production volumes partially offset by lower prices received. During 2006, the Company s production increased to 78.4 Bcf of natural gas and 594.1 thousand barrels of condensate in Wyoming, up from 2005 levels of 61.7 Bcf of natural gas and 464.3 thousand barrels of condensate. This 27% increase on an Mcfe basis was attributable to the Company s successful drilling activities during 2006 and 2005 in Wyoming. During the year ended December 31, 2006, the average product prices received were $6.00 per Mcf including the effects of hedging and $64.52 per barrel of condensate in Wyoming, compared to $6.84 per Mcf and $57.37 per barrel of condensate in Wyoming for the same period in 2005.

LOE increased to $15.1 million in 2006 from $9.0 million in 2005 due to higher production volumes along with increased water disposal costs. On a unit of production basis, LOE costs increased to $0.18 per Mcfe for the year-ended December 31, 2006 as compared to $0.14 per Mcfe during the same period in 2005. Production taxes during the year ended December 31, 2006 were $57.9 million compared to $52.7 million in 2005, or $0.71 per Mcfe in 2006, compared to $0.82 per Mcfe in 2005. Production taxes in Wyoming are calculated based on a percentage of revenue from production. Therefore, lower prices received decreased production taxes on a per unit basis. Gathering fees for the year ended December 31, 2006 increased to $19.7 million in 2006 from $17.1 million in 2005 largely as a result of increased production volumes partially offset by revised gathering and processing agreements. The per unit gathering fees decreased to $0.24 per Mcfe in 2006 as compared to $0.27 per Mcfe in 2005 as a result of increased production volumes during 2006 as well as reduced fees as a result of revised gathering and processing agreements during 2006.

DD&A expenses increased to $79.7 million during the year ended December 31, 2006 from $48.5 million for the same period in 2005. This increase was attributable to increased production volumes and a higher depletion rate due to forecasted increased future development costs. On a unit basis, DD&A expense increased to $0.97 per Mcfe in 2006 from $0.75 per Mcfe in 2005.

General and administrative expenses increased slightly to $14.9 million during the twelve months ended December 31, 2006 as compared to $14.3 million during the same period in 2005. On a per unit basis, general and administrative expenses decreased to $0.18 per Mcfe during the year ended December 31, 2006 as compared to $0.22 per Mcfe for the same period in 2005.

Interest expense increased to $3.9 million in 2006 from $3.3 million in 2005. This increase was largely attributable to the increase in borrowings under the Company s senior bank facility during 2006.

The income tax provision increased to $122.7 million in 2006 from $107.9 million in 2005. This increase was primarily attributable to increased earnings as well as the withholding tax paid in association with our share repurchase program (see Note 8). The Company recognized $27.6 million in current tax expense during 2006. The Company incurred a liability for current payment of income taxes of $3.6 million for the period ending December 31, 2005. During the year-ended December 31, 2006, the Company incurred $10.4 million in withholding tax attributable to the Company s share repurchase program. In conjunction with the share repurchase program, a stock distribution to Ultra Petroleum from Ultra Resources is treated as a dividend for U.S. tax purposes to the extent of earnings and profits of UP Energy and Ultra Resources. U.S. tax rules, including rules under the U.S.-Canada Income Tax Treaty, require a 5% withholding tax when a U.S. corporation distributes a dividend to its sole corporate Canadian shareholder.

Discontinued operations, net of tax, (which is comprised entirely of results associated with the Chinese operations) increased to $34.5 million for the year ended December 31, 2006 from $31.7 million for the same period in 2005. The increase is primarily related increased realized oil prices partially offset by decreased oil production and increased severance taxes, DD&A and income taxes. (See Note 11).

Liquidity and Capital Resources

During the year-ended December 31, 2007, the Company relied on cash provided by operations, borrowings under its senior credit facility and proceeds from the sale of its Chinese operations to finance its capital expenditures. The Company participated in the drilling of 212 wells in Wyoming. For the year ended December 31, 2007 net capital expenditures were $712.3 million ($697.8 million from continuing operations and $14.5 million from discontinued operations). At December 31, 2007, the Company reported a cash position of $10.6 million compared to $14.6 million at December 31, 2006. Working capital at December 31, 2007 was ($71.5) million as compared to $55.0 million at December 31, 2006. As of December 31, 2007, the Company had $290.0 million in outstanding bank indebtedness and other long-term obligations of $26.7 million comprised of items payable in more than one year, primarily related to production taxes.

The Company s positive cash provided by operating activities, along with availability under its senior credit facility, are projected to be sufficient to fund the Company s budgeted capital expenditures for 2008, which are currently projected to be $755.0 million. Of the $755.0 million budget, the Company plans to allocate approximately 95% to

Wyoming and 5% to Pennsylvania. With the budget allocated for Wyoming, the Company plans to drill or participate in an estimated 240 gross wells in 2008. The Company currently has no budget for acquisitions in 2008.

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

Table of Contents

the Company. In the event the existing banks increase their commitment to an amount less than the requested commitment amount, then it would be necessary to add new financial institutions to the credit facility. At December 31, 2007, the Company had $290.0 million outstanding and $210.0 million unused and available under the current committed amount.

Loans under the credit facility are unsecured and bear interest, at our option, based on (A) a rate per annum equal to the higher of the prime rate or the weighted average fed funds rate on overnight transactions during the preceding business day plus 50 basis points, or (B) a base Eurodollar rate, substantially equal to the LIBOR rate, plus a margin based on a grid of our consolidated leverage ratio (87.5 basis points per annum as of December 31, 2007).

The facility has restrictive covenants that include the maintenance of a ratio of consolidated funded debt to EBITDAX (earnings before interest, taxes, DD&A and exploration expense) not to exceed 31/2 times; and until such time as we have obtained an investment grade public debt rating, the maintenance of an annual ratio of the net present value of our oil and gas properties to total funded debt of at least 1.75 to 1.00. At December 31, 2007, we were in compliance with all of our debt covenants. The Company s total commitment fees were $0.4 million, $0.4 million and $0.4 million for the years ended December 31, 2007, 2006 and 2005, respectively.

During the year ended December 31, 2007, net cash provided by operating activities was $428.7 million, a 2% decrease from the $436.2 million for the same period in 2006. The decrease in net cash provided by operating activities was largely attributable 22% lower realized natural gas prices during the year ended December 31, 2007 as compared to the same period in 2006 partially offset by the 32% increase in production during the year ended December 31, 2007.

During the year ended December 31, 2007, net cash used in investing activities was $508.7 million as compared to $454.8 million for the same period in 2006. The increase in net cash used in investing activities is largely due to increased capital expenditures associated with the Company s drilling activities in 2007.

During the year ended December 31, 2007, net cash provided by financing activities was $76.1 million as compared to net cash used in financing activities of $10.7 million for the same period in 2006. The increase in net cash provided by financing activities is primarily attributable to a reduction in the amount of funds used in the Company s share repurchase program during 2007 (See Note 8).

Off-Balance Sheet Arrangements

The Company did not have any off-balance sheet arrangements as of December 31, 2007.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2007:

		Payments Due by Period:			
	Total	Less Than One Year	1-3 Years	3-5 Years	More Than 5 Years
		(Amounts in thousands of U.S. dollars)			
Long-term debt	$ 290,000	$	$	$ 290,000	$
Drilling contracts	127,681	71,221	52,582	3,878	

Operating leases	1,200	1,200			
Office space lease	2,813	645	2,077	91	
Total contractual obligations	$ 421,694	$ 73,066	$ 54,659	$ 293,969	$

As of December 31, 2007, the Company had committed to drilling obligations with certain rig contractors that will continue into 2012. The drilling rigs were contracted to fulfill the 2007-2012 drilling program initiatives in Wyoming.

In May 2007, the Company amended its office leases in Englewood, Colorado and Houston, Texas, both of which it has committed through 2012. The Company s total remaining commitment for office leases is $2.8 million at December 31, 2007 ($0.6 million in 2008, $0.7 million in 2009, 2010 and 2011, and less than $0.1 million in 2012).

On December 19, 2005, the Company signed two Precedent Agreements (Precedent Agreements) with Rockies Express Pipeline, LLC (REX) and Entrega Gas Pipeline, LLC governing how the parties will proceed through the design, regulatory process and construction of the pipeline facilities and, subject to certain conditions precedent, the Company will take firm transportation service if and when the pipeline facilities are constructed. Commencing upon completion of the pipeline facilities, the Company s commitment involves capacity of 200,000 MMBtu per day of natural gas for a term of 10 years, and the Company will be obligated to pay to REX certain demand charges related to its rights to hold this firm transportation capacity as an anchor shipper. Based on current assumptions, current projections regarding the cost of the expansion and the participation of other shippers in the expansion (noting specifically that these assumptions are likely to change materially), the Company currently projects that annual demand charges due may be approximately $70.0 million per year for the term of the contract, exclusive of fuel and surcharges. The Company s Board of Directors approved the Precedent Agreements on February 6, 2006 and Kinder Morgan, as the managing member of REX advised the Company of their final approval of the Precedent Agreements, and their intent to proceed with the construction of the Rockies Express Pipeline on February 28, 2006.

The pipeline facilities are currently under construction and are anticipated to be completed in stages between 2008 and 2009. REX filed its application for a Certificate of Public Convenience and Necessity for the Rockies Express West Project (REX-West) with the FERC on May 31, 2006. The REX-West portion of the project is 713 miles of pipeline commencing at Cheyenne Hub (Weld County, CO) and ending in Audrain County, Missouri. The FERC issued a Certificate of Public Convenience and Necessity for REX- West on April 19, 2007 and issued several Notices to Proceed for construction of REX-West in May and June of 2007. Construction on much of the REX-West segment has been completed and Interim Service commenced on portions of REX-West on January 12, 2008, (from Cheyenne and Opal, Wyoming, as far east as the REX interconnection with ANR pipeline in Brown County, KS.) Interim service provides for the delivery of gas from Opal, Wyoming and other sources to points of interconnection with three significant downstream pipelines on the REX-West segment (NGPL, ANR, and Northern Natural Gas pipelines). This initiation of interim service for the REX-West segment is within two weeks of the projected in-service date estimate provided by Kinder Morgan to the Company when it entered into the aforementioned Precedent Agreements in December 2005, and is a strong indication of the success with which Kinder Morgan has executed its plans for the REX pipeline project to date. The Company has been advised by Kinder Morgan that it expects that the remainder of the REX-West pipeline segment will be completed in March 2008 and that deliveries of REX-West gas into the Panhandle Eastern Pipeline system at Audrain County, Missouri will commence at that time.

The Rockies Express East project (REX-East) segment is planned to commence at the East terminus of the REX-West segment (at the above mentioned interconnection with Panhandle Eastern Pipeline in Audrain County, Missouri), and traverse eastward across Missouri, Illinois, Indiana, and Ohio to its eastern terminus near Clarington, Ohio. The REX partners have filed an application for a Certificate of Public Convenience and Necessity for the REX-East segment (Missouri to Ohio) and have, in response, received a Draft Environmental Impact Statement from the FERC, which was issued in November 2007. Following a public comment period on this draft EIS, the FERC has indicated that it expects to issue a Final Certificate of Public Convenience and Necessity during the spring of 2008. Kinder Morgan and the REX partners have indicated that they expect that, assuming the above mentioned FERC REX-East EIS is approved and the Final Certificate is issued as indicated, REX-East construction would commence in late spring 2008. Construction is estimated to be completed on or about January 1, 2009, with the entire REX pipeline being placed into service at that time.

Additionally, in maintaining its acreage base that is not held by production, the Company incurs certain expenses, including delay rental costs. From year to year, the Company s acreage base varies, sometimes dramatically, rendering it impossible to forecast with any accuracy what the amount of these delay rental costs will be. In 2007, delay rental costs for all of the Company s leases not held by production were approximately $0.4 million.

39

Table of Contents

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

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. Natural gas price realizations ranged from a monthly low of $3.18 per Mcf to a monthly high of $6.85 per Mcf during 2007. Realized natural gas prices are derived from the financial statements which include the effects of hedging and natural gas balancing.

The Company primarily relies on fixed price forward gas sales to manage its commodity price exposure. These fixed price forward gas sales are considered normal sales. The Company may, from time to time and to a lesser extent, use derivative instruments as one way to manage its exposure to commodity prices. The Company has periodically entered into fixed price to index price swap agreements in order to hedge a portion of its production. The oil and natural gas reference prices of these commodity derivatives contracts are based upon crude oil and natural gas futures as listed on the NYMEX, which have a high degree of historical correlation with actual prices the Company receives. Under SFAS No. 133, all derivative instruments are recorded on the balance sheet at fair value. Changes in the derivative s fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) to the extent the hedge is effective. At December 31, 2007, all hedges were considered effective as the hedging instruments offset the change in the hedged transaction s cash flows for the risk being hedged. For qualifying fair value hedges, the gain or loss on the derivative is offset by related results of the hedged item in the income statement. Gains and losses on hedging instruments included in accumulated other comprehensive income (loss) are reclassified to oil and natural gas sales revenue in the period that the related production is delivered. Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at market value in the consolidated balance sheet, and the associated unrealized gains and losses are recorded as current expense or income in the consolidated statement of operations. The Company currently does not have any derivative contracts in place that do not qualify as cash flow hedges.

During 2007, the Company recognized income, which is included in natural gas sales on the income statement, associated with financially settled swaps to counterparties totaling $1.1 million as its net realization from the hedging activities.

The Company also utilizes fixed price forward physical delivery contracts at southwest Wyoming delivery points to hedge its commodity price exposure. The Company had the following fixed price physical delivery contracts in place on behalf of its interest and those of other parties at December 31, 2007. (In November 2007, the Minerals Management Service commenced a Royalty-in-Kind program which had the effect of increasing the Company s average net interest in physical gas sales from 80% to approximately 91%.)

Remaining Contract Period	Volume-MMBTU/Day	Average Price/MMBTU	
Calendar 2008	100,000	$	6.83
Summer 2008 (April October)	20,000	$	6.88
Calendar 2009	10,000	$	7.51
Summer 2009 (April October)	50,000	$	6.77

At December 31, 2007, 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 (all prices NWPL Rockies basis).

Type	Remaining Contract Period	Volume- MMBTU/ Day	Average Price/ MMBTU	Unrealized Gain (000 s) at 12/31/2007*
Swap	Apr 2008 Oct 2008	60,000	$ 6.82	$ 5,625
Swap	Jan 2009 Dec 2009	30,000	$ 7.35	$ 2,009

* Unrealized gains are not adjusted for income tax effect.

Table of Contents

Subsequent to December 31, 2007 and through February 20, 2008, the Company has entered into the following fixed price physical delivery contracts on behalf of its interest and those of other parties:

Remaining Contract Period	Volume-MMBTU/Day	Average Price/MMBTU
Summer 2009 (April October)	20,000	$ 6.79

Subsequent to December 31, 2007 and through February 20, 2008, 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 (all prices NWPL Rockies basis):

Remaining Contract Period	Remaining Contract Period	Volume-MMBTU/Day	Average Price/MMBTU
Swap	Apr 2008 Oct 2008	60,000	$ 6.70

Table of Contents

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, 2007.

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.

/s/ Michael D. Watford
Michael D. Watford
Chief Executive Officer

February 22, 2008

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, 2007, 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, 2007, 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, 2007 and 2006, and the related consolidated statements of operations and retained earnings, shareholders equity, and cash flow for each of the two years in the period ended December 31, 2007 of Ultra Petroleum Corp. and our report dated February 22, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 22, 2008

Table of Contents

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Ultra Petroleum Corp.:

We have audited the accompanying consolidated statements of operations and retained earnings, shareholders equity, and cash flow of Ultra Petroleum Corp. and subsidiaries for the year ended December 31, 2005. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements 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 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 audit provides a reasonable basis for our opinion. In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the results of operations and the cash flows of Ultra Petroleum Corp. and subsidiaries for the year ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Denver, Colorado
March 30, 2006

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholder of
Ultra Petroleum Corp.

We have audited the accompanying consolidated balance sheets of Ultra Petroleum Corp. as of December 31, 2007 and 2006, and the related consolidated statement of operations and retained earnings, shareholders equity, and cash flow for each of the two years in the period ended December 31, 2007. 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, 2007 and 2006, and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

As discussed in Notes 1 and 6 to the consolidated financial statements, Ultra Petroleum Corp. changed its method of accounting for Share-Based Payments in accordance with Statement of Financial Accounting Standards No. 123 (revised 2004) on January 1, 2006. In addition, as discussed in Note 9 to the consolidated financial statements, in 2007 the Company changed its method of accounting for income taxes.

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, 2007, 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 22, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 22, 2008

Table of Contents

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS

	Year Ended December 31, 2007	2006	2005
	(Amounts in thousands of U.S. Dollars, except per share data)		
REVENUES:			
Natural gas sales	$ 509,140	$ 470,324	$ 422,091
Oil sales	57,498	38,335	26,640
	566,638	508,659	448,731
EXPENSES:			
Production expenses and taxes, excluding depreciation and amortization	115,371	92,688	78,862
Depletion, depreciation and amortization	135,470	79,675	48,455
General and administrative, excluding depreciation and amortization	13,261	14,885	14,264
	264,102	187,248	141,581
OPERATING INCOME	302,536	321,411	307,150
OTHER INCOME (EXPENSE):			
Interest income	1,087	1,941	612
Interest expense	(17,760)	(3,909)	(3,286)
	(16,673)	(1,968)	(2,674)
INCOME BEFORE INCOME TAX PROVISION	285,863	319,443	304,476
Income tax provision	105,621	122,741	107,864
NET INCOME FROM CONTINUING OPERATIONS	180,242	196,702	196,612
Income from discontinued operations (including pre-tax gain on sale of $98,066), net of tax provision of $45,482	82,794	34,493	31,688
NET INCOME	263,036	231,195	228,300
RETAINED EARNINGS, beginning of year	624,784	393,589	165,289
RETAINED EARNINGS, end of year	$ 887,820	$ 624,784	$ 393,589
Basic Earnings per Share:			
Income per common share from continuing operations	$ 1.19	$ 1.28	$ 1.28
Income per common share from discontinued operations	$ 0.54	$ 0.22	$ 0.21
Net income per common share	$ 1.73	$ 1.50	$ 1.49

Fully Diluted Earnings per Share:						
Income per common share from continuing operations	$	1.14	$	1.22	$	1.21
Income per common share from discontinued operations	$	0.52	$	0.21	$	0.20
Net income per common share	$	1.66	$	1.43	$	1.41
Weighted average common shares outstanding basic		151,762		153,879		153,100
Weighted average common shares outstanding diluted		158,616		161,615		161,943

See accompanying notes to consolidated financial statements.

Approved on behalf of the Board:

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

Table of Contents

ULTRA PETROLEUM CORP.

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
	(Amounts in thousands of U.S. dollars, except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 10,632	$ 14,574
Restricted cash	2,590	667
Accounts receivable	135,849	87,805
Derivative assets	5,625	
Inventory	13,333	18,929
Assets related to operations held for sale (see Note 11)		119,285
Prepaid drilling costs and other current assets	424	
Total current assets	168,453	241,260
Oil and gas properties, using the full cost method of accounting		
Proved	1,537,751	978,000
Unproved	36,778	28,998
Property, plant and equipment	4,739	1,775
Deferred tax asset	24,618	8,266
Deferred financing costs, derivative assets and other	3,861	
TOTAL ASSETS	$ 1,776,200	$ 1,258,299
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 140,641	$ 75,458
Current taxes payable	10,839	2,207
Liabilities associated with operations held for sale (see Note 11)		13,162
Other current liabilities		530
Capital cost accrual	88,445	94,867
Total current liabilities	239,925	186,224
Long-term debt	290,000	165,000
Deferred income tax liability	366,024	252,808
Other long-term obligations	26,672	25,262
Shareholders equity:		
Common stock no par value; authorized unlimited; issued and outstanding 152,003,671 and 151,795,633 at December 31, 2007 and 2006, respectively	20,050	5,415
Treasury stock	(59,245)	(1,194)
Retained earnings	887,820	624,784
Accumulated other comprehensive income	4,954	

Total shareholders equity	853,579	629,005
Commitments and contingencies (Note 12)		
TOTAL LIABILITIES AND SHAREHOLDERS EQUITY	$ 1,776,200	$ 1,258,299

See accompanying notes to consolidated financial statements.

Table of Contents

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY

	Shares Issued	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total Shareholders Equity
		(Amounts in Thousands)				
Balances at December 31, 2004	150,235	$ 106,514	$ 165,289	$ (2,617)	$ (1,194)	$ 267,992
Stock options exercised	4,794	20,267				20,267
Employee stock plan grants	47	1,389				1,389
Tax benefit of stock options exercised		50,636				50,636
Comprehensive earnings:						
Net earnings			228,300			228,300
Change in derivative instruments fair value				2,617		2,617
Total comprehensive earnings						230,917
Balances at December 31, 2005	155,076	$ 178,806	$ 393,589	$	$ (1,194)	$ 571,201
Stock options exercised	656	9,203				9,203
Employee stock plan grants	34	2,141				2,141
Shares repurchased and retired	(3,970)	(197,551)				(197,551)
Fair value of employee stock option grants		2,313				2,313
Tax benefit of stock options exercised		10,503				10,503
Comprehensive earnings:						
Net earnings			231,195			231,195
Total comprehensive earnings						231,195
Balances at December 31, 2006	151,796	$ 5,415	$ 624,784	$	$ (1,194)	$ 629,005
Stock options exercised	1,849	11,686				11,686
Employee stock plan grants	56	877				877
Shares repurchased and retired	(364)	(20,837)			1,194	(19,643)
Shares repurchased	(1,068)				(59,245)	(59,245)
Net share settlements	(265)	(18,107)				(18,107)

Fair value of employee stock option grants		4,324				4,324
Tax benefit of stock options exercised		36,692				36,692
Comprehensive earnings:						
Net earnings			263,036			263,036
Change in derivative instruments fair value				4,954		4,954
Total comprehensive earnings						267,990
Balances at December 31, 2007	152,004	$ 20,050	$ 887,820	$ 4,954	$ (59,245)	$ 853,579

See accompanying notes to consolidated financial statements.

Table of Contents

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF CASH FLOW

	Year Ended December 31,		
	2007	2006	2005
	(Amounts in thousands of U.S. Dollars)		
Cash flows from operating activities:			
Net income	$ 263,036	$ 231,195	$ 228,300
Adjustments to reconcile net income to net cash provided by operating activities:			
Income from discontinued operations (including pre-tax gain on sale of $98,066), net of tax provision of $45,482	(82,794)	(34,493)	(31,688)
Depletion, depreciation and amortization	135,470	79,675	48,455
Deferred and current non-cash income taxes	127,802	105,681	57,228
Tax benefit of stock options exercised			50,636
Stock compensation	2,137	1,557	2,859
Excess tax benefit from stock based compensation	(36,692)	(10,503)	
Other	177		
Net changes in non-cash working capital:			
Restricted cash	(1,923)	(453)	(2)
Accounts receivable	(48,044)	(12,149)	(47,895)
Prepaid expenses and other current assets	(273)	128	1,598
Accounts payable and accrued liabilities	64,653	26,495	32,814
Other long-term obligations	(1,840)	2,156	7,931
Taxation payable	8,632	2,207	
Net cash provided by operating activities from continuing operations	430,341	391,496	350,236
Net cash provided by operating activities from discontinued operations	(1,593)	44,655	63,904
Net cash provided by operating activities	428,748	436,151	414,140
Cash flows from investing activities:			
Oil and gas property expenditures	(697,800)	(481,391)	(263,507)
Change in capital costs accrual	(6,422)	47,987	(6,239)
Proceeds on sale of subsidiary, net of transaction costs	208,032		
Inventory	5,596	1,677	(16,054)
Purchase of capital assets	(3,702)	(623)	(1,586)
Investing activities from discontinued operations	(14,450)	(22,491)	(19,163)
Net cash (used in) investing activities	(508,746)	(454,841)	(306,549)
Cash flows from financing activities:			
Borrowings of long-term debt, gross	396,000	165,000	22,000
Payments on long-term debt, gross	(271,000)		(124,000)
Repurchased shares	(96,995)	(197,551)	

Proceeds from issuance of common stock		11,686		9,203		20,267
Excess tax benefit from stock based compensation		36,692		10,503		
Deferred financing costs		(1,204)				
Stock issued for compensation		877		2,141		1,389
Net cash provided by (used in) financing activities		76,056		(10,704)		(80,344)
Net (decrease)/increase in cash and cash equivalents		(3,942)		(29,394)		27,247
Cash and cash equivalents, beginning of year		14,574		43,968		16,721
Cash and cash equivalents, end of year	$	10,632	$	14,574	$	43,968
SUPPLEMENTAL INFORMATION						
Cash paid for:						
Interest	$	16,218	$	1,913	$	3,393
Income taxes	$	21,513	$	21,380	$	327
Non-cash tax benefit of stock options exercised					$	50,636

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years Ended December 31, 2007, 2006 and 2005

DESCRIPTION OF THE BUSINESS

(All dollar 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.

1. SIGNIFICANT ACCOUNTING POLICIES:

(a) *Basis of presentation and principles of consolidation:* The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries UP Energy Corporation, Ultra Resources, Inc. and Sino-American Energy through the date of the sale of the China operations. The Company presents its financial statements in accordance with U.S. Generally Accepted Accounting Principles (GAAP). All inter-company transactions and balances have been eliminated upon consolidation.

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

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

(d) *Capital assets:* Capital assets are recorded at cost and depreciated using the declining-balance method based on a seven-year useful life.

(e) *Oil and natural gas properties:* The Company uses the full cost method of accounting for exploration and development activities as defined by the Securities and Exchange Commission (SEC). 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 proven 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.

Oil and natural gas properties include costs that are excluded from capitalized costs being amortized. These amounts represent investments in unproved properties and major development projects. The Company excludes these costs until proved reserves are found or until it is determined that the costs are impaired. All costs excluded are reviewed, at least quarterly, to determine if impairment has occurred. The amount of any impairment is transferred to the capitalized costs being amortized (the depreciation, depletion and amortization (DD&A) 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 prices in effect on the last day of the quarter. SEC regulation S-X Rule 4-10 states that if prices in

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

effect at the end of a quarter are the result of a temporary decline and prices improve prior to the issuance of the financial statements, the increased price may be applied in the computation of the ceiling test. 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. The effect of implementing SFAS No. 143 had no effect on the ceiling test calculation as the future cash outflows associated with settling asset retirement obligations are excluded from this calculation.

(f) *Inventories:* Materials and supplies inventories are carried at the lower of current market value or cost. Inventory costs include expenditures and other charges directly and indirectly incurred in bringing the inventory to its existing condition and location and 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. Inventories of materials and supplies are valued at cost or less. At December 31, 2007, drilling and completion supplies inventory of $13.3 million primarily includes the cost of pipe and production equipment that will be utilized during the 2008 drilling program.

(g) *Forward natural gas sales transactions:* The Company primarily relies on fixed price physical delivery contracts, which are considered sales in the normal course of business, to manage its commodity price exposure. The Company may, from time to time and to a lesser extent, use derivative instruments as one way to manage its exposure to commodity prices. (See Note 7).

(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 of FAS No. 109.

FIN 48 requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority.

(i) *Earnings per share:* Basic earnings per share is computed by dividing net earnings attributable to common stock 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.

Table of Contents

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table provides a reconciliation of the components of basic and diluted net income per common share for the years ended December 31, 2007, 2006 and 2005: (The earnings per share information (Basic earnings per share and fully diluted earnings per share) have been updated to reflect the 2 for 1 stock split on May 10, 2005).

	Year Ended December 31,		
	2007	**2006**	**2005**
Income from continuing operations	$ 180,242	$ 196,702	$ 196,612
Income from discontinued operations	$ 82,794	$ 34,493	$ 31,688
Net Income	$ 263,036	$ 231,195	$ 228,300
Weighted average common shares outstanding during the period	151,762	153,879	153,100
Effect of dilutive instruments	6,854	7,736	8,843
Weighted average common shares outstanding during the period including the effects of dilutive instruments	158,616	161,615	161,943
Basic Earnings per Share:			
Income per common share from continuing operations	$ 1.19	$ 1.28	$ 1.28
Income per common share from discontinued operations	$ 0.54	$ 0.22	$ 0.21
Net income per common share	$ 1.73	$ 1.50	$ 1.49
Fully Diluted Earnings per Share:			
Income per common share from continuing operations	$ 1.14	$ 1.22	$ 1.21
Income per common share from discontinued operations	$ 0.52	$ 0.21	$ 0.20
Net income per common share	$ 1.66	$ 1.43	$ 1.41
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	674	240	540

(j) *Use of estimates:* Preparation of consolidated financial statements in accordance with accounting principles generally accepted in the United States 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:* On January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payment (SFAS No. 123R) 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.

The Company adopted SFAS No. 123R using the modified prospective transition method, which requires the application of the accounting standard as of January 1, 2006, the first day of the Company s fiscal year 2006. Share-based compensation expense recognized under SFAS No. 123R for the year ended December 31, 2007 and 2006 was $2.1 million and $1.2 million, respectively, which consisted of stock-based compensation expense related to employee stock options. See Note 6 for additional information.

52

Table of Contents

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Prior to adopting of SFAS No. 123R on January 1, 2006, the Company followed Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation (SFAS No. 123) which allowed for the continued measurement of compensation cost for such plans using the intrinsic value based method prescribed by APB Opinion No. 25 provided that pro forma results of operations were disclosed for those options granted. Accordingly, the Company accounted for stock options granted to employees and directors of the Company under the intrinsic value method. Had the Company reported compensation costs as determined by the fair value method of accounting for option grants to employees and directors, net income and net income per common share would approximate the following pro forma amounts: (The earnings per share amounts have been adjusted to reflect the 2 for 1 stock split on May 10, 2005).

For the Year Ended December 31,	2005
Net income:	
As reported	$ 228,300
Deduct: Fair value of stock options issued, net of tax	(13,511)
Pro forma	$ 214,789
Net income per common share:	
Basic earnings per share:	
As reported	$ 1.49
Pro forma	$ 1.40
Fully diluted earnings per share:	
As reported	$ 1.41
Pro forma	$ 1.33

For purposes of pro forma disclosures, the estimated fair value of options is amortized to expense over the options vesting period. The weighted-average fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with the following assumptions:

For the Year Ended December 31,	2005
Expected volatility	34.8 - 44.9%
Expected dividends	0.0%
Expected term (in years)	1.9
Risk free rate	4.18% - 4.41%
Expected forfeiture rate	Actual forfeitures

(l) *Revenue Recognition.* Natural gas revenues are recorded on the entitlement method. Under the entitlement method, revenue is recorded when title passes based on the Company s net interest. The Company records its entitled share of revenues based on estimated production volumes. Subsequently, these estimated volumes are adjusted to reflect actual volumes that are supported by third party pipeline statements or cash receipts. Since there is a ready market for natural gas, the Company sells the majority of its products soon after production at various locations at which time title and risk of loss pass to the buyer. Natural gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total natural gas production. Any amount received in excess of the Company s share is treated as a liability. If the Company receives less than its entitled share, the underproduction is recorded as a receivable. At December 31, 2007 the Company had a net natural gas imbalance asset of $3.1 million and at December 31, 2006, the Company had a net natural gas imbalance asset of $1.7 million.

Table of Contents

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(m) *Accumulated Other Comprehensive Income (Loss):* Other comprehensive income (loss) is a term used to define revenues, expenses, gains and losses that under generally accepted accounting principles are reported as separate components of Shareholders Equity instead of net earnings (loss).

	Year Ended December 31,		
	2007	**2006**	**2005**
Net income	$ 263,036	$ 231,195	$ 228,300
Unrealized gain on derivative instruments	7,633		
Taxes on unrealized gain on derivative instruments	(2,679)		
Other comprehensive income	$ 267,990	$ 231,195	$ 228,300

At December 31, 2007, the Company recorded a current asset of $5.6 million, a non-current asset of $3.1 million and a non-current liability of $1.1 million associated with the derivative instruments included in other comprehensive income.

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

(o) *Impact of recently issued accounting pronouncements:* In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, Fair Value Measurements (SFAS No. 157). This Statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. This Statement applies under other accounting pronouncements that require or permit fair value measurements. Accordingly, this Statement does not require any new fair value measurements. The changes to current practice resulting from the application of this Statement relate to the definition of fair value, the methods used to measure fair value, and the expanded disclosures about fair value measurements. SFAS No. 157 is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. The Company does not anticipate that the implementation of SFAS No. 157 will have a material impact on consolidated results of operations, financial position or liquidity.

In June 2006, the FASB issued FIN 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109, Accounting for Income Taxes. FIN 48 requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority. As a result of the implementation of FIN 48, the Company did not have any unrecognized tax benefits and there was no effect on our financial condition or results of operations.

2. ASSET RETIREMENT OBLIGATIONS:

The Company is required to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development and/or normal use of the assets. As of December 31, 2007, the Company has recorded a liability of $8.3 million to account for future obligations associated with its assets in the United States. As of December 31, 2006, the liability associated with its assets in the United States was $6.1 million. Refer to Note 11 for further information regarding the sale of our Bohai Bay operations.

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31, 2007	December 31, 2006
Asset retirement obligations at beginning of period	$ 6,131	$ 2,846
Accretion expense	493	225
Liabilities incurred	2,674	1,682
Liabilities settled	(66)	
Revisions of estimated liabilities	(934)	1,378
Asset retirement obligations at end of period	8,298	6,131
Less: current asset retirement obligations		
Long-term asset retirement obligations	$ 8,298	$ 6,131

3. OIL AND GAS PROPERTIES:

	December 31, 2007	December 31, 2006
Developed Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	$ 1,868,564	$ 1,174,683
Less accumulated depletion, depreciation and amortization	(330,813)	(196,683)
	1,537,751	978,000
Unproven Properties:		
Acquisition and exploration costs	36,778	28,998
	$ 1,574,529	$ 1,006,998

The Company holds interests in domestic projects in which costs related to these interests of $36.8 million 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.

On a unit basis, DD&A from continuing operations was $1.18 per Mcfe for the year ended December 31, 2007 and $0.97 per Mcfe for the same period in 2006.

	Total	2007	2006	2005	Prior
United States:					
Acquisition costs	$ 36,809	$ 5,423	$ 12,780	$ 1,819	$ 16,787
Exploration costs	10,977	3,348	151	546	6,932
Less transfers to proved	(11,008)	(991)	(1,580)	(1,627)	(6,810)
Total	$ 36,778	$ 7,780	$ 11,351	$ 738	$ 16,909

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. CAPITAL ASSETS:

	December 31, 2007 Cost	December 31, 2007 Accumulated Depreciation	December 31, 2007 Net Book Value	December 31, 2006 Net Book Value
Computer equipment	$ 1,504	$ (996)	$ 508	$ 467
Office equipment	408	(245)	163	68
Field equipment	376	(166)	210	941
Property	2,437		2,437	
Other	3,131	(1,710)	1,421	299
	$ 7,856	$ (3,117)	$ 4,739	$ 1,775

5. LONG-TERM LIABILITIES:

	December 31, 2007	December 31, 2006
Bank indebtedness	$ 290,000	$ 165,000
Other long-term obligations	26,672	25,262
	$ 316,672	$ 190,262

Bank indebtedness: The Company (through its subsidiary) is a party to a revolving credit facility with a syndicate of banks led by JP Morgan Chase Bank, N.A. which matures in April 2012. This agreement provides an initial loan commitment of $500.0 million and may be increased to a maximum aggregate amount of $750.0 million at the request of the Company. Each bank has the right, but not the obligation, to increase the amount of its commitment as requested by the Company. In the event the existing banks increase their commitment to an amount less than the requested commitment amount, then it would be necessary to add new financial institutions to the credit facility. At December 31, 2007, the Company had $290.0 million outstanding and $210.0 million unused and available under the current committed amount.

Loans under the credit facility are unsecured and bear interest, at our option, based on (A) a rate per annum equal to the higher of the prime rate or the weighted average fed funds rate on overnight transactions during the preceding business day plus 50 basis points, or (B) a base Eurodollar rate, substantially equal to the LIBOR rate, plus a margin based on a grid of our consolidated leverage ratio (87.5 basis points per annum as of December 31, 2007).

The facility has restrictive covenants that include the maintenance of a ratio of consolidated funded debt to EBITDAX (earnings before interest, taxes, DD&A and exploration expense) not to exceed 31/2 times; and until such time as we have obtained an investment grade public debt rating, the maintenance of an annual ratio of the net present value of our oil and gas properties to total funded debt of at least 1.75 to 1.00. At December 31, 2007, we were in compliance with all of our debt covenants. The Company s total commitment fees were $0.4 million, $0.4 million and $0.4 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Other long-term obligations: These costs relate to the long-term portion of production taxes payable, our asset retirement obligations mentioned in Note 2 and the long-term portion of the Company s incentive compensation plans.

6. SHARE BASED COMPENSATION:

The Company s Stock Incentive Plans are administered by the Compensation Committee of the Board of Directors (the Plan Administrator). The Plan Administrator may make awards of stock options to employees, directors, officers and consultants of the Company as long as the aggregate number of common shares issuable to

Table of Contents

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

any one person pursuant to incentives does not exceed 5% of the number of common shares outstanding at the time of the award. In addition, no participant may receive during any fiscal year of the Company s awards of incentives an aggregate of more than 500,000 common shares. The Plan Administrator determines the vesting requirements and any vesting restrictions or forfeitures that occur in certain circumstances. Incentives may not have an exercise period longer than 10 years. The exercise price of the stock may not be less than the fair market value of the common shares at the time of award, where fair market value means the average high and low trading price of the common shares on the date of the award.

On April 29, 2005, the shareholders approved the adoption of the 2005 Stock Incentive Plan (the 2005 Stock Incentive Plan). The 2005 Stock Incentive Plan authorizes the Plan Administrator to award incentives from the effective date of the 2005 Stock Incentive Plan. The 2005 Stock Incentive Plan is in addition to the Company s existing stock option plans (the 2000 Option Plan and the 1998 Stock Plan). The 2000 Option Plan and the 1998 Stock Plan remain effective and the Company will make grants under each of the existing plans.

The purpose of the 2005 Stock Incentive 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 directors and providing such participants in the 2005 Stock Incentive Plan 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, thus enabling such participants to share in the long-term growth and success of the Company. To accomplish these goals, the 2005 Stock Incentive 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 2005 Stock Incentive Plan is an important component of the total compensation package offered to employees and directors, reflecting the importance that the Company places on motivating and rewarding superior results with long-term, performance-based incentives.

The purposes of the 2000 Option Plan and the 1998 Stock Plan are: (i) to associate the interests of management of the Company and its subsidiaries and affiliates closely with the stockholders to generate an increased incentive to contribute to the Company s future success and prosperity, thus enhancing the value of the Company for the benefit of its stockholders; (ii) to maintain competitive compensation levels thereby attracting and retaining highly competent and talented directors, employees and consultants; and (iii) to provide an incentive to such management for continuous employment with the Company.

Accounting for share-based compensation

In December 2004, the FASB issued SFAS No. 123R. SFAS No. 123R is a revision of SFAS No. 123 and supersedes APB No. 25. Among other items, SFAS No. 123R eliminates the use of APB No. 25 and the intrinsic value method of accounting, and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments, based on the grant date fair value of those awards, in the financial statements. Pro forma disclosure is no longer an alternative under the new standard. Accordingly, the Company adopted SFAS No. 123R as of January 1, 2006.

SFAS No. 123R provides specific guidance on income tax accounting and clarifies how SFAS No. 109, Accounting for Income Taxes, should be applied to stock-based compensation. Benefits associated with the tax deductions in excess of recognized compensation cost are reported as a financing cash flow, rather than as an operating cash flow as required under SFAS No. 123. These future amounts cannot be estimated because they depend on, among other things, when employees exercise stock options.

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Valuation and Expense Information under SFAS 123R

The following table summarizes share-based compensation expense related to employee stock options under SFAS 123R:

	Year-Ended December 31, 2007	Year-Ended December 31, 2006
Total cost of share-based payment plans	$ 4,324	$ 2,314
Amounts capitalized in fixed assets	$ 2,187	$ 1,157
Amounts charged against income, before income tax benefit	$ 2,137	$ 1,157
Amount of related income tax benefit recognized in income	$ 750	$ 406
Cash flow from operations	$ (36,692)	$ (10,503)
Cash flow from financing activities	$ 36,692	$ 10,503

The fair value of each share option award is estimated on the date of grant using a Black-Scholes pricing model based on assumptions noted in the following table. The Company s employee stock options have various restrictions including vesting provisions and restrictions on transfers and hedging, among others, and are often exercised prior to their contractual maturity. Expected volatilities used in the fair value estimate are based on historical volatility of the Company s stock. The Company uses historical data to estimate share option exercises, expected term and employee departure behavior used in the Black-Scholes pricing model. Groups of employees (executives and non-executives) that have similar historical behavior are considered separately for purposes of determining the expected term used to estimate fair value. The assumptions utilized result from differing pre- and post-vesting behaviors among executive and non-executive groups. The risk-free rate for periods within the contractual term of the share option is based on the U.S. Treasury yield curve in effect at the time of grant.

	2007		2006	
	Non-Executives	Executives	Non-Executives	Executives
Expected volatility	41.3-45.8%	43.5-47.4%	43.7-45.8%	43.5-47.4%
Expected dividends	0%	0%	0%	0%
Expected term (in years)	2.75-5.02	3.58-5.55	2.75-4.71	3.58-5.55
Risk free rate	4.16-5.07%	4.69-4.84%	4.51-5.03%	4.76-4.84%
Expected forfeiture rate	18.0%	18.0%	20.0%	20.0%

Securities Authorized for Issuance Under Equity Compensation Plans

As of December 31, 2007, 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).

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	7,589	$	13.72	10,303
Equity compensation plans not approved by security holders	n/a		n/a	n/a
Total	7,589	$	13.72	10,303

58

Table of Contents

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2007:

	Number of Options	Weighted Average Exercise Price (US$)	
Balance, December 31, 2004	12,704	$	0.25 to $24.31
Granted	1,529	$	23.90 to $58.71
Exercised	(4,794)	$	0.32 to $25.68
Forfeited	(50)	$	25.68 to $25.68
Balance, December 31, 2005	9,389	$	0.25 to $58.71
Granted	380	$	46.05 to $67.73
Exercised	(656)	$	0.46 to $40.00
Forfeited	(30)	$	16.97 to $63.05
Balance, December 31, 2006	9,083	$	0.25 to $67.73
Granted	436	$	45.95 to $65.94
Exercised	(1,849)	$	0.25 to $67.73
Forfeited	(81)	$	47.19 to $63.05
Balance, December 31, 2007	7,589	$	0.25 to $67.73

The following tables summarize information about the stock options outstanding at December 31, 2007:

		Options Outstanding					
Range of Exercise Price		Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price		Aggregate Intrinsic Value	
$0.38	0.46	2,020	1.08	$	0.46	$	143,492
$0.25	0.57	640	2.26	$	0.31	$	45,565
$1.49	2.61	911	3.21	$	1.85	$	63,448
$3.91	4.43	520	4.36	$	4.42	$	34,882
$4.83	7.10	643	5.33	$	4.93	$	42,819

$11.68	24.21	1,021	6.27	$	15.10	$	57,564
$23.90	58.71	1,105	7.49	$	36.05	$	39,157
$46.05	67.73	303	8.47	$	57.99	$	4,091
$45.95	65.94	426	9.28	$	53.94	$	7,491

Table of Contents

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Options Exercisable			
Range of Exercise Price	Number Exercisable	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Aggregate Intrinsic Value
$0.38 0.46	2,020	1.08	$ 0.46	$ 143,492
$0.25 0.57	640	2.26	$ 0.31	$ 45,565
$1.49 2.61	911	3.21	$ 1.85	$ 63,448
$3.91 4.43	520	4.36	$ 4.42	$ 34,882
$4.83 7.10	643	5.33	$ 4.93	$ 42,819
$11.68 24.21	1,021	6.27	$ 15.10	$ 57,564
$23.90 58.71	1,105	7.49	$ 36.05	$ 39,157
$46.05 67.73	118	8.24	$ 62.77	$ 1,029
$45.95 65.94				

The aggregate intrinsic value in the preceding tables represents the total pre-tax intrinsic value, based on the Company s closing stock price of $71.50 on December 31, 2007, 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, 2007 was 7.0 million options.

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

	2007	2006
Share options granted	$ 23.85	$ 23.65
Non-vested share options at beginning of year	$ 23.65	$
Non-vested share options at end of year	$ 23.93	$ 23.65
Options vested during the year	$ 22.79	$
Options forfeited during the year	$ 22.25	$ 21.64

There was no stock-based compensation expense related to employee stock options recognized during the year ended December 31, 2005 as the Company adopted the provisions of SFAS No. 123R under the modified prospective transition method effective January 1, 2006. At December 31, 2005, all options granted as of that date had fully vested.

The fair value of shares that vested during the year ended December 31, 2007 was $2.8 million. The total intrinsic value of share options exercised during the years ended December 31, 2007 and 2006 was $104.5 million and $28.7 million, respectively.

At December 31, 2007, there was $9.4 million of total unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the Stock Incentive Plans. That cost is expected to be recognized over a weighted average period of 2.3 years.

PERFORMANCE SHARE PLANS:

Long-Term Equity-Based Incentives

In 2005, we adopted the Long Term Incentive Plan (LTIP) in order to further align the interests of key employees with shareholders and give key employees the opportunity to share in the long-term performance of the Company by achieving specific corporate financial and operational goals. Participants are recommended by the CEO and approved by the Compensation Committee. Selected officers, managers and other key employees are

Table of Contents

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

eligible to participate in the LTIP which has two components, an LTIP Stock Option Award and an LTIP Common Stock Award.

Under the LTIP, each year the Compensation Committee establishes a percentage of base salary for each participant which is multiplied by the participant s base salary to derive an LTI Value (Long Term Incentive Value). With respect to LTIP Stock Option Awards, options are awarded equal to one half of the LTI Value based on the fair value on the date of grant (using Black-Scholes methodology).

The other half of the LTI Value is the target amount that may be awarded to the participant as an LTIP Common Stock Award at the end of a three-year performance period. The Compensation Committee establishes performance measures at the beginning of each three-year overlapping performance period. Each participant is also assigned threshold and maximum award levels in the event that performance is below or above target levels. Awards are expressed as dollar targets and become payable in common shares at the end of each performance period based on the Company s overall performance during such period. A new three-year period begins each January. Participants must be employed by the Company at the time of payment in order to receive an award.

For the first (January 2005 December 2007), second (January 2006 - December 2008) and third (January 2007 December 2009) performance periods, the Compensation Committee established the following performance measures: return on equity, reserve replacement ratio, and production growth.

Also in 2005, we established a Best in Class program for all employees. The Best in Class program recognizes and financially rewards the collective efforts of all of our employees in achieving sustained industry leading performance and the enhancement of shareholder value. Under the Best in Class program, on January 1, 2005 or the employment date if subsequent to January 1, 2005, all employees received a contingent award of stock units equal to $50,000 worth of our common stock based on the average high and low share price on the date of grant. Employees joining the Company after January 1, 2005 will participate on a pro rata basis based on their length of employment during the performance period. The number of units that will vest and become payable is based on our performance relative to the industry during a three-year performance period beginning January 1, 2005, and ending December 31, 2007, and are set at threshold (50%), target (100%) and maximum (150%) levels. For each vested unit, the participant will receive one share of common stock. The performance measures are all sources finding and development cost and full cycle economics, which will be determinable during the first quarter of 2008.

For the year ended December 31, 2007, the Company recognized $0.9 million, $0.8 million and $1.0 million related to the 2005 LTIP, 2006 LTIP and 2007 LTIP, respectively. Of the totals for the year ended December 31, 2007, $0.6 million, $0.5 million and $0.6 million was recognized in pre-tax compensation expense related to the 2005 LTIP, 2006 LTIP and 2007 LTIP, respectively. For the year ended December 31, 2006, the Company recognized $0.7 million and $0.7 million related to the 2005 LTIP and 2006 LTIP, respectively. Of the totals for the year ended December 31, 2006, $0.4 million and $0.4 million was recognized in pre-tax compensation expense related to the 2005 LTIP and 2006 LTIP, respectively. The amounts recognized during 2007 and 2006 assume that maximum performance objectives are attained. If the Company ultimately attains maximum performance objectives, the associated total compensation cost, estimated at December 31, 2007, for the three year performance periods would be approximately $2.3 million, $2.3 million and $2.9 million (before taxes) related to the 2005 LTIP, 2006 LTIP and 2007 LTIP, respectively.

For the year ended December 31, 2007, the Company recognized $1.7 million associated with the Best in Class Incentive Compensation Program. Of the total for the year ended December 31, 2007, $1.1 million was recognized in pre-tax compensation expense, while the remaining $0.6 million was capitalized in oil and gas properties. For the year ended December 31, 2006, the Company recorded $0.5 million associated with the Best in Class Incentive Compensation Program. Of the total for the year ended December 31, 2006, the Company recognized $0.3 million in pre-tax compensation expense related to the Best in Class program, while the remaining $0.2 million was capitalized in oil and gas properties. The amount recognized to date assumes that maximum performance levels are achieved.

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. DERIVATIVE FINANCIAL INSTRUMENTS:

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. Natural gas price realizations ranged from a monthly low of $3.18 per Mcf to a monthly high of $6.85 per Mcf during 2007. Realized natural gas prices are derived from the financial statements which include the effects of hedging and natural gas balancing.

The Company primarily relies on fixed price forward gas sales to manage its commodity price exposure. These fixed price forward gas sales are considered normal sales. The Company may, from time to time and to a lesser extent, use derivative instruments as one way to manage its exposure to commodity prices. The Company has periodically entered into fixed price to index price swap agreements in order to hedge a portion of its production. The oil and natural gas reference prices of these commodity derivatives contracts are based upon crude oil and natural gas futures as listed on the NYMEX, which have a high degree of historical correlation with actual prices the Company receives. Under SFAS No. 133, all derivative instruments are recorded on the balance sheet at fair value. Changes in the derivative s fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) to the extent the hedge is effective. At December 31, 2007, all hedges were considered effective as the hedging instruments offset the change in the hedged transaction s cash flows for the risk being hedged. For qualifying fair value hedges, the gain or loss on the derivative is offset by related results of the hedged item in the income statement. Gains and losses on hedging instruments included in accumulated other comprehensive income (loss) are reclassified to oil and natural gas sales revenue in the period that the related production is delivered. Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at market value in the consolidated balance sheet, and the associated unrealized gains and losses are recorded as current expense or income in the consolidated statement of operations. The Company currently does not have any derivative contracts in place that do not qualify as cash flow hedges.

During 2007, the Company recognized income, which is included in natural gas sales on the income statement, associated with financially settled swaps to counterparties totaling $1.1 million as its net realization from the hedging activities.

The Company also utilizes fixed price forward physical delivery contracts at southwest Wyoming delivery points to hedge its commodity price exposure. The Company had the following fixed price physical delivery contracts in place on behalf of its interest and those of other parties at December 31, 2007. (In November 2007, the Minerals Management Service commenced a Royalty-in-Kind program which had the effect of increasing the Company s average net interest in physical gas sales from 80% to approximately 91%.)

Remaining Contract Period	**Volume-MMBTU/Day**	**Average Price/MMBTU**
Calendar 2008	100,000	$ 6.83
Summer 2008 (April October)	20,000	$ 6.88

Calendar 2009	10,000	$	7.51
Summer 2009 (April October)	50,000	$	6.77

62

Table of Contents

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At December 31, 2007, 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 (all prices NWPL Rockies basis).

Type	Remaining Contract Period	Volume- MMBTU/ Day	Average Price/ MMBTU	Unrealized Gain (000 s) at 12/31/2007*
Swap	Apr 2008 Oct 2008	60,000	$ 6.82	$ 5,625
Swap	Jan 2009 Dec 2009	30,000	$ 7.35	$ 2,009

* Unrealized gains are not adjusted for income tax effect.

Subsequent to December 31, 2007 and through February 20, 2008, the Company has entered into the following fixed price physical delivery contracts on behalf of its interest and those of other parties:

	Volume- MMBTU/Day	Average Price/MMBTU
Summer 2009 (April October)	20,000	$ 6.79

Subsequent to December 31, 2007 and through February 20, 2008, 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 (all prices NWPL Rockies basis):

Remaining Contract Period	Remaining Contract Period	Volume- MMBTU/Day	Average Price/MMBTU
Swap	Apr 2008 Oct 2008	60,000	$ 6.70

8. SHARE REPURCHASE PROGRAM:

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. Pursuant to this authorization, the Company has commenced a program to purchase up to $500.0 million of the Company s outstanding shares through open market transactions or privately negotiated transactions. The stock repurchase will be funded with cash held in an Ultra Resources bank account or the Company s senior credit facility.

Ultra Petroleum Corp. (Ultra Petroleum) owns 100% of UP Energy Corporation (UP Energy), which in turn owns 100% of Ultra Resources, Inc. (Ultra Resources). Ultra Resources may, from time to time, repurchase Ultra Petroleum publicly traded stock. Subsequent to settlement, the repurchased stock will be transferred to Ultra Petroleum.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet be Purchased Under the Plans or Programs
Oct 1 Oct 31, 2007		$		$ 718 million
Nov 1 Nov 30, 2007	114,179	$ 68.22	114,179	$ 710 million
Dec 1 Dec 31, 2007	68,346	$ 68.63	68,346	$ 706 million

During the year ended December 31, 2007, the Company repurchased 1,431,170 shares of its common stock in open market transactions for an aggregate $78.9 million at a weighted average price of $55.12 per share. Since the program s inception in May 2006, the Company has purchased a total of 5.4 million shares in open market transactions for an aggregate $276.4 million at a weighted average price of $51.19 per share.

Table of Contents

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In addition to the shares repurchased in open market transactions during the year ended December 31, 2007, the Company also acquired 265,322 shares delivered by employees for $17.4 million to satisfy the exercise price of the employees stock options and tax withholding obligations to satisfy tax withholding obligations in connection with the vesting of equity shares of common stock issued pursuant to the Company s employee incentive plans.

In total, during the year ended December 31, 2007, the Company repurchased 1,696,492 shares of its common stock for an aggregate $96.3 million dollars at a weighted average price of $56.76 per share. Since the program s inception in May 2006, the Company has repurchased 5.7 million shares of its common stock for an aggregate $294.5 million at a weighted average price of $51.73 per share.

9. INCOME TAXES:

Income from continuing operations before income taxes is as follows:

	Year Ended December 31,		
	2007	2006	2005
United States	$ 286,045	$ 320,033	$ 304,943
Foreign	(182)	(590)	(467)
Total	$ 285,863	$ 319,443	$ 304,476

The consolidated income tax provision is comprised of the following:

	Year Ended December 31,		
	2007	2006	2005
Current:			
U.S. federal & state	$ 14,511	$ 27,563	$ 50,636
Foreign			
Deferred:			
U.S. federal & state	91,110	95,178	57,228
Foreign			
Total income tax provision	$ 105,621	$ 122,741	$ 107,864

During 2007, 2006 and 2005, the Company realized tax benefits of $36.7 million, $10.5 million and $50.6 million, respectively, attributable to tax deductions associated with the exercise of stock options. These benefits reduce the amount of the Company s U.S. federal and state cash tax payments and are recorded as a reduction of current taxes payable and as an increase in shareholders equity.

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

	Year Ended December 31,		
	2007	2006	2005
Income tax provision computed at the U.S. statutory rate	$ 100,052	$ 111,805	$ 106,567
State income tax provision net of federal benefit	423	150	297
Withholding tax on share repurchase transactions	1,068	10,401	
Other, net	4,078	385	1,000
	$ 105,621	$ 122,741	$ 107,864

During 2007, the Company incurred U.S. withholding taxes totaling $1.1 million in connection with the repurchase of 431,250 shares of its common stock. (See Note 8).

Table of Contents

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended December 31, 2007	2006
Deferred tax assets:		
U.S. federal tax credit carryforwards	$ 20,101	$ 7,101
Canadian net operating loss carryforwards	1,808	1,475
Other, net	4,517	1,165
	26,426	9,741
Valuation allowance Canadian net operating loss carryforwards	(1,808)	(1,475)
Net deferred tax assets Long-term	$ 24,618	$ 8,266
Deferred tax liabilities:		
Property and equipment	(363,345)	(252,808)
Other comprehensive income, tax effect of derivative instruments	(2,679)	
Net deferred tax liabilities Long-term	$ (366,024)	$ (252,808)
Net deferred tax asset (liability) Long-term	$ (341,406)	$ (244,542)

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 FIN 48. The amount of unrecognized tax benefits did not materially change as of December 31, 2007.

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

The Company files a consolidated federal income tax return in the United States Federal jurisdiction and various combined, consolidated, unitary, and separate filings in several state and foreign 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 1997.

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

As of December 31, 2007, the Company had approximately \$19.3 million and \$0.8 million of U.S. federal alternative minimum tax credit and foreign tax carryforwards, respectively (Tax Credits). The Tax Credits are available to offset future U.S. income taxes. None of the Tax Credits expire prior to 2017.

As of December 31, 2004, the Company had U.S. federal regular tax net operating loss carryforwards (NOL s) of approximately \$16.7 million which were available to offset future U.S. taxable income. The Company

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

did not record any valuation allowance attributable to its U.S. NOL s as management estimated that it was more likely than not that the U.S. NOL s would be fully utilized before they expired. These U.S. NOL s were fully utilized to offset U.S. taxable income in 2005.

The Company has Canadian non-capital tax loss carryforwards of approximately $5.2 million and $4.2 million as of December 31, 2007 and December 31, 2006, respectively. The benefit of the Canadian loss carryforwards can only be utilized to the extent the Company generates future taxable income in Canada. If not utilized, the Canadian loss carryforward will expire between 2008 and 2016.

Since the Company currently has no income producing operations in Canada, management estimates that it is more likely than not that the Canadian loss carryforwards will not be utilized. A valuation allowance has been recorded at December 31, 2007 and December 31, 2006 attributable to this deferred tax asset.

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

The Company periodically uses derivative instruments designated as cash flow hedges 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. At December 31, 2007, the Company had open derivative contracts; and, therefore, recorded a deferred tax liability attributable to unrecognized gain on derivative instruments of $2.7 million, which was allocated directly to Other Comprehensive Income. As of December 31, 2006 and December 31, 2005, the Company had no open derivative contracts; and, therefore, no recorded tax benefit attributable to unrecognized loss on derivative instruments.

10. EMPLOYEE BENEFITS:

The Company sponsors a qualified, tax-deferred savings plan in accordance with provisions of Section 401(k) of the Internal Revenue Code for its employees. Employees may defer up to 15% of their compensation, subject to certain limitations. The Company matches the employee contributions up to 5% of employee compensation along with a profit sharing contribution of 8%. The expense associated with the Company s contribution was $0.9 million, $0.7 million and $0.5 million for the years ended December 31, 2007, 2006 and 2005, respectively.

11. DISCONTINUED OPERATIONS:

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

On September 26, 2007, Ultra Petroleum Corp. s wholly-owned subsidiary, UP Energy Corporation, a Nevada corporation, entered into a definitive share purchase agreement with an effective date of June 30, 2007 and a closing date of October 22, 2007 in order to sell all of the outstanding shares of Sino-American Energy Corporation (Sino-American), a Texas corporation, for a total purchase price of US$223.0 million, subject to adjustments. The Company recorded results of operations for the China properties through the close date of October 22, 2007.

Sino-American held all of Ultra Petroleum Corp. s interests in oil and gas production sharing contracts in Bohai Bay, China. The purchaser is SPC E&P (China) Pte. Ltd., a wholly-owned subsidiary of Singapore Petroleum Company. For tax purposes, this transaction was treated as an asset sale as the Company agreed to make a 338(h)(10) election in the stock purchase agreement.

Table of Contents

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	For the Year Ended December 31, 2007	2006	2005
Operating revenues	$ 64,822	$ 84,008	$ 67,762
Gain on sale of subsidiary	98,066		
Lease operating expenses	11,419	8,922	7,352
Severance taxes	8,113	8,398	3,388
Depletion, depreciation and amortization expenses	14,981	13,822	9,648
General and administrative expenses	99	52	78
Income before income tax provision	128,276	52,814	47,296
Income tax provision	45,482	18,321	15,608
Income from discontinued operations, net of tax	$ 82,794	$ 34,493	$ 31,688

The major classes of Assets related to operations held for sale and Liabilities associated with operations held for sale on the Balance Sheet at December 31, 2006 were as follows:

	December 31, 2006
ASSETS	
Current assets:	
Cash and cash equivalents	$ 133
Accounts receivable	2,294
Inventory	408
Prepaid drilling costs and other current assets	4,024
Total current assets	6,859
Oil and gas properties, net, using the full cost method of accounting	112,371
Capital assets	55
Total assets related to operations held for sale	$ 119,285
LIABILITIES AND SHAREHOLDERS EQUITY	
Current liabilities:	

Accounts payable and accrued liabilities	$	833
Current taxes payable		4,635
Total current liabilities		5,468
Other long-term obligations		1,311
Deferred income tax liability		6,383
Total liabilities associated with operations held for sale	$	13,162

12. COMMITMENTS AND CONTINGENCIES:

In May 2007, the Company amended its office leases in Englewood, Colorado and Houston, Texas, both of which it has committed through 2012. The Company s total remaining commitment for office leases is $2.8 million

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

at December 31, 2007 ($0.6 million in 2008, $0.7 million in 2009, 2010 and 2011, and less than $0.1 million in 2012). During the years ended December 31, 2007, 2006 and 2005, the Company recognized expense associated with its office leases in the amount of $0.6 million, $0.4 million, and $0.3 million, respectively.

As of December 31, 2007, the Company had committed to drilling obligations with certain rig contractors totaling $127.7 million ($71.2 million due in 2008, $52.6 million due in one to three years, and the remaining $3.9 million due in three to five years). The commitments expire in 2011 and were entered into to fulfill the Company s 2007-2011 drilling program initiatives in Wyoming.

On December 19, 2005, the Company entered into two Precedent Agreements (Precedent Agreements) with Rockies Express Pipeline, LLC (REX) and Entrega Gas Pipeline, LLC. The Precedent Agreements govern the parties through the design, regulatory process and construction of the pipeline facilities and, subject to certain conditions precedent, the Company will take firm transportation service, if and when the pipeline facilities are constructed. Commencing upon completion of the pipeline facilities, the Company s commitment involves capacity of 200,000 MMBtu per day of natural gas for a term of 10 years, and the Company will be obligated to pay to REX certain demand charges related to its rights to hold this firm transportation capacity as an anchor shipper. Based on current assumptions, current projections regarding the cost of the expansion and the participation of other shippers in the expansion, the Company currently projects that annual demand charges due may be approximately $70.0 million per year for the term of the contract, exclusive of fuel and surcharges. The Company s Board of Directors approved the Precedent Agreements on February 6, 2006 and Kinder Morgan, as the managing member of REX advised the Company of their final approval of the Precedent Agreements, and their intent to proceed with the construction of the Rockies Express Pipeline on February 28, 2006.

The pipeline facilities are currently under construction and are anticipated to be completed in stages between 2008 and 2009. Construction on much of the REX-West segment has been completed and Interim Service commenced on portions of REX-West on January 12, 2008, (from Cheyenne and Opal, Wyoming, as far east as the REX interconnection with ANR pipeline in Brown County, KS). The Company has been advised by Kinder Morgan that it expects that the remainder of the REX-West pipeline segment will be completed in March 2008 and that deliveries of REX-West gas into the Panhandle Eastern Pipeline system at Audrain County, Missouri will commence at that time.

The Rockies Express East project (REX-East) segment is planned to commence at the East terminus of the REX-West segment, and traverse eastward across Missouri, Illinois, Indiana, and Ohio to its eastern terminus near Clarington, Ohio. The REX partners have filed an application for a Certificate of Public Convenience and Necessity for the REX-East segment (Missouri to Ohio) and have, in response, received a Draft Environmental Impact Statement from the FERC, which was issued in November 2007. Following a public comment period on this draft EIS, the FERC has indicated that it expects to issue a Final Certificate of Public Convenience and Necessity during the spring of 2008. Kinder Morgan and the REX partners have indicated that they expect that, assuming the above mentioned FERC REX-East EIS is approved and the Final Certificate is issued as indicated, REX-East construction would commence in late spring 2008. Construction is estimated to be completed on or about January 1, 2009, with the entire REX pipeline being placed into service at that time.

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.

13. FAIR VALUE OF FINANCIAL INSTRUMENTS:

For certain of the Company s financial instruments, including accounts receivable, notes receivable, accounts payable and accrued liabilities, the carrying amounts approximate fair value due to the immediate or short-term

Table of Contents

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

maturity of these financial instruments. The Company s long term debt is comprised of senior bank debt which bears interest at floating rates. Accordingly, the carrying value of the Company s senior bank debt approximated fair value at December 31, 2007.

14. SIGNIFICANT CUSTOMERS:

The Company s revenues are derived principally from uncollateralized sales to customers in the natural gas and oil industry. The concentration of credit risk in a single industry affects the Company s overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions. A significant customer is defined as one that individually accounts for 10% or more of the Company s total natural gas sales during 2007. In 2007, the Company had three significant customers which purchased its natural gas production accounting for $123.3 million (21%), $73.4 million (12%) and $59.0 million (10%) of its natural gas revenues. At December 31, 2007, the Company had outstanding receivables (which were all paid in full in January 2008) from these three significant customers totaling $33.6 million.

15. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED):

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
2007					
Revenues from continuing operations	$ 156,903	$ 131,180	$ 117,418	$ 162,224	$ 567,725
Expenses from continuing operations	$ 64,230	$ 67,481	$ 66,935	$ 83,216	$ 281,862
Income before income tax provision	$ 92,673	$ 63,699	$ 50,483	$ 79,008	$ 285,863
Income tax provision	$ 32,030	$ 23,949	$ 17,727	$ 31,915	$ 105,621
Income from continuing operations	$ 60,643	$ 39,750	$ 32,756	$ 47,093	$ 180,242
Revenues from discontinued operations	$ 19,617	$ 25,951	$ 19,254	$ 98,066	$ 162,888
Expenses from discontinued operations	$ 9,683	$ 12,399	$ 12,110	$ 420	$ 34,612
Income tax provision - discontinued operations	$ 3,985	$ 4,235	$ 2,500	$ 34,762	$ 45,482
Net income	$ 66,592	$ 49,067	$ 37,400	$ 109,977	$ 263,036
Basic Earnings per Share:					
Income per common share from continuing operations	$ 0.40	$ 0.26	$ 0.22	$ 0.31	$ 1.19
	$ 0.04	$ 0.06	$ 0.03	$ 0.42	$ 0.54

Income per common share from discontinued operations										
Net income per common share	$	0.44	$	0.32	$	0.25	$	0.73	$	1.73
Fully Diluted Earnings per Share:										
Income per common share from continuing operations	$	0.38	$	0.25	$	0.21	$	0.30	$	1.14
Income per common share from discontinued operations	$	0.04	$	0.06	$	0.03	$	0.40	$	0.52
Net income per common share	$	0.42	$	0.31	$	0.24	$	0.70	$	1.66

Revenues from discontinued operations for the fourth quarter of 2007 include the gain on sale associated with the China properties in the amount of $98.1 million.

Table of Contents

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
2006					
Revenues from continuing operations	$ 126,389	$ 105,592	$ 127,818	$ 150,801	$ 510,600
Expenses from continuing operations	$ 40,385	$ 38,018	$ 50,122	$ 62,632	$ 191,157
Income before income tax provision	$ 86,004	$ 67,574	$ 77,696	$ 88,169	$ 319,443
Income tax provision	$ 36,492	$ 19,433	$ 35,939	$ 30,877	$ 122,741
Income from continuing operations	$ 49,512	$ 48,141	$ 41,757	$ 57,292	$ 196,702
Revenues from discontinued operations	$ 25,432	$ 25,071	$ 17,833	$ 15,672	$ 84,008
Expenses from discontinued operations	$ 7,470	$ 8,712	$ 6,724	$ 8,288	$ 31,194
Income tax provision - discontinued operations	$	$ 13,825	$ 390	$ 4,106	$ 18,321
Net income	$ 67,474	$ 50,675	$ 52,476	$ 60,570	$ 231,195
Basic Earnings per Share:					
Income per common share from continuing operations	$ 0.32	$ 0.31	$ 0.27	$ 0.38	$ 1.28
Income per common share from discontinued operations	$ 0.11	$ 0.02	$ 0.07	$ 0.02	$ 0.22
Net income per common share	$ 0.43	$ 0.33	$ 0.34	$ 0.40	$ 1.50
Fully Diluted Earnings per Share:					
Income per common share from continuing operations	$ 0.30	$ 0.30	$ 0.26	$ 0.36	$ 1.22
Income per common share from discontinued operations	$ 0.11	$ 0.01	$ 0.07	$ 0.02	$ 0.21
Net income per common share	$ 0.41	$ 0.31	$ 0.33	$ 0.38	$ 1.43

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 Financial Accounting Standards Board Statement No. 69, Disclosure About Oil and Gas Producing Activities:

A. OIL AND GAS RESERVES:

The determination of oil and natural gas reserves is complex and highly interpretive. Assumptions used to estimate reserve information may significantly increase or decrease such reserves in future periods. The estimates of reserves are subject to continuing changes and, therefore, an accurate determination of reserves may not be possible for many years because of the time needed for development, drilling, testing, and studies of reservoirs. The following unaudited tables as of December 31, 2007, 2006 and 2005 are based upon estimates prepared by Netherland, Sewell & Associates, Inc. and estimates provided by Ryder Scott Company as of December 31, 2006 and 2005. The estimates for properties in the United States were prepared by Netherland, Sewell & Associates, Inc. in reports dated February 4, 2008, January 30, 2007 and January 27, 2006, 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, 2007, 2006 and 2005. All such reserves are located in the Green River Basin, Wyoming, and Pennsylvania.

Table of Contents

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

B. ANALYSES OF CHANGES IN PROVEN RESERVES:

	United States		China		Total	
	Oil (Bbls)	Natural Gas (Mcf)	Oil (Bbls)	Natural Gas (Mcf)	Oil (Bbls)	Natural Gas (Mcf)
Reserves, December 31, 2004	11,389,100	1,414,000,600	7,587,600		18,976,700	1,414,000,600
Extensions, discoveries and additions	5,516,300	680,671,500	370,600		5,886,900	680,671,500
Production	(464,300)	(61,722,300)	(1,556,300)		(2,020,600)	(61,722,300)
Revisions	(1,236,400)	(132,727,000)	(1,341,000)		(2,577,400)	(132,727,000)
Reserves, December 31, 2005	15,204,700	1,900,222,800	5,060,900		20,265,600	1,900,222,800
Extensions, discoveries and additions	3,962,000	505,773,000			3,962,000	505,773,000
Production	(594,100)	(78,395,500)	(1,603,400)		(2,197,500)	(78,395,500)
Revisions	(730,000)	(69,499,600)	529,200		(200,800)	(69,499,600)
Reserves, December 31, 2006	17,842,600	2,258,100,700	3,986,700		21,829,300	2,258,100,700
Extensions, discoveries and additions	6,091,000	747,914,000			6,091,000	747,914,000
Sales			(2,833,400)		(2,833,400)	
Production	(870,100)	(109,177,600)	(1,153,300)		(2,023,400)	(109,177,600)
Revisions	(232,000)	(54,182,200)			(232,000)	(54,182,200)
Reserves, December 31, 2007	22,831,500	2,842,654,900			22,831,500	2,842,654,900
Proved developed reserves: December 31, 2004	4,195,000	514,686,000	4,356,000		8,551,000	514,686,000
December 31, 2005	5,087,000	635,591,000	2,484,000		7,571,000	635,591,000

December 31, 2006	6,522,000	842,969,000	2,686,000	9,208,000	842,969,000
December 31, 2007	8,764,000	1,084,224,000		8,764,000	1,084,224,000

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 were $6.13, $4.50, and $8.00 per Mcf of natural gas at December 31, 2007, 2006 and 2005, respectively. The calculated weighted average oil price at December 31, 2007, 2006, and 2005 for Wyoming was $86.91, $59.95 and $60.81, respectively. The calculated weighted average crude oil price at December 31, 2006 and 2005 for China was a Duri price of $46.57 and $48.74, respectively. 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.

	United States	China	Total
As of December 31, 2005			
Future cash inflows	$ 16,124,248	$ 246,666	$ 16,370,914
Future production costs	(2,943,364)	(72,920)	(3,016,284)
Future development costs	(1,113,618)	(6,815)	(1,120,433)
Future income taxes	(4,110,554)	(30,235)	(4,140,789)
Future net cash flows	7,956,712	136,696	8,093,408
Discounted at 10%	(4,454,628)	(62,286)	(4,516,914)
Standardized measure of discounted future net cash flows	$ 3,502,084	$ 74,410	$ 3,576,494
As of December 31, 2006			
Future cash inflows	$ 11,239,526	$ 185,659	$ 11,425,185
Future production costs	(2,974,427)	(67,750)	(3,042,177)
Future development costs	(1,674,893)	(5,915)	(1,680,808)
Future income taxes	(2,217,709)	(6,710)	(2,224,419)
Future net cash flows	4,372,497	105,284	4,477,781
Discounted at 10%	(2,587,417)	(18,811)	(2,606,228)
Standardized measure of discounted future net cash flows	$ 1,785,080	$ 86,473	$ 1,871,553
As of December 31, 2007			
Future cash inflows	$ 19,411,520	$	$ 19,411,520
Future production costs	(4,233,952)		(4,233,952)
Future development costs	(2,100,647)		(2,100,647)
Future income taxes	(4,414,331)		(4,414,331)

Future net cash flows		8,662,590				8,662,590
Discounted at 10%		(4,793,188)				(4,793,188)
Standardized measure of discounted future net cash flows	$	3,869,402	$		$	3,869,402

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

Table of Contents

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31, 2007	December 31, 2006	December 31, 2005
Standardized measure, beginning	$ 1,871,553	$ 3,576,494	$ 1,669,336
Net revisions of previous quantity estimates	(126,447)	(185,419)	(436,425)
Extensions, discoveries and other changes	1,784,862	755,149	2,306,982
Sales of reserves in place	(46,451)		
Changes in future development costs	(254,538)	(193,004)	(130,727)
Sales of oil and gas, net of production costs	(496,556)	(482,659)	(426,891)
Net change in prices and production costs	1,607,811	(2,915,081)	1,992,707
Development costs incurred during the period that reduce future development costs	315,523	243,933	172,962
Accretion of discount	269,046	544,558	254,236
Net changes in production rates and other	11,007	(395,071)	
Net change in income taxes	(1,066,408)	922,653	(1,825,686)
Aggregate changes	1,997,849	(1,704,941)	1,907,158
Standardized measure, ending	$ 3,869,402	$ 1,871,553	$ 3,576,494

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 (US$000):

UNITED STATES

	Years Ended		
	December 31, 2007	December 31, 2006	December 31, 2005
Acquisition costs unproved properties	$ 7,780	$ 11,351	$ 775
Exploration	385,238	152,922	56,894
Development	304,782	317,118	208,173
Total	$ 697,800	$ 481,391	$ 265,842

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CHINA

	Years Ended December 31, 2007	December 31, 2006	December 31, 2005
Acquisition costs unproved properties	$ 10,356	$ 7,152	$ 2,876
Exploration			
Development	4,094	15,339	16,465
Total	$ 14,450	$ 22,491	$ 19,341

TOTAL

	Years Ended December 31, 2007	December 31, 2006	December 31, 2005
Acquisition costs unproved properties	$ 18,136	$ 18,503	$ 3,651
Exploration	385,238	152,922	56,894
Development	308,876	332,457	224,638
Total	$ 712,250	$ 503,882	$ 285,183

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

UNITED STATES

	Years Ended December 31, 2007	December 31, 2006	December 31, 2005
Oil and gas revenue	$ 566,638	$ 508,659	$ 448,731
Production expenses and taxes	(115,371)	(92,688)	(78,862)
Depletion and depreciation	(135,470)	(79,675)	(48,455)
Income taxes	(104,553)	(111,722)	(107,916)
Total	$ 211,244	$ 224,574	$ 213,498

CHINA

	Years Ended December 31, 2007	December 31, 2006	December 31, 2005
Oil and gas revenue	$ 64,822	$ 84,008	$ 67,762
Production expenses and taxes	(19,532)	(17,320)	(10,740)
Depletion and depreciation	(14,981)	(13,822)	(9,648)
Income taxes	(10,454)	(18,941)	(15,556)
Total	$ 19,855	$ 33,925	$ 31,818

Table of Contents

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

TOTAL

	Years Ended December 31, 2007	December 31, 2006	December 31, 2005
Oil and gas revenue	$ 631,460	$ 592,667	$ 516,493
Production expenses and taxes	(134,903)	(110,008)	(89,602)
Depletion and depreciation	(150,451)	(93,497)	(58,103)
Income taxes	(115,007)	(130,663)	(123,472)
Total	$ 231,099	$ 258,499	$ 245,316

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

	December 31, 2007	December 31, 2006
Developed Properties:		
Acquisition, equipment, exploration, drilling and environmental costs Domestic	$ 1,868,564	$ 1,174,683
Acquisition, equipment, exploration, drilling and environmental costs China		96,875
Less accumulated depletion, depreciation and amortization Domestic	(330,813)	(196,683)
Less accumulated depletion, depreciation and amortization China		(26,566)
	1,537,751	1,048,309
Unproven Properties:		
Acquisition and exploration costs Domestic	36,778	28,998
Acquisition and exploration costs China		42,062
	$ 1,574,529	$ 1,119,369

Table of Contents

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

None.

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

Management s Report on Assessment of Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company as such term is defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act). In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act, management has conducted an assessment of the effectiveness of the Company s internal control over financial reporting as of December 31, 2007, using the criteria in Internal Control Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). 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.

Based on the results of this assessment, management (including our chief executive officer and our chief financial officer) has concluded that, as of December 31, 2007, our internal control over financial reporting was effective. 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.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2007 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, 2007. 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, 2007.

The Company has adopted a code of ethics that applies to the Company s Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. The full text of such code of ethics is posted on the Company s website at www.ultrapetroleum.com, and is available free of charge in print to any shareholder who requests it. Requests for copies should be addressed to the Secretary at 363 North Sam Houston Parkway East, Suite 1200, Houston, Texas 77060.

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

The information required by this item is incorporated herein by reference to the Company s definitive proxy statement, which will be filed not later than 120 days after December 31, 2007.

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

The information required by Item 403 of Regulation S-K will be included in the Company s definitive proxy statement, which will be filed not later than 120 days after December 31, 2007 and is incorporated herein by reference.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

The information required by this item is incorporated herein by reference to the Company s definitive proxy statement, which will be filed not later than 120 days after December 31, 2007.

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, 2007.

Part IV

Item 15. ***Exhibits, Financial Statement Schedules.***

The following documents are filed as part of this report:

1. *Financial Statements:* See Item 8.

2. *Financial Statement Schedules:* None.

3. *Exhibits.* The following Exhibits are filed herewith pursuant to Rule 601 of the Regulation S-K or are incorporated by reference to previous filings.

Exhibit Number	Description
3.1	Articles of Incorporation of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.1 of the Company s Quarterly Report on Form 10-Q for the period ended June 30, 2001).
3.2	By-Laws of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.2 of the Company s Quarterly Report on Form 10-Q for the period ended June 30, 2001).
3.3	Articles of Amendment to Articles of Incorporation of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.3 of the Company s Report on Form 10-K/A for the period ended December 31, 2005)
4.1	Specimen Common Share Certificate (incorporated by reference to Exhibit 4.1 of the Company s Quarterly Report on Form 10-Q for the period ended June 30, 2001).
4.2	Form 8-A filed with the Securities and Exchange Commission on July 23, 2007.
10.1	Credit Agreement dated as of April 30, 2007 among Ultra Resources, Inc., JPMorgan Chase Bank, N.A. as Administrative Agent, J.P. Morgan Securities Inc. as Sole Bookrunner and Sole Lead Arranger, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company s Quarterly Report on Form 10-Q for the period ended March 31, 2007).
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).
14.1	Code of Ethics for Chief Executive Officer and Senior Financial Officers of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.3 of the Company s Annual Report on Form 10-K for the year ended December 31, 2003).
*21.1	Subsidiaries of the Company.
*23.1	Consent of Netherland, Sewell & Associates, Inc.
*23.2	Consent of Ryder Scott Company.
*23.3	Consent of Ernst & Young LLP.
*23.4	Consent of KPMG 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.

* Filed herewith

Table of Contents

SIGNATURES

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

ULTRA PETROLEUM CORP.

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

Date: February 22, 2008

Signature	Title	Date
/s/ Michael D. Watford Michael D. Watford	Chairman of the Board, Chief Executive Officer, and President (principal executive officer)	February 22, 2008
/s/ Marshall D. Smith Marshall D. Smith	Chief Financial Officer (principal financial officer)	February 22, 2008
/s/ Garland R. Shaw Garland R. Shaw	Corporate Controller (principal accounting officer)	February 22, 2008
/s/ W. Charles Helton W. Charles Helton	Director	February 22, 2008
/s/ Stephen J. McDaniel Stephen J. McDaniel	Director	February 22, 2008
/s/ Robert E. Rigney Robert E. Rigney	Director	February 22, 2008
/s/ Roger A. Brown Roger A. Brown	Director	February 22, 2008

79

EXHIBIT INDEX

Exhibi Number	Description
3.1	Articles of Incorporation of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.1 of the Company s Quarterly Report on Form 10-Q for the period ended June 30, 2001).
3.2	By-Laws of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.2 of the Company s Quarterly Report on Form 10-Q for the period ended June 30, 2001).
3.3	Articles of Amendment to Articles of Incorporation of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.3 of the Company s Report on Form 10-K/A for the period ended December 31, 2005)
4.1	Specimen Common Share Certificate (incorporated by reference to Exhibit 4.1 of the Company s Quarterly Report on Form 10-Q for the period ended June 30, 2001).
4.2	Form 8-A filed with the Securities and Exchange Commission on July 23, 2007.
10.1	Credit Agreement dated as of April 30, 2007 among Ultra Resources, Inc., JPMorgan Chase Bank, N.A. as Administrative Agent, J.P. Morgan Securities Inc. as Sole Bookrunner and Sole Lead Arranger, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company s Quarterly Report on Form 10-Q for the period ended March 31, 2007).
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).
14.1	Code of Ethics for Chief Executive Officer and Senior Financial Officers of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.3 of the Company s Annual Report on Form 10-K for the year ended December 31, 2003).
*21.1	Subsidiaries of the Company.
*23.1	Consent of Netherland, Sewell & Associates, Inc.
*23.2	Consent of Ryder Scott Company.
*23.3	Consent of Ernst & Young LLP.
*23.4	Consent of KPMG 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.

* Filed herewith