ULTRA PETROLEUM CORP
Form 10-K
March 31, 2006

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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, 2005.

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	American 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 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 or a non-accelerated filer. See definition of accelerated filer large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ Accelerated filer o Non-accelerated filer 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 $4,650,667,733 as of June 30, 2005 (based on the last reported sales price of $30.36 of such stock on the American Stock Exchange on such date).

As of February 28, 2006, there were 155,235,864 common shares of the registrant outstanding.

Documents incorporated by reference: The definitive Proxy Statement for the 2006 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2005, is incorporated by reference in Part III of this Form 10-K.

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Certain Definitions

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

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

Bcf   One billion cubic feet of natural gas.

Bcfe   One billion cubic feet of natural gas equivalent.

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

BTU   British Thermal Unit.

CFD   Caofaedian   the Chinese designation for the area in Bohai Bay area in the vicinity of the 04/36 and 05/36 Blocks, offshore China.

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.

ICP   Indonesian Crude Price.

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 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 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.

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 gas production attributable to the proved reserves estimated in its independent engineer s reserve report for the prices it received for the production on the date of the report, unless it had a contract to sell the production for a different price. 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 tax rates.

Terms used to classify the Company s reserve quantities

The Securities and Exchange Commission (SEC) definition of proved oil and gas reserves, per Article 4-10(a)(2) of Regulation S-X, is as follows:

Proved oil and gas reserves. Proved oil and 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. 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.

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.

Terms used to describe the legal ownership of the Company s oil and 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 gas companies use seismic data as their principal source of information to locate oil and 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

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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 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 gas properties. The Company was incorporated on November 14, 1979, under the laws of the Province of British Columbia, Canada. The Company continued into the Yukon Territory, Canada under Section 190 of the *Business Corporations Act* (Yukon Territory) on March 1, 2000. The Company s operations are focused primarily in the Green River Basin of southwest Wyoming and Bohai Bay, offshore China. From time to time, the Company evaluates other opportunities for the acquisition, exploration and development of oil and gas properties.

As of December 31, 2005, Ultra owns interests in approximately 148,007 gross (78,688 net) acres in Wyoming covering approximately 230 square miles. The Company owns working interests in approximately 330 gross productive wells in this area and is operator of 53% of the 330 gross wells. The Company s current domestic operations are focused on developing and expanding a tight gas sand project located in the Green River Basin in southwest Wyoming. In 2005, the Company s Wyoming production was approximately 87.4% of the Company s total oil and natural gas production on an MCFE basis and 98.5% of the Company s estimated net proved reserves were in Wyoming on an MCFE basis. In 2005, capital expenditures in Wyoming comprised approximately 93% of the Company s total capital expenditures.

Following the acquisition of Pendaries Petroleum Ltd. (Pendaries) on January 16, 2001, the Company became active in oil and gas exploration and development covering the 04/36 Block and the 05/36 Block (jointly the Blocks) in Bohai Bay, China. The Company currently holds an 18.18% exploration interest in the 04/36 Block. Upon initiation of development, the interest reduced to an 8.91% working interest in field development and production areas. Originally, the Company held a 15.00% exploration interest in the 05/36 Block which reduced, upon initiation of development, to a 7.35% working interest for development and production areas. In 2004, an extension of the 05/36 Block exploration term was granted (from February 28, 2005 to February 28, 2006). One of the parties to the contract elected not to participate in this extension of the exploration phase. The Company chose to acquire this available exploration interest. As a result, the Company holds a 23.08% exploration interest in the 05/36 Block, which will be reduced to 11.31% for areas that may be developed in the current exploration acreage.

There are currently three fields (CFD 11-6, 12-1, 12-1S) under development (located in close proximity and thus developed under a single development plan) within the Blocks that have been unitized because the fields are located in both the 04/36 and 05/36 Blocks. A Unitization Agreement was executed that assigned the Company a 7.82% working interest in the combined field unit. The Company s interest in the unit was based upon the original 15.00% exploration interest in the 05/36 Block and an 18.18% exploration interest of the 04/36 Block. On July 19, 2004, oil production began from the CFD 11-1 and 11-2 fields and on July 5, 2005, oil production began from the CFD 11-3 and 11-5 fields. All four fields are located in the 04/36 Block. In 2005, the Company spent approximately 7% of its total 2005 capital budget on developing these China fields, as well as on engineering work focused on development of additional fields and continuing exploration. A wholly-owned subsidiary of Kerr-McGee Corporation is the operator of the Blocks. At the time of the Pendaries acquisition, there were three oil discoveries on the Blocks. Since then, six new discoveries have been made. Four of these oil fields are developed and on production and three additional fields are being developed.

The Company also owns interests in 26,868 gross (24,610 net) acres in Pennsylvania. The Company drilled 1 gross (1.0 net) test well on this acreage during 2005. This well has been completed and is waiting on a pipeline connection. Evaluation is ongoing to determine plans for future activity in the area. In Texas, the Company owns a minor non-operated interest in 1 gross (0.12 net) producing well, plus the associated 80 gross (14 net) acres. The Company is currently attempting to divest this property.

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 we make 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

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Investor Relations tab on the Company s website. The Company s SEC filings are available on its website as soon as they are posted to the EDGAR database on the SEC s website.

Business Strategy

Green River Basin, Wyoming

The Company will continue the ongoing program to identify, develop and explore the acreage position now held in the tight gas sand trend in the Green River Basin. The majority of the wells in the 2006 drilling program will be targeting 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 will continue to drill 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 area. In addition to the ongoing efforts in the Lance Pool section, the Company is continuing to evaluate the deeper, potentially productive, zones found on its acreage block below the Lance Pool. 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.

Bohai Bay, China

In 2006, the Company plans to continue producing oil at the CFD 11-1, 11-2, 11-3 and 11-5 fields, continue development on the CFD 11-6, 12-1 and 12-1S unitized fields and drill additional exploration wells. The Company has nine discovered oil fields in the Bohai Blocks. The first two fields, CFD 11-1 and 11-2, began producing in July 2004, while the CFD 11-3 and 11-5 fields began producing in July 2005. Three additional fields are currently being developed and are scheduled to go on production during the second half of 2006, bringing the total to seven producing fields by the end of 2006. Two discoveries remain in the appraisal stage.

Pennsylvania

The Company will continue to evaluate the initial test well including production testing to sales. The Company continues to acquire additional acreage, seismic and geologic data in the area. Any decision as to future drilling on the prospect is pending production testing of the initial well and ongoing geological, geophysical and engineering studies.

Marketing and Pricing

The Company 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. To a lesser extent, the Company derives revenues from the sale of its share of oil production from its producing fields in the Bohai Bay area, offshore China. 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, as well as prevailing prices for crude oil produced in the Bohai Bay region of China. 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 accurately predict or control the market prices that it receives for the sale of its natural gas, condensate, or oil production. However, the Company has, in the regular course of its business, from time to time, hedged a portion of its natural gas production primarily through the use of fixed price, forward sales of physical gas, or through the limited 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. The Company has not, to date, hedged any of its Chinese oil production; although, it may do so in the future. 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 amounts 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 the spot prices that it would have received.

Natural Gas Marketing

The Company 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 (daily, monthly and longer term). The Company s customers are situated in the western United States primarily California and the Pacific Northwest, as well as the Front Range area of Colorado and in Utah. The sale of the Company s natural gas is as produced , and 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 natural gas sales.

During 2005, the Company negotiated several significant new or amended gathering and processing agreements with various midstream service providers that gather, compress and/or process natural gas owned or controlled by the Company from its producing wells in the Pinedale Anticline and Jonah Fields in southwest Wyoming. These agreements provide that the respective midstream service providers expand the capacities of their facilities in southwest Wyoming to accommodate growing volumes from wells in which the Company owns an interest. Most of these agreements or amendments contain multi-year commitments for midstream services. In more than one instance, the Company was able to substantially lower some of the fees that it pays for such midstream services, in exchange for committing to these longer term arrangements. The capacity of the midstream infrastructure related to the Company s production continues to be adequate to allow it to sell essentially all of its available production.

During 2005, the Company realized natural gas prices that were higher than those historically seen 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 beyond the ability of the Company to control or to predict. These factors include weather, natural gas supplies, natural gas demand, and pipeline export capacity. A hotter than normal summer, plus the impact of two major hurricanes (Katrina and Rita) on natural gas production from the Gulf of Mexico, caused natural gas prices in the Rocky Mountain Region, and other parts of the country, to increase during the third and fourth quarters of 2005.

Because production exceeds local demand for natural gas, the Rocky Mountain Region is usually a net-exporter of natural gas. Historically, natural gas production in southwest Wyoming has 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 pricing reference point in south Louisiana in the past. As a result, during that time period, the Company realized prices that were significantly lower than those received by companies with production in other regions of the U.S. Significant increases in pipeline capacity to transport production from the Rockies production areas to markets in the West in recent years have served to improve (i.e. lower) basis differentials for Wyoming natural gas production. (Examples include: Kern River Pipeline in service May 2003, and the Cheyenne Plains Pipeline in service February 2005). These expansions of pipeline export capacity have, in the past, reduced but not eliminated the basis differential for natural gas prices in southwest Wyoming when compared to prices at the Henry Hub pricing reference point. There have been, from time to time, numerous other proposed pipeline projects that have been announced to transport Rockies and Wyoming natural gas production to markets.

During 2005, the Company took a major step toward assuring that the pipeline infrastructure to move the Company s natural gas supplies away from southwest Wyoming will 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 the proposed Rockies Express Pipeline project, sponsored by subsidiaries of Kinder Morgan and Sempra Energy. The Rockies Express Pipeline, if built as proposed, would be the largest natural gas transmission pipeline project of its type built in the United States in more than 20 years, beginning at the Opal Processing Plant in southwest Wyoming and traversing Wyoming and several other states to an ultimate terminus in eastern Ohio. This project is projected to cover more than 1,800 miles and is contemplated to be a large-diameter (42), high-pressure natural gas pipeline. The Rockies Express Pipeline, if built, will be an interstate pipeline and would therefore be subject to the jurisdiction of the United States Federal Energy Regulatory Commission (FERC).

On December 19, 2005, the Company signed two Precedent Agreements (Precedent Agreements) with Rockies Express Pipeline, LLC 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 Rockies Express Pipeline, LLC 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 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 the Rockies Express Pipeline, LLC 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 anticipated to be completed in stages between 2007 and 2009. Although the Company is optimistic that the Rockies Express Pipeline project will receive the necessary regulatory approvals and be constructed in a timely manner, there can be no assurances that the Rockies Express Pipeline will be built, nor will there be any assurances that, if built, it will prevent large basis differentials from occurring in the future.

Oil Marketing

Through its wholly-owned Sino-American Energy Corporation subsidiary, the Company continued to market its share of oil production from the CFD 11-1 and 11-2 fields during 2005. In addition, the next two of its fields in Block 04/36 Bohai Bay, offshore China (CFD 11-3 and 11-5), began producing oil in July 2005.

The sale of the Company s Chinese oil production (CFD crude) is done on a tanker/cargo lifting basis. As the Company s share of inventories on the CFD 11-1 and 11-2 and 11-3 and 11-5 fields Floating Production Storage and Offloading Vessel (FPSO) become sufficient to schedule a lifting (typically 200,000 300,000 barrels per cargo), the Company coordinates with the operator and its markets to lift a cargo. By necessity, the Company will, from time to time, carry inventories of crude oil to accommodate the lifting schedules for its share of oil from the FPSO. Each of the partners in the CFD 11-1/11-2 and 11-3/11-5 fields are responsible for the disposition of their respective share of the CFD crude production. Kerr-McGee, as operator of these fields, manages the lifting schedule for production from these fields. The Company has sold most of its share of the CFD crude production to an affiliate of its Chinese partner, Chinese National Offshore Oil Corporation (CNOOC) China, Ltd., at prices that reflect a slight discount to the Indonesian Crude Price (ICP) Duri monthly average price. In 2005, for the first time, the Company sold some of its share of the CFD crude production outside of China, and it continues to assess its opportunities to market its share of the CFD crude production to other markets such as Korea, Japan and Singapore. The Company does not have any outstanding, uncollectible accounts for CFD crude oil sales as of December 31, 2005.

Currently, the CFD crude is a heavy, sweet crude oil, with an API gravity of approximately 19 degrees. The production from these first four fields is from multiple productive reservoirs, which have variability in the quality of oil. The Company believes that the quality of the oil produced from these fields will tend to improve as additional wells and reservoirs are completed and placed into production. Due to its quality and physical characteristics, refiners and other markets for the CFD crude oil typically expect to be able to purchase CFD crude at prices that are lower than light sweet crude oils like West Texas Intermediate or Brent. Oil produced and sold from the four CFD fields is typically priced based upon the monthly official ICP for Duri field crude. The Duri crude, produced in Indonesia, is of similar quality to the CFD crude produced in the Bohai Bay area.

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The official ICP Duri price is a monthly weighted average of three, independent daily assessments of the price of Duri crude, reported by Platt s Asian Petroleum Price Index published by Seapac Services Limited, and RIM Intelligence Co. To the monthly official ICP Duri marker price, a premium or discount is added to reflect transportation and quality differentials for the CFD crude relative to the Duri marker crude. The premium or discount for the CFD crude (relative to the Duri price) is negotiated monthly between the Company and its partners, including CNOOC.

Environmental Matters

In 1998, the U.S. Bureau of Land Management (BLM) initiated a requirement for an Environmental Impact Statement (EIS) for the Pinedale Anticline area in the Green River Basin. An EIS evaluates the effects that an industry s activities will have on the environment in which the activity is proposed. This EIS encompasses the area north of the Jonah Field, including the Pinedale Anticline, which is where most of the Company s exploration and development is taking place. This environmental study included an analysis of the geological and reservoir characteristics of the area plus the necessary environmental studies related to wildlife, surface use, socio-economic and air quality issues. On July 27, 2000, the BLM issued its Record of Decision (ROD) with respect to the final EIS. The ROD/ EIS allows for the drilling of 700 producing surface locations within the area covered by the EIS, but does not authorize the drilling of particular wells. Ultra must submit applications to the BLM s Pinedale field manager for permits to drill and for other required authorizations, such as rights-of-way for pipelines, for each specific well or pipeline location. Development activities in the Pinedale Anticline area, as on all federal leaseholds, remain subject to regulatory agency approval. In making its determination on whether to approve specific drilling or development activities, the BLM applies the requirements outlined in the ROD/ EIS.

The ROD/ EIS imposes limitations and restrictions on activities in the Pinedale Anticline area, including 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/ EIS also provides for annual reviews to compare actual environmental impacts to the environmental impacts projected in the EIS and provides for adjustments to mitigate such impacts, if necessary. The review team is comprised of operators, local residents and other affected persons. The Company cannot predict if or how these changes may affect permitting, development and compliance under the ROD/EIS. 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.

As of December 31, 2005, the Company had approximately 46 well locations with respect to which both the BLM and the WOGCC have approved permits to drill on Company-operated federal leases in the Pinedale Anticline and Jonah field areas.

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 substantial. Further, any additional limitations and mitigation measures could further increase production costs, delay exploration, development and production activities and curtail exploration, development and production activities altogether.

The Company also co-owns leases on state and privately owned lands in the vicinity of the Pinedale Anticline that do not fall under the jurisdiction of the BLM and are not subject to the EIS requirement.

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 is 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. Prior to these approvals, the

Company had drilled 21 gross (7.7 net) wells in the field. Since the increased density approvals, the Company has drilled an additional 22 gross (14.0 net) wells in the field. All 43 wells drilled by the Company in the Jonah Field have been productive. Since this time 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 is currently conducting a new EIS covering the Jonah Field to assess the impacts of this increased density development and define the parameters under which this increased density development will be allowed to proceed. The draft EIS was made available mid-February 2005. After review and comment by all parties the BLM is now preparing the final ROD. It is expected that the ROD for the new Jonah EIS should be issued during the first half of 2006.

During 2003, 2004 and 2005, Ultra and other operators in the Pinedale Field received approval from the WOGCC to drill increased density pilot project wells in several areas of the Pinedale Field. These pilot projects are designed to test the feasibility of developing this field in well densities greater than the currently approved one well per 40 acres. The results of some of this work led to the WOGCC in July 2004 approving the development of the northern portion of the anticline on a two wells per 40 acre density. The acreage is operated by Questar Exploration and Production Company (Questar), a working interest partner of the Company, and the Company owns a working interest in the majority of this acreage. This approval covers approximately 14,432 gross acres. Since this time, additional increased density pilot wells have been drilled by Ultra and others on the pilot areas within the Pinedale field. Based on the data gathered through these pilot projects, the WOGCC approved several additional Increased Density applications during 2005. In August 2005, approval was granted for development of a significant portion of the northern portion of the Pinedale field for drilling on a four wells per 40 acre density. This approval covers approximately 11,256 gross acres in which Ultra owns an interest and are operated by Questar. In November 2005, approval was granted for development of a significant portion of the central Pinedale Field and surrounding area on a two wells per 40 acre density. This approval covers approximately 23,816 gross acres in which Ultra owns an interest. Ultra operates the majority of the acreage covered by this approval. Further drilling within these areas and the other pilot areas approved for increased density continues and the results of these are being evaluated to determine the appropriate course of action as to the overall development strategy for the Pinedale Field.

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

The BLM approved the Questar proposal after considering extensive input from the participating agencies received during the public comment process. Key components of the approval are: 1) One pad with two drilling rigs during the winter of 2004-2005; 2) three pads with two drilling rigs per pad in the winter of 2005-2006 and thereafter through the winter of 2013/2014; 3) activities during the May-November period will continue to be governed by the original Pinedale Anticline EIS; 4) directional drilling with up to 16 wells per pad resulting in only one-third of the drilling phase surface disturbance contemplated under the original EIS; 5) construction of a produced water and condensate gathering system in 2005; 6) funding for continued monitoring of mule deer and other critical wildlife for the duration of development activity; 7) use of flareless-completion technology to reduce noise, air and visual pollution during well-completion operations; 8) funding for air-quality monitoring; and 9) wildlife habitat enhancement as well as other monitoring and mitigation measures described in the BLM decision record.

Questar has met their commitments under the terms of this approval and is now proceeding with the winter drilling program as proposed. Currently there are six Questar operated drilling rigs operating within the

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area of this approval, two rigs on each of three separate winter pads. These wells will be drilled to total depth, logged and cased during the winter restriction period with completion activity to commence in the spring with the lifting of the normal seasonal wildlife restrictions.

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 would be able to operate a total of six rigs, two each on three different winter pads. During this winter demonstration project, the Proponents plan to employ 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 in the form of a FONSI ruling from the BLM in September 2005. The proponents began activities in the winter demonstration project in November 2005 and are currently running the six rigs as proposed. The FONSI ruling 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 FONSI 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 have now 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 is proceeding and impacts of the development proposal will be analyzed to assess alternative considerations and mitigation requirements that should be considered as alternatives to those included in the proposal or in addition to those measures now proposed. The proposed action includes commitments to reduce surface disturbance by utilizing fewer overall pads and drilling more directional wells than called for in the PAPA ROD. Also, if approved, the Proponents proposal commits to reduced air emissions. The Proponents have proposed to apply technology to drilling rig engines to reduce emissions, to reduce vehicle traffic by installing a liquids gathering system as appropriate in the field, and by expanding the use of telemetry to reduce production operations traffic requirements. The Proponents have also proposed additional monitoring to assess benefits of mitigation activities on the impacts of development activities on the wildlife in the project area. The proposal commits to offsite mitigation measures should the monitoring indicate it is warranted. If approved, the Proponents proposal commits to reduced reserve pit use and to accelerated surface reclamation. The SEIS process calls for a ROD in late 2006.

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 gas production depends upon numerous factors beyond the Company s control. These factors may include state and federal regulation of oil and 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 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 gas, protect rights to produce oil and gas between owners in a common reservoir, control the amount of oil and gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines and natural gas plants 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 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 are not clear.

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.

In the event 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, certain of such 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 at some time in the future might be determined to be non-reciprocal under the Mineral Act.

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

Environmental Regulations

General. The Company s activities in the United States are subject to existing federal, state and local laws and regulations governing environmental quality, oil spills and pollution control and its activities in China are subject to the laws and regulations of China. It is anticipated that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations governing the

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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.

The Company s activities with respect to exploration, drilling and production 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 environmental regulation by state and federal authorities, including the Environmental Protection Agency (EPA). Such regulation can increase the cost of planning, designing, installing and operating such facilities. In most instances, the regulatory requirements relate to water and air pollution control measures.

Solid and Hazardous Waste. The Company currently owns or leases, and has in the past owned or leased, numerous properties that have been used for the exploration and production of oil and gas for many years. Although the Company utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other solid wastes may have been disposed of or released on or under the properties that the Company currently owns or leases or properties that the Company has owned or leased or on or under locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties over whom the Company had no 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 gas wastes and properties have gradually become stricter over time. Under new laws, the Company could be required to remediate property, including ground water, containing or impacted by previously disposed wastes (including wastes disposed of or released by prior owners or operators) or to perform remedial plugging operations to prevent future, or mitigate existing, contamination.

The Company may generate wastes, including hazardous wastes that are subject to the federal Resource Conservation and Recovery Act (RCRA) and comparable state statutes. The EPA and various state agencies have limited the disposal options for certain wastes, including wastes designated as hazardous under the RCRA and state analogs (Hazardous Wastes) and is considering the adoption of stricter disposal standards for non-hazardous wastes. Furthermore, certain wastes generated by the Company s oil and 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, generally imposes joint and several liability 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. To its knowledge, the Company has not been named a PRP under CERCLA nor have any prior owners or operators of its properties been named as PRP s related to their ownership or operation of such property.

National Environmental Policy Act. The federal National Environmental Policy Act provides that, for those federal actions that are major federal actions significantly affecting the quality of the human environment, the federal agency taking such action must follow certain steps in evaluating the environmental impacts of the federal action. This evaluation generally takes the form of an EIS. In the EIS, the agency is required to evaluate alternatives to the proposed action and the environmental impacts of the alternatives.

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Actions such as drilling on federal lands, to the extent the drilling requires federal approval, likely trigger the requirements of the National Environmental Policy Act, with few exceptions. Certain of the Company s activities may trigger these requirements. The requirements of the National Environmental Policy Act may result in increased costs, significant delays and the imposition of restrictions or obligations, including the restriction or prohibition of drilling, upon the 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 joint and several liability, 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, we may 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 require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control hazardous (toxic) air pollutants, might require installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could bring lawsuits for civil penalties or require the Company to forego construction, modification or operation of certain air emission sources.

Clean Water Act. The CWA imposes restrictions and strict controls regarding the discharge of wastes, including produced waters and other oil and natural gas wastes, into waters of the United States, a term broadly defined. These controls have become more stringent over the years, and it is probable that additional restrictions will be imposed in the future. Permits must be obtained to discharge pollutants into federal waters. The CWA provides for civil, criminal and administrative penalties for unauthorized discharges of pollutants and of oil and hazardous substances. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or hazardous substances. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters. In addition, the EPA has promulgated regulations that may require the Company to obtain permits to discharge storm water runoff, including discharges associated with construction activities. In the event of an unauthorized discharge of wastes, the Company may be liable for penalties and costs.

Endangered Species Act. The Endangered Species Act (ESA) was established to provide a means to conserve the ecosystems upon which endangered and threatened species depend, to provide a program for conservation of these endangered and threatened species, and to take the appropriate steps that are necessary to bring any endangered or threatened species to the point where measures provided for in the ESA are no longer necessary. The Company conducts operations on federal oil and gas leases that have species, such as sage grouse or other sensitive species, that potentially could be listed as threatened or endangered under the ESA. If a species is listed as threatened or endangered, 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 gas development. If the Company were to have a portion of its leases designated as critical or suitable habitat, it may adversely impact the value of the affected leases.

OSHA and other Regulations. The Company is subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state

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statutes require us 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, 2005, the Company had 57 full time employees, including officers.

Item 1A. *Risk Factors.*

There are inherent limitations in all control systems, and misstatements due to error or fraud that could seriously harm our business may occur and not be detected.

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 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 certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, a control may be inadequate because of changes in conditions or the degree of compliance with the policies or procedures may deteriorate. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. A failure of our controls and procedures to detect error or fraud could seriously harm our business and results of operations.

Our reserve information represents estimates that 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 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 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 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 gas prices have fluctuated widely.

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

The Company competes with numerous other companies in virtually all facets of its business. The competitors in development, exploration, acquisitions and production include major integrated oil and gas companies as well as numerous independents, including many that have significantly greater resources.

Therefore, competitors may be able to pay more for desirable leases and evaluate, bid for and purchase a greater number of properties or prospects than the financial or personnel resources of the Company permit. The ability of the Company to increase reserves in the future will be dependent on its 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

the location of, and our ability to access platforms, pipelines and other facilities used to produce and transport oil and gas production;

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

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

the extent of domestic production and imports of oil and natural gas;

the availability of pipeline capacity;

the effects of inclement weather;

the demand for oil and natural gas by utilities and other end users;

the availability of alternative fuel sources;

the proximity of natural gas production to natural gas pipelines;

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, the Company may be unable to market all of the oil and natural gas that it produces, including oil and natural gas that may be produced from the Bohai Bay properties in China. In addition, the Company may be unable to obtain favorable prices for the oil and natural gas it produces.

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

In 2005, the Company had three significant customers, CNOOC, Occidental Energy Marketing, Inc. and Sempra Energy Trading, that individually accounted for 10% or more of the Company s total natural gas and oil sales. To the extent these or any other significant customer reduces the volume of its oil or gas purchases from us, we could experience a temporary interruption in sales of, or a lower price for, our oil and natural gas.

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

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, as well as prevailing prices for crude oil produced in the Bohai Bay region of China. 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 accurately predict or control the market prices that it receives for the sale of its natural gas, condensate, or oil production.

Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the Company s control. 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 gas, the price of foreign oil and gas imports and the availability of alternate fuel sources and transportation interruption. Any substantial and extended decline in the price of oil or gas could have an adverse effect on the carrying value of the Company s proved reserves, borrowing capacity, the Company s ability to obtain additional capital, and the Company s revenues, profitability and cash flows from operations.

Volatile oil and 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 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 the Company s Wyoming production than production in other U.S. regions.

The price of natural gas in the southwest Wyoming region is critical to the Company s 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 in the summer months for natural gas in the Rocky Mountain region of the United States. Therefore, a price decrease may more adversely affect the price received for the Company s Wyoming production than production in the other U.S. regions. There have been, 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. There can be no assurance that such infrastructure will be built or that if built, it will prevent large basis differentials from occurring in the future.

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

The Company s 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 the Company 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;
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells; and
- require governmental approval of the overall development plan prior to the start of development of fields in China.

Under these laws and regulations, the Company could be liable for personal injury and clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. The Company maintains limited insurance coverage for sudden and accidental environmental damages, but does not maintain insurance coverage for the full potential liability that could be caused by sudden and accidental environmental damages. Accordingly, the Company may be subject to liability or may be required to cease production from properties in the event of environmental damages.

A significant percentage of the Company s 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 agencies. A portion of the Company s 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, the Company is 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 the Company s ability to complete its drilling program at the cost and in the time period currently 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.

The Company s ability to continue exploration and development of its properties and to replace reserves may be dependent upon its ability to continue to raise significant additional financing, including debt financing that may be significant, or obtain some other arrangements with industry partners in lieu of raising financing. Any arrangements that may be entered into could be expensive to the Company. There can be no assurance that the Company will be able to raise additional capital in light of factors such as the market demand for its securities, the state of financial markets for independent oil and gas companies (including the markets for debt), oil and 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 the Company s capital budget.

The Company expects to continue using its bank credit facility to borrow funds to supplement its available cash flow. The amount the Company may borrow under the credit facility may not exceed a borrowing base determined by the lenders based on their projections of the Company s future production, future production costs and taxes, commodity prices and other factors. The Company cannot control the assumptions the lenders use to calculate the borrowing base. The lenders may, without the Company s consent, adjust the borrowing base at any time. If the Company s borrowings under the credit facility exceed the borrowing base, the lenders may require that the Company repay the excess. If this were to occur, the Company may have to sell assets or seek financing from other sources. The Company can make no assurances that it 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.

The Company s operations may be interrupted by severe weather, particularly in the Rocky Mountain region.

The Company s operations are conducted principally in the Rocky Mountain region of the United States. The weather in this area can be extreme and can cause interruption in the Company s exploration and production operations. Moreover, especially severe weather can result in damage to facilities entailing longer operational interruptions and significant capital investment. Likewise, the Company s Rocky Mountain operations are subject to disruption from winter storms and severe cold, which can limit operations involving fluids and impair access to the Company s facilities. A portion of the Company s acreage is affected by winter lease stipulations that restrict the period of time during which operations may be conducted on the leases. The Company s leases that are affected by the winter stipulations 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.

The Company has historically invested a significant portion of its capital budget in drilling exploratory wells in search of unproved oil and gas reserves. The Company cannot be certain that the exploratory wells it drills will be productive or that it will recover all or any portion of its investments. In order to increase the chances for exploratory success, the Company often invests in seismic or other geoscience data to assist it in identifying potential drilling objectives. Additionally, the cost of drilling, completing and testing exploratory wells is often uncertain at the time of the Company s initial investment. Depending on complications encountered while drilling, the final cost of the well may significantly exceed that which the Company originally estimated. The Company uses 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 the Company s proved reserves.

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

The Company s future success may depend on its ability to find, develop and acquire additional oil and gas reserves that are economically recoverable. Without successful exploration, development or acquisition activities, the Company s reserves and production will decline. The Company can give no assurance that it 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 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 operated or owned (in whole or in part) by the Company could have a material adverse impact on the Company. The Company and the operators of its 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 the Company s financial condition.

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

The Company s oil and gas operations are subject to all of the risks and hazards typically associated with drilling for, and production and transportation of, oil and 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 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 the Company s investment in such activity. If oil or 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 and we may decide to alter our drilling schedule or not drill at all.

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

- receipt of additional seismic data or reprocessing of existing data;
- material changes in oil or 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 or, in the case of CNOOC, approval of expenditures for budget purposes;
- the Company s ability to attract other industry partners to acquire a portion of the working interest to reduce exposure to costs and drilling risks;
- decisions of the Company s joint working interest owners; and
- the BLM s interpretation of an EIS and the results of the permitting process.

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

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

The Company follows the full cost method of accounting for its oil and gas properties. A separate cost center is maintained for expenditures applicable to each country in which the Company conducts 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 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 gas prices increase the ceiling applicable to future periods. Future price decreases could result in reductions in the carrying value of such assets and an equivalent charge to earnings.

We are not the operator, and have limited influence over the operations, of our Bohai Bay properties.

Because the Company is not the operator and holds a minority interest, it cannot control the pace of exploration or development in the Bohai Bay properties or major decisions affecting the drilling of wells or the plan for development and production, although contract provisions give the Company certain consent rights in some matters. Kerr-McGee s influence, as operator, over these matters can affect the pace at which the Company spends money on this project. If Kerr-McGee were to shift its focus from this project, the pace of development could slow down or stop altogether. On the other hand, if Kerr-McGee were to decide to accelerate development of this project, the Company could be required to fund its share of costs at a faster pace than anticipated, which might exceed its ability to raise funds. If, because of this, the Company were unable to pay its share of costs, it could lose or be forced to sell its interest in the Bohai Bay properties or be forced to not participate in the exploration or development of specific prospects or fields, potentially diminishing the value of its Bohai Bay assets.

Political, economic or legal factors associated with our ownership of properties in China could impact the results of our operations.

Ownership of property interests and production operations in areas outside the United States are subject to various risks inherent in foreign operations. These risks may include:

- loss of revenue, property and equipment as a result of expropriation, nationalization, war or insurrections;
- increases in taxes and governmental royalties;
- renegotiation of contracts with governmental entities and quasi-governmental agencies;
- change in laws and policies governing operations of foreign based companies;
- labor problems;

other uncertainties arising out of foreign government sovereignty over its international operations; and

currency restrictions and exchange rate fluctuations.

Tensions between China and its neighbors or various western countries, regional political or military disruption, changes in internal Chinese leadership, social or political disruptions within China, a downturn in the Chinese economy, or a change in Chinese laws or attitudes toward foreign investment could make China an unfavorable environment in which to invest. Although all the foreign interest owners in the Bohai Bay properties have the right to sell production in the world market, the regulation of the concession by China, and the likely participation by CNOOC as a large working interest owner, make Chinese internal and external affairs important to the investment in the Bohai Bay property. If any of these negative events were to occur, it could lead to a decision that there is an intolerable level of risk in continuing with the investment, or the Company may be unable to attract equity investors or lenders, or satisfy any then existing lenders.

In the event of a dispute arising from foreign operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of courts in the United States or a potentially more favorable country.

In addition, the Company s China PSC terminates after 15 years of production, unless extended as provided for, which may be prior to the end of the productive life of the fields.

Our operations in China have special operational risks that may negatively affect the value of those assets.

Offshore operations, such as the Company s Bohai Bay properties, are subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and/or loss from storms or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, the Company could incur substantial liabilities that could result in financial losses or failures. China has many regulations similar to those addressed in Item 1, Environmental Regulation, that may expose the Company to liability. Offshore projects, like the China field developments, are typically large, complex construction projects that are potentially subject to delays which may cause delays in achieving production and profitability.

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 such expressions are forward-looking statements. The Company can give no assurances that the assumptions upon which such forward-looking statements are based will prove to be correct.

Forward-looking statements include statements regarding:

our oil and 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 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 is dependent on oil and gas leases in Wyoming and two petroleum contracts in China in order to explore for and produce oil and gas. The leases in Wyoming are primarily federal leases with 10-year lease terms until establishment of production. Production on the lease extends the lease terms until cessation of that production. There are approximately 93,865 gross (42,298 net) acres currently held by production in Wyoming. The China petroleum contracts are for a maximum of 30 years and are divided into 3 periods; exploration, development and production. The exploration period is for approximately 7 years and work is to be performed and expenditures are to be incurred to delineate the extent and amount of hydrocarbons, if any, for each block. The development period occurs when a field is discovered and commences on the date of approval of the Ministry of Energy. There is no limit on the time allowed to develop a field other than the combined maximum of 30 years. The production period of any oil and gas field in a block is a period of 15 consecutive years beginning on the date of commencement of commercial production from the field, unless extended.

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Green River Basin, Wyoming

As of December 31, 2005, the Company owned developed oil and gas leases totaling 12,552 gross (5,284 net) acres in the Green River Basin of Sublette County, Wyoming which represents 99.7% of the Company s total domestic developed net acreage. The Company owns undeveloped oil and gas leases totaling 135,455 gross (73,404 net) acres in the Green River Basin of Sublette County, Wyoming which represents 74.9% of the Company s total domestic undeveloped net acreage. The Company s acreage in the Green River Basin primarily covers the Pinedale Anticline with several other undeveloped acreage blocks north and west of the Pinedale Anticline as well as acreage in the Jonah Field. Holding costs of leases in Wyoming not held by production were approximately $122,530 for the fiscal year ended December 31, 2005. The primary target on the Company s Wyoming acreage is the tight gas sands of the upper Cretaceous Lance Pool formation.

Exploratory Wells. During the year-ended December 31, 2005, the Company participated in the drilling and completion of a total of 18 gross (8.62 net) productive exploratory wells on the Green River Basin properties. At December 31, 2005, there were 11 gross (4.28 net) additional exploratory wells that commenced during the year that were either still drilling, had drilling operations suspended or are in various stages of completion.

Development Wells. During the year-ended December 31, 2005, the Company participated in the drilling and completion of 60 gross (23.68 net) productive development wells in the Pinedale Field area. At December 31, 2005, there were 19 gross (6.28 net) additional development wells that commenced during 2005 that were either still drilling, had drilling operations suspended or are in various stages of completion. Additionally, 2 gross (1.28 net) wells in Jonah field had drilling operations commenced during 2005 that were either still drilling, had drilling operations suspended or are in various stages of completion. 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.

Bohai Bay, China

Block 04/36: The Petroleum Sharing Contract (PSC) covering this block became effective October 1, 1994. Negotiations with the Chinese government in 2005 resulted in an extension of the third exploration term to September 2007. As the PSC now stands, the exploration period will end at the end of September 2007. Barring another extension, at that time, all acreage not under appraisal, development or production must be relinquished. The Company holds an 18.18% exploration interest in the exploration portion of the block and an 8.91% working interest in the CFD 11-1 and 11-2 and the CFD 11-3 and 11-5 producing oil fields. This block covers 413,623 gross (75,197 net) acres under the exploration phase and 40,377 gross (3,598 net) acres under development, or approximately 66% of the Company s total gross international acreage.

Block 05/36: The PSC covering this block became effective March 1, 1996. Negotiations with CNOOC at the end of 2005 resulted in a two year extension of the third exploration term to February 28, 2008 when, barring an extension, all acreage not under appraisal, development or production must be relinquished. The extension granted by CNOOC must be ratified by the Chinese Government which we anticipate will happen during 2006. The Company holds a 23.08% exploration interest in this block which covers 218,079 gross (50,376 net) acres under the exploration phase and 15,221 gross (1,119 net) acres under development. This acreage constitutes approximately 34% of the Company s total gross international acreage.

Exploration/ Appraisal Activity: In 2005, the Company participated in drilling 1 exploration well (0.18 net) which failed to find commercial quantities of oil. The primary target formations on the Blocks are the Upper and Lower Minghuazhen, Guantao and Dongying formations.

Development Activity: In July 2004, the Company started production at the CFD 11-1 and 11-2 fields on the 04/36 Block. Production well drilling at these fields continued through 2005 and will continue into the first half of 2006. The Company has participated in drilling a total of 47 production wells at the CFD 11-1 and CFD 11-2 fields. In July 2005, the Company commenced production at the CFD 11-3 and 11-5 fields on the

04/36 Block. The Company has participated in drilling a total of 6 production wells at the CFD 11-3 and CFD 11-5 fields. The four field production complex currently consists of 53 producing wells, three production platforms and an anchored FPSO vessel.

Upon declaration of commerciality of a field or area by CNOOC, the Company s share of all expenses within that area is decreased by 51%, with the participation by CNOOC. For example, the Company s 18.18% exploration interest is reduced to an 8.91% working interest in the fields on production in the 04/36 Block. Upon initiation of production, the sharing of production is determined by the language of the PSC which states that for each individual field: 1) a Chinese National Industrial Tax and Royalty are applied to 100% of the gross volumes of oil, 2) Lease Operating Expenses (LOE) are then taken out of the remainder oil and 3) after these deductions, 62.5% of the remaining production stream is dedicated to Exploration and Development Cost Recovery for the participants. The Exploration Cost Recovery shall be recovered without interest, while the Development Cost Recovery shall be calculated with a fixed annual interest rate of 9% uplift, and 4) the remaining 37.5% of production goes to the remainder oil category which is divided into a share oil for CNOOC and an allocable remainder oil for the contractors determined by a sliding scale (determined by yearly production), X factor. Project profit is subject to Chinese corporate tax.

There are three new fields, the CFD 11-6, CFD 12-1 and CFD 12-1S that are currently being developed. The CFD 11-6 field area is on the 04/36 Block. The CFD 12-1 and CFD 12-1S field areas are on the 05/36 Block. These development areas are located in close proximity and thus will be developed as a single unit within the Blocks. The development areas have been unitized because the fields are within both the 04/36 and 05/36 Blocks where different parties have different levels of interest. The unit allows for an equitable distribution of production known to exist within the known areas of the fields to the various parties. On May 27, 2005, a Unitization Agreement was signed that assigned the Company a 7.82% working interest in the combined field unit.

On October 16, 2003, a 15 year contract which provides for extension for up to an additional 10 years, was signed by the operator to lease the FPSO. The Company ratified the contract for its net share. The FPSO is a 110,000 150,000 dead weight tons, double-hull FPSO with a 900,000 1,100,000 barrels storage capacity, with single point mooring and a processing plant capable of processing 60,000 barrels oil per day (expandable to 80,000 barrels oil per day). The FPSO service agreement calls for a day rate lease payment and a sliding scale per barrel payment that decreases based on cumulative barrels processed.

Pennsylvania

The Company owns 26,868 gross (24,610 net) acres in Pennsylvania, which represents 25.1% of the Company s total domestic undeveloped net acreage. Holding costs of leases in Pennsylvania not held by production were approximately $247,000 for the fiscal year ended December 31, 2005.

Exploratory Wells. During the year ended December 31, 2005, the Company participated in the drilling and completion of a total of 1 gross (1.0 net) successful exploratory well on the Pennsylvania properties. Based on the test results, Ultra is preparing to lay a pipeline to connect this well to sales. It is anticipated that this connection should be completed during the first half of 2006.

Texas

During the year ended, December 31, 2005, the Company divested itself of a portion of its Texas properties. The Company sold one gross (0.66 net) operated well along with the associated 640 gross (369 net) acres. The Company is currently attempting to divest itself of its remaining interest in Texas which consist of 1 gross (0.12 net) non-operated producing well, plus the associated 80 gross (14.0 net) acres. This represents 0.3% of the Company s total developed net acreage.

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Oil and Gas Reserves

The following table sets forth the Company s quantities of domestic proved reserves, for the years-ended December 31, 2005, 2004 and 2003 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, 2005, 2004 and 2003. 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, 2009. Proved undeveloped reserves represent 66.6% of total proved reserves.

	December 31,		
	2005	2004	2003
	(In thousands)		
Proved Undeveloped Reserves			
Natural gas (MMcf)	1,264,632	899,315	664,295
Oil (MBbl)	10,117	7,195	5,314
Proved Developed Reserves			
Natural gas (MMcf)	635,591	514,686	359,072
Oil (MBbl)	5,087	4,195	3,028
Total Proved Reserves (MMcfe)	1,991,447	1,482,341	1,073,419
Estimated future net cash flows, before income tax	$ 12,067,267	$ 5,889,630	$ 4,456,478
Standardized measure of discounted future net cash flows, before income taxes(1)	$ 5,311,312	$ 2,438,837	$ 1,784,314
Future income tax	$ 1,809,228	$ 823,372	$ 648,801
Standardized measure of discounted future net cash flows, after income tax	$ 3,502,084	$ 1,615,465	$ 1,135,513

(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 year-ending December 31, 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 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, 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, 2009. Proved undeveloped reserves represent 50.9% of total proved reserves.

	December 31,		
	2005	**2004**	**2003**
	(In thousands)		
Proved Undeveloped Reserves			
Natural gas (MMcf)			
Oil (MBbl)	2,577	3,231	
Proved Developed Reserves			
Natural gas (MMcf)			
Oil (MBbl)	2,484	4,356	
Total Proved Reserves (MMcfe)	30,366	45,526	
Estimated future net cash flows, before income tax	$ 166,931	$ 137,762	$
Standardized measure of discounted future net cash flows, before income taxes(1)	$ 134,271	$ 103,518	$
Future Income Tax	59,861	49,647	
Standardized measure of discounted future net cash flows, after income tax	$ 74,410	$ 53,871	$

(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.

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The following table sets forth the Company s quantities of total proved reserves both domestically and in China, for the years-ended December 31, 2005, 2004 and 2003 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, 2005, 2004 and 2003. 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, 2009. Proved undeveloped reserves represent 66.3% of total proved reserves.

	December 31,		
	2005	2004	2003
	(In thousands)		
Proved Undeveloped Reserves			
Natural gas (MMcf)	1,264,632	899,315	664,295
Oil (MBbl)	12,694	10,426	5,314
Proved Developed Reserves			
Natural gas (MMcf)	635,591	514,686	359,072
Oil (MBbl)	7,571	8,551	3,028
Total Proved Reserves (MMcfe)	2,021,813	1,527,867	1,073,419
Estimated future net cash flows, before income tax	$ 12,234,198	$ 6,027,392	$ 4,456,478
Standardized measure of discounted future net cash flows, before income taxes(1)	$ 5,445,583	$ 2,542,355	$ 1,784,314
Future income tax	$ 1,869,089	$ 873,019	$ 648,801
Standardized measure of discounted future net cash flows, after income tax	$ 3,576,494	$ 1,669,336	$ 1,135,513

(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.

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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,		
	2005	2004	2003
Production			
Natural gas (Mcf)	61,722,349	43,667,384	27,621,759
Oil (Bbl) US	464,330	349,673	211,591
Oil (Bbl) China	1,556,280	624,560	
Total (Mcfe)	73,846,009	49,512,782	28,891,305
Revenues			
Natural Gas sales	$ 422,091,034	$ 224,207,694	$ 114,840,558
Oil sales US	26,639,931	14,659,219	6,740,539
Oil sales China	67,762,036	20,179,534	
Total Revenues	516,493,001	259,046,447	121,581,097
Lease Operating Expenses			
Production costs US*	9,047,390	6,286,715	3,627,639
Production costs China*	7,352,000	2,286,000	
Severance/production taxes WY	52,689,060	28,151,661	13,767,668
Severance/production taxes China	3,388,089	1,009,098	
Gathering	17,125,147	13,135,809	7,828,372
Total Lease Operating Expenses	$ 89,601,686	$ 50,869,283	$ 25,223,679
Realized Prices			
Natural gas ($/Mcf)	$ 6.84	$ 5.13	$ 4.16
Oil ($/Bbl) US	$ 57.37	$ 41.92	$ 31.86
Oil ($/Bbl) China	$ 43.54	$ 32.31	$
Operating Costs per Mcfe			
Production costs Total	$ 0.22	$ 0.17	$ 0.13
Severance/production taxes	$ 0.76	$ 0.59	$ 0.48
Gathering	$ 0.23	$ 0.27	$ 0.27
DD&A	$ 0.79	$ 0.61	$ 0.56
Interest	$ 0.04	$ 0.08	$ 0.10
Total Operating Costs per Mcfe	$ 2.04	$ 1.72	$ 1.54

* Average production costs include lifting costs and remedial workover expenses.

Productive Wells

As of December 31, 2005, the Company s total gross and net wells were as follows:

Productive Wells*	Gross Wells	Net Wells
Domestic		
Natural Gas and Condensate	332.00	140.84
China		
China Oil	53.00	4.73
TOTAL	385.00	145.57

* 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, 2005, the Company had total gross and net developed and undeveloped oil and gas leasehold acres in the United States as set forth below. 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 gas operations are presented in the following tables.

United States Acreage:

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Wyoming	12,552	5,284	135,455	73,404
Pennsylvania			26,868	24,610
Texas	80	14		
All States	12,632	5,298	162,323	98,014

As of December 31, 2005, the Company had total gross and net developed and undeveloped oil and gas leasehold acres in the Bohai Bay, China as set forth below.

Bohai Bay Acreage:

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Block 04/36	40,377	3,598	413,623	75,197
Block 05/36	15,221	1,119	218,079	50,376
Total Bohai Acreage	55,598	4,717	631,702	125,573

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Drilling Activities

For each of the three fiscal years ended December 31, 2005, 2004 and 2003, the number of gross and net wells drilled by the Company was as follows:

Wyoming Green River Basin

	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	60.00	23.68	34.00	14.48	24.00	6.88
Dry	0.00	0.00	0.00	0.00	0.00	0.00
Total	60.00	23.68	34.00	14.48	24.00	6.88

At year end there were 21 gross (7.56 net) additional development wells that were either drilling, had drilling operations suspended or were in various stages of completion. This includes wells in both the Pinedale and Jonah fields.

	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	18.00	8.62	32.00	14.00	24.00	9.86
Dry	0.00	0.00	0.00	0.00	1.00	0.32
Total	18.00	8.62	32.00	14.00	25.00	10.18

At year end there were 11 gross (4.28 net) additional exploratory wells that were either drilling, had drilling operations suspended or were in various stages of completion.

Pennsylvania

	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	1.00	1.00	0.00	0.00	0.00	0.00
Dry	0.00	0.00	0.00	0.00	0.00	0.00
Total	1.00	1.00	0.00	0.00	0.00	0.00

Texas

	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net

Exploratory Wells						
Productive	0.00	0.00	0.00	0.00	0.00	0.00
Dry	0.00	0.00	1.00	0.73	0.00	0.00
Total	0.00	0.00	1.00	0.73	0.00	0.00

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China Bohai Bay

	2005		2004		2003	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development Wells						
Productive	17.00	1.52	36.00	3.21	0.00	0.00
Dry	0.00	0.00	0.00	0.00	0.00	0.00
Total	17.00	1.52	36.00	3.21	0.00	0.00
Exploratory Wells						
Productive and Successful Appraisal*	0.00	0.00	0.00	0.00	6.00	1.03
Dry	1.00	0.18	1.00	0.18	4.00	0.66
Total	1.00	0.18	1.00	0.18	10.00	1.69

* A successful appraisal well is a well that is drilled into a formation shown to be productive of oil or 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, 2005.

PART II

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

The common shares of the Company have been listed and posted for trading on the American Stock Exchange (AMEX) since January 17, 2001 under the symbol UPL and were traded on the Toronto Stock Exchange (TSX) from September 30, 1998 to March 31, 2004 under the symbol UP . The following table sets forth the high and low intra-day sales prices on the AMEX and TSX for 2005 and 2004 as reported by each exchange, respectively. The prices are adjusted for a 2 for 1 stock split effective May 10, 2005.

AMERICAN STOCK EXCHANGE (US$)

2005	**High**	**Low**
First Quarter	$ 29.17	$ 22.20
Second Quarter	$ 30.50	$ 21.48
Third Quarter	$ 57.89	$ 30.36
Fourth Quarter	$ 60.32	$ 45.10

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AMERICAN STOCK EXCHANGE (US$)

2004	High	Low
First Quarter	$ 15.65	$ 10.25
Second Quarter	$ 19.00	$ 13.80
Third Quarter	$ 25.50	$ 17.53
Fourth Quarter	$ 27.83	$ 21.69

TORONTO STOCK EXCHANGE (CDN$)

2004	High	Low
First Quarter	$ 20.13	$ 14.83
Second Quarter	$	$
Third Quarter	$	$
Fourth Quarter	$	$

On February 28, 2006 the last reported sales price of the common stock on the AMEX was $52.04 per share. As of February 28, 2006 there were approximately 456 holders of record of the common stock.

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. In addition, the Company s current credit facility limits payment of dividends on its common stock.

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Item 6. *Selected Financial Data.*

The selected consolidated financial information presented below for the years ended December 31, 2005, 2004, 2003, 2002 and 2001 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,				
	2005	2004	2003	2002	2001
	(In thousands, except per share data)				
Statement of Operations Data					
Revenues:					
Natural gas sales	$ 422,091	$ 224,208	$ 114,841	$ 38,503	$ 38,204
Oil sales	94,402	34,839	6,740	3,839	2,997
Interest and other	612	91	37	23	393
Total revenues	$ 517,105	$ 259,138	$ 121,618	$ 42,365	$ 41,594
Expenses:					
Production expenses and taxes	89,602	50,869	25,224	11,411	9,023
Depreciation, depletion and amortization	58,103	30,249	16,216	9,712	6,687
General and administrative	11,484	6,152	5,733	4,199	3,894
Stock compensation	2,859	924	1,018	1,211	337
Interest	3,286	3,783	2,851	2,691	1,687
Total expenses	165,333	91,977	51,042	29,224	21,628
Income before income taxes	351,772	167,160	70,576	13,141	19,966
Income tax provision deferred	123,472	58,010	25,254	5,059	2,087
Net income	$ 228,300	$ 109,150	$ 45,323	$ 8,082	$ 17,879
Basic income per common share	$ 1.49	$ 0.73	$ 0.31	$ 0.05	$ 0.13
Diluted income per common share	$ 1.41	$ 0.68	$ 0.29	$ 0.05	$ 0.12
Statement of Cash Flows Data					
Net cash provided by (used in):					
Operating activities	$ 414,353	$ 175,343	$ 90,051	$ 21,490	$ 34,136
Investing activities	(306,547)	(165,014)	(103,622)	(64,360)	(59,862)
Financing activities	(80,344)	4,770	13,988	42,908	25,961
Balance Sheet Data					
Cash and cash equivalents	$ 44,395	$ 16,933	$ 1,834	$ 1,418	$ 1,379
Working capital (deficit)	42,713	(9,969)	(22,057)	(4,415)	(6,635)
Oil and gas properties	702,663	474,634	307,864	207,362	155,221
Total assets	847,266	537,186	345,770	221,874	167,583
Total long-term debt		102,000	99,000	86,000	43,000
Other long-term obligations	20,577	9,735	5,120	3,859	3,193
Deferred income taxes, net	155,746	85,035	33,446	10,033	4,974

Total shareholders equity	571,201	267,992	149,453	104,067	95,320

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

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

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 2001-2005 have ranged from $2.33 to $8.64 per Mcf. This volatility could be very 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 2005 was $6.84 per Mcf, basis Opal, Wyoming, including the effect of hedges. For the quarter ended December 31, 2005, the average realization for the Company s natural gas was $8.49 per Mcf, basis Opal, Wyoming, including the effect of hedges.

On July 18, 2004 the Company initiated production at the first two fields of the nine fields discovered on its oil properties offshore Bohai Bay, China. Production from these fields is characterized as a heavy, sweet crude. The Company sold its first cargos of oil in September 2004. During the twelve-month period ended December 31, 2005, the Company sold 1,556,280 barrels of its Chinese oil production at a price based on the official ICP posting for Duri field crude, less a discount for location and quality differences. These sales were made to an affiliate of CNOOC at an average price of $43.54 USD per barrel for the year ended December 31, 2005. For the quarter ended December 31, 2005, the Company sold 393,084 barrels of its Chinese crude for an average price of $48.16 USD per barrel. There can and will be differences in timing between the sale of the Company s crude oil cargos and the Company s pro-rata share of production. As a result of these timing differences, the Company may, from time to time, carry inventories or imbalances of crude oil. As of February 28, 2006, the Duri price was approximately $54.56 USD (before discount) per barrel.

The Company expects to sell at least one cargo of its Chinese crude oil production approximately every two months during 2006. The Company has the right to export and sell its crude at market prices into the international markets, and is evaluating options to do so in the future. Other markets for the Company s Chinese oil may potentially be developed in South Korea, Japan, Singapore or other countries.

The Company has grown its natural gas and oil production significantly over the past five years and management believes it has the ability to continue growing production by drilling already identified locations on its leases in Wyoming and by bringing into production the already discovered oil fields in China. The Company delivered 25% production growth on an Mcfe basis during the quarter ended December 31, 2005 as compared to the same quarter in 2004 and 49% production growth for the year-ended December 31, 2005 compared to the same period in 2004. Management expects to deliver additional production growth during 2006 by drilling and bringing into production additional wells in Wyoming and bringing into production additional fields in China.

	2002	2003	2004	2005
Production Bcfe	17.4	28.9	49.5	73.8

The Company conducts operations in both the United States and China. Separate cost centers are maintained for each country in which the Company has operations. Substantially all of the oil and 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.

Use of Estimates. The more significant areas requiring the use of assumptions, judgments and estimates relate to volumes of oil and gas reserves used in calculating depletion, the amount of future net revenues 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 Company emphasizes that the volumes of reserves are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data as well as production performance data. These estimates are currently made annually by independent petroleum engineers and reviewed by the Company s engineers. The reserves are periodically reviewed and revised, either upward or downward, if warranted based upon additional data. Revisions are necessary due to changes in assumptions based on, among other things, reservoir performance, prices, economic conditions and governmental restrictions. Estimates of proved crude oil and natural gas reserves significantly affect the Company s depreciation, depletion and amortization (DD&A) expense. For example, if estimates of proved reserves decline, the Company s DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves could also result in a full cost ceiling write-down (see discussion below).

The present value of oil and gas properties represents the estimated future net cash flows from proved oil and gas reserves, discounted using a prescribed 10% discount rate (PV 10). Proved oil and gas 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. Reserves are considered proved if they can be produced economically as demonstrated by either actual production or conclusive formation tests. Proved developed oil and gas reserves can be expected to be recovered through existing wells with existing equipment and operating methods.

Due to the volatility of commodity prices, the oil and gas prices on the last day of the period significantly impact the calculation of the PV 10. The present value of future net cash flows does not purport to be an estimate of the fair market value of the Company s proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money and the risks inherent in producing oil and gas.

Full Cost Method of Accounting. The Company uses the full cost method of accounting for its oil and gas operations. 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. Effective with the adoption of Statement of Financial Accounting Standard (SFAS) No. 143, Accounting for Asset Retirement Obligations, the carrying amount of oil and gas properties includes estimated asset retirement costs recorded based on the fair value of the asset retirement obligation when incurred. The sum of net capitalized costs and estimated future development costs of oil and gas properties for each full cost center are depleted using the units-of-production method. Changes in estimates of 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 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. 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 Company did not have any write-downs related to the full cost ceiling limitation in 2005, 2004 or 2003. As of December 31, 2005, the ceiling limitation exceeded the carrying value of the Company s oil and gas properties. Estimates of discounted future net cash flows at December 31, 2005 were based on average natural gas prices of approximately $8.00 per MCF in the U.S. and on average liquids prices of approximately $60.81 per barrel in the U.S. In China, estimates of discounted future net cash flows on crude oil were based on a net realized price of $48.74 per barrel. A reduction in oil and gas prices and/or estimated quantities of oil and 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 gas properties. 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 gas asset. The recognition of an ARO requires that management make numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO, estimated probabilities, amounts and timing of settlements; the credit-adjusted, risk-free rate to be used; inflation rates, and future advances in technology. In periods subsequent to initial measurement of the ARO, the Company must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A.

Entitlements Method of Accounting for Oil and Gas Sales. The Company generally sells natural gas, condensate and crude oil under both long-term and short-term agreements at prevailing market prices. The Company recognizes revenues when the products are 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 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. Under the alternative sales method of accounting for oil and gas sales, revenue would be recorded based on volumes taken by the Company or allocated to it by third parties, regardless of whether such volumes are more or less than its ownership share of volumes produced. Reserve estimates would be adjusted to reflect any over- produced or under-produced positions. Receivables or payables would be recognized on a company s balance sheet only to the extent that remaining reserves are not sufficient to satisfy volumes over- or under-produced.

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 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, 2004, the Company had U.S. federal regular tax net operating loss carryforwards (NOL s) of approximately $16.7 million which were fully utilized to offset U.S. taxable income in 2005.

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 counter-parties 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. On a less frequent basis, the Company may 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 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 not have any derivative contracts related to the marketing of its natural gas or oil production in effect, the last one having expired on December 31, 2005.

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. In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123R, Share-Based Payments (SFAS No. 123R). SFAS No. 123R is a revision of SFAS No. 123, Accounting for Stock Based Compensation , and supersedes APB Opinion No. 25 (APB Opinion 25). Among other items, SFAS No. 123R eliminates the use of APB Opinion 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. The

Company will adopt SFAS No. 123R as of the required effective date for calendar year companies, which is January 1, 2006.

SFAS No. 123R permits companies to adopt its requirements using either a modified prospective method, or a modified retrospective method. Under the modified prospective method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS No. 123R for all share-based payments granted after that date, and based on the requirements of SFAS No. 123 for all unvested awards granted prior to the effective date of SFAS No. 123R. Under the modified retrospective method, the requirements are the same as under the modified prospective method, but also permit entities to restate financial statements of previous periods based on proforma disclosures made in accordance with SFAS No. 123. At December 31, 2005, all stock options granted to date were fully vested.

The Company currently utilizes a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to Employees. While SFAS No. 123R permits entities to continue to use such a model, the standard also permits the use of a more complex binomial, or lattice model. Based upon research done by the Company on the alternative models available to value option grants, and in conjunction with the type and number of stock options expected to be issued in the future, the Company has determined that it will continue to use the Black-Scholes model for option valuation as of the current time.

SFAS No. 123R includes several modifications to the way that income taxes are recorded in the financial statements. The expense for certain types of option grants is only deductible for tax purposes at the time that the taxable event takes place, which could cause variability in the Company s effective tax rates recorded throughout the year. SFAS No. 123R does not allow companies to predict when these taxable events will take place. Furthermore, it requires that the benefits associated with the tax deductions in excess of recognized compensation cost be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement will reduce net operating cash flows and increase net financing cash flows in periods after the effective date. These future amounts cannot be estimated, because they depend on, among other things, when employees exercise stock options.

Results of Operations Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Oil and gas revenues increased to $516.5 million for the year ended December 31, 2005 from $259.0 million for the same period in 2004. This increase was attributable to an increase in both the Company s production volumes and prices received for that production coupled with a full year s production from the China asset. During 2005, the Company s production increased to 61.7 Bcf of natural gas and 464.3 thousand barrels of condensate in Wyoming and 1.6 million barrels of crude oil in China, up from 2004 levels of 43.7 Bcf of natural gas and 349.7 thousand barrels of condensate in Wyoming and 624.6 thousand barrels of crude oil in China . This 49% increase on an Mcfe basis was attributable to the Company s successful drilling activities during 2005 and 2004 in Wyoming and initiation of production in China during July 2004. During the year ended December 31, 2005, the average product prices received were $6.84 per Mcf and $57.37 per barrel of condensate in Wyoming and $43.54 per barrel for crude oil in China, compared to $5.13 per Mcf and $41.92 per barrel of condensate in Wyoming and $32.31 per barrel of crude oil in China for the same period in 2004.

In Wyoming, direct lease operating costs increased to $9.0 million in 2005 from $6.3 million in 2004 due largely to higher production volumes. On a unit of production basis, LOE costs were flat at $0.14 per Mcfe in 2005 when compared to 2004. Production taxes in Wyoming during the year ended December 31, 2005 were $52.7 million compared to $28.2 million in 2004, or $0.82 per Mcfe in 2005, compared to $0.62 per Mcfe in 2004. Production taxes in Wyoming are calculated based on a percentage of revenue from production. Therefore, higher prices received increased production taxes on a per unit basis. Gathering fees in Wyoming for the year ended December 31, 2005 increased to $17.1 million, or $0.27 per Mcfe in 2005 from $13.1 million, or $0.29 per Mcfe, in 2004 as a result of higher production volumes.

In Wyoming, DD&A expenses increased to $48.5 million during the year ended December 31, 2005 from $27.3 million for the same period in 2004, attributable to increased production volumes and a higher depletion

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rate due to forecasted increased future development costs. On a unit basis, DD&A expense in Wyoming increased to $0.75 per Mcfe in 2005 from $0.60 per Mcfe in 2004.

In China, production costs were $7.4 million in 2005, or $0.79 per Mcfe or $4.72 per BOE, compared with $2.3 million in 2004, or $0.61 per Mcfe or $3.66 per BOE. Severance taxes in China during the year ended December 31, 2005 were $3.4 million compared to $1.0 million in 2004, or $0.36 per Mcfe ($2.18 per BOE) in 2005 compared to $0.27 per Mcfe ($1.62 per BOE) in 2004. The increase in severance taxes relates to a full year of production during 2005 compared to half year in 2004. In China, DD&A expense was $9.6 million or $1.03 per Mcfe or $6.20 per BOE, in 2005 compared to $2.9 million, or $0.77 per Mcfe or $4.65 per BOE in 2004. Production commenced in China during July 2004.

Interest expense decreased to $3.3 million in 2005 from $3.8 million in 2004. This decrease was largely attributable to the decrease in borrowings under the senior credit facility and was partially offset by increased interest rates during 2005.

Deferred income tax expense increased to $123.5 million in 2005 from $58.0 million in 2004. This increase was primarily attributable to an increase in net income from continuing operations combined with an increase in the tax rate. Deferred income taxes were booked at the rate of 35.1% for the year ended December 31, 2005 as compared to a rate of 34.7% in 2004. The Company was not liable for current payment of any material amount of income taxes for the period ending December 31, 2005.

Results of Operations Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

Oil and gas revenues increased to $259.0 million for the year ended December 31, 2004 from $121.6 million for the same period in 2003. This increase was attributable to an increase in both the Company s production and prices received for that production as well as the production from the China assets beginning in July 2004. During this period the Company s production increased to 43.7 Bcf of natural gas and 349.7 thousand barrels of condensate in Wyoming and 624.6 thousand barrels of crude oil in China, up from 27.6 Bcf of natural gas and 211.6 thousand barrels of condensate for the same period in 2003. This 71% increase on an Mcfe basis was attributable to the Company s successful drilling activities during 2004 and 2003. During the year ended December 31, 2004 the average product prices were $5.13 per Mcf and $41.92 per barrel of condensate in Wyoming and $32.31 per barrel for crude oil in China, compared to $4.16 per Mcf and $31.86 per barrel of condensate in Wyoming for the same period in 2003. The China production began in July 2004.

In Wyoming, direct lease operating costs increased to $6.3 million in 2004 from $3.6 million in 2003 due to higher production. On a unit of production basis, LOE costs were $0.14 per Mcfe in 2004, as compared to $0.13 per Mcfe in 2003. Production taxes in Wyoming during 2004 were $28.2 million, compared to $13.8 million in 2003, or $0.62 per Mcfe in 2004, compared to $0.48 per Mcfe in 2003. Production taxes are calculated based on a percentage of revenue from production. Therefore, higher prices received increased the cost on a per unit basis. Gathering fees in Wyoming increased to $13.1 million in 2004 from $7.8 million in 2003, attributable to higher production volumes.

In Wyoming, DD&A expenses increased to $27.3 million during the year ended December 31, 2004 from $16.2 million for the same period in 2003, attributable to increased production volumes and a higher depletion rate, attributable to forecasted increased future development costs. On a unit basis, DD&A increased to $0.60 per Mcfe in 2004 from $0.56 per Mcfe in 2003.

In China, production costs were $2.3 million in 2004, or $0.61 per Mcfe or $3.66 per BOE. Severance taxes in China during the year ended December 31, 2004 were $1.0 million, or $0.27 per Mcfe ($1.62 per BOE). DD&A was $2.9 million or $0.77 per Mcfe or $4.65 per BOE in 2004.. Production in China started during July 2004.

Interest expense increased to $3.8 million during 2004 from $2.8 million in 2003. This increase was attributable to the increase in borrowings under the senior credit facility combined with increasing interest rates.

Deferred income tax expense for the period increased to $58.0 million in 2004 from $25.3 million in 2003. This increase was attributable to an increase in net income from continuing operations. Deferred income taxes were booked at the rate of 34.7% as compared to a rate of 35.8% in 2003. The Company was not liable for current payment of any material amount of income taxes for the period ending December 31, 2004.

Liquidity and Capital Resources

During the year-ended December 31, 2005, the Company relied on cash provided by operations and borrowings under its senior credit facility to finance its capital expenditures. The Company participated in the drilling of 110 wells in Wyoming and continued to participate in the development process in the China blocks, including the ongoing drilling of development wells. For the year-ended December 31, 2005 net capital expenditures were $282.7 million. At December 31, 2005, the Company reported a cash position of $44.4 million compared to $16.9 million at December 31, 2004. Working capital at December 31, 2005 was $42.7 million as compared to $(10.0) million at December 31, 2004. As of December 31, 2005, the Company had no outstanding bank indebtedness and other long-term obligations of $20.6 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 2006, which are currently projected to be $425.0 million. Of the $425.0 million budget, the Company plans to spend approximately $400.0 million in Wyoming and approximately $20.0 million in China with the balance allocated to evaluating other areas. With the $400.0 million budgeted for Wyoming, the Company plans to drill or participate in an estimated 160 gross wells in 2006, of which approximately 25% will be for exploration wells and the remaining will be for development wells. Of the $20.0 million budgeted for China, approximately 33% will be for exploratory/appraisal activity and the balance will be for development activity. The Company currently has no budget for acquisitions in 2006.

The Company (through its subsidiary) participates in a revolving credit facility with a group of banks led by JP Morgan Chase Bank, N.A. The agreement specifies a maximum loan amount of $500 million, an aggregate borrowing base of $800 million and a commitment amount of $200 million at November 14, 2005. The commitment amount may be increased up to the lesser of the borrowing base amount or $500 million at any time at the request of the Company. Each bank shall have the right, but not the obligation, to increase the amount of their commitment as requested by the Company. In the event that the existing banks increase their commitment to an amount less than the requested commitment amount, then it would be necessary to bring additional banks into the facility. At December 31, 2005, the Company had no amounts outstanding and $200 million unused and available under the current committed amount.

The credit facility matures on May 1, 2010. The note bears interest at either (A) the bank s prime rate plus a margin of zero percent (0.00%) to three-quarters of one percent (0.75%) based on the percentage of available credit drawn or at (B) LIBOR plus a margin of one percent (1.00%) to one and three-quarters of one percent (1.75%) based on the percentage of available credit drawn. For purposes of calculating interest, the available credit is equal to the borrowing base. An average annual commitment fee of 0.25% to 0.375%, depending on the percentage of available credit drawn, is charged quarterly for any unused portion of the commitment amount. The Company s total commitment fees were $354,017, $374,096 and $249,788 for the years ended December 31, 2005, 2004 and 2003, respectively.

The borrowing base is subject to periodic (at least semi-annual) review and re-determination by the banks and may be decreased or increased depending on a number of factors, including the Company s proved reserves and the bank s forecast of future oil and gas prices. If the borrowing base is reduced to an amount less than the balance outstanding, the Company has sixty days from the date of written notice of the reduction in the borrowing base to pay the difference. Additionally, the Company is subject to quarterly reviews of compliance with the covenants under the bank facility including minimum coverage ratios relating to interest, working capital and advances to Sino-American Energy Corporation. In the event of a default under the covenants, the Company may not be able to access funds otherwise available under the facility. As of December 31, 2005, the Company was in compliance with required ratios of the bank facility.

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The debt outstanding under the credit facility is secured by a majority of the Company s proved domestic oil and gas properties.

During the year ended December 31, 2005, net cash provided by operating activities was $414.4 million as compared to $175.3 million for the year ended December 31, 2004. The increase in cash provided by operating activities was primarily due to the increase in earnings which was due to higher production levels and higher prices received for that production.

During the year ended December 31, 2005, cash used in investing activities was $306.5 million as compared to $165.0 million for the year ended December 31, 2004. The change is primarily attributable to increased activity for drilling and completion operations in Wyoming. The $288.9 million used in oil and gas property expenditures consists of $282.7 million incurred for drilling and completion activities in 2005, and $6.2 million attributable to the timing of capital expenditures incurred but not yet paid.

During the year ended December 31, 2005, cash used in financing activities was $80.3 million as compared to cash provided by financing activities of $4.8 million for the year ended December 31, 2004. The change is primarily attributable to debt repayment under the senior credit facility offset by proceeds from employee stock option exercises.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2005:

	Payments Due by Period:				
	Total	Less Than One Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$	$	$	$	$
Drilling contracts	108,410,500		104,610,500	3,800,000	
Operating leases	132,020	132,020			
Office space lease	813,583	367,329	446,254		
Total contractual obligations	$ 109,356,103	$ 499,349	$ 105,056,754	$ 3,800,000	$

As of December 31, 2005, the Company had committed to drilling obligations with certain rig contractors that will continue into 2009. The mentioned drilling rigs were contracted to fulfill the 2006-2008 drilling program initiatives in Wyoming.

On October 16, 2003 the operator of the Company s properties in China, Kerr-McGee, signed a 15 year contract, which provides for up to an additional 10 years, to lease the FPSO. The Company ratified the contract for its net share which is 8.91%. The FPSO service agreement calls for a day rate lease payment and a sliding scale per barrel processing fee that decreases based on cumulative barrels processed. The lease contains a cancellation fee for the Company based on a sliding time-scale (cancellation fee decreases with time) which as of December 31, 2005 was $3.3 million net to the Company s 8.91% interest. The Company considers it very unlikely that a lease cancellation situation will occur. Due to the terms of the lease, the Company cannot estimate with any degree of accuracy the costs it may incur during the life of the lease. The Company s net share for the costs of the FPSO in 2005 was approximately $1.8 million.

In May 2003, the Company amended its prior office lease in Englewood, Colorado, which it has committed to through June 2008. The Company s total remaining commitment of this lease is $677,791 at December 31, 2005 ($265,485 in 2006, $273,530 in 2007 and $138,776 in 2008). In December 2003, the Company signed a lease for office space in Houston, Texas, which it has committed to through April 2007 for a total remaining commitment of $135,792 ($101,844 in 2006 and $33,948 in 2007) at December 31, 2005. The total remaining commitment for both offices is $813,583.

During 2005, the Company took a major step toward assuring that the pipeline infrastructure to move the Company s natural gas supplies away from southwest Wyoming will 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 the proposed Rockies Express Pipeline project, sponsored by subsidiaries of Kinder Morgan and Sempra Energy. The Rockies Express Pipeline, if built as proposed, would be the largest natural gas transmission pipeline project of its type built in the United States in more than 20 years, beginning at the Opal Processing Plant in southwest Wyoming and traversing Wyoming and several other states to an ultimate terminus in eastern Ohio. This project is projected to cover more than 1,800 miles and is contemplated to be a large- diameter (42), high-pressure natural gas pipeline. The Rockies Express Pipeline, if built, will be an interstate pipeline and would therefore be subject to the jurisdiction of the United States Federal Energy Regulatory Commission (FERC).

On December 19, 2005, the Company signed two Precedent Agreements with Rockies Express Pipeline, LLC 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 Rockies Express 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 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 the Rockies Express Pipeline LLC 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 anticipated to be completed in stages between 2007 and 2009. Although the Company is optimistic that the Rockies Express Pipeline project will receive the necessary regulatory approvals and be constructed in a timely manner, there can be no assurances that the Rockies Express Pipeline will be built, nor will there be any assurances that, if built, it will prevent large basis differentials from occurring in the future.

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 2005, delay rental costs for all of the Company s leases not held by production were $289,660.

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 $5.50 per Mcf to a monthly high of $8.64 per Mcf during 2005. Realized natural gas prices are derived from the financial statements which include the effects of hedging and natural gas balancing.

The Company may, from time to time, 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 purpose of the swaps is to provide a measure of stability to the Company s cash flows in an environment of volatile oil and gas prices. The derivatives reduce the Company s exposure on the hedged volumes to decreases in commodity prices and limit the benefit the Company might otherwise have received from any increases in commodity prices on the hedged volumes. The Company recognizes all derivative instruments as assets or liabilities on the balance sheet at fair value. The accounting treatment of the changes in fair value as specified in SFAS No. 133 is dependent upon whether or not a derivative instrument is designated as a hedge. For derivatives designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in Other Comprehensive Income (Loss) on the balance sheet until the hedged item is recognized in earnings as oil and gas revenue. For all other derivatives, changes in fair value are recognized in earnings as income or expense. As of December 31, 2005, the Company no longer assesses the future liability of cash flow hedges as all agreements qualifying as such have expired.

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During 2005, the Company recognized costs associated with financially settled swaps to counterparties totaling $9,286,000 as its net realization from hedging activities. This total includes $999,900 for the first quarter of 2005, $1,440,800 for the second quarter of 2005, $2,090,600 for the third quarter of 2005, and $4,754,700 for the fourth quarter of 2005.

At December 31, 2005, the Company had no open derivative contracts to manage price risk on its natural gas production.

The Company also utilizes fixed price forward natural gas sales at southwest Wyoming delivery points to hedge its commodity exposure. In addition to the derivative contracts discussed above, the Company had the following physical delivery contracts in place at December 31, 2005. (The Company s average net interest in physical natural gas sales is approximately 80%.)

Contract Period	Volume MMBTU/Day	Average Price/MMbtu
Calendar 2006	70,000	$ 5.86

As of February 28, 2006, the Company s fixed price forward natural gas sales contracts represented net volumes equal to approximately 24% of the Company s currently forecasted natural gas production for Calendar 2006.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Ultra Petroleum Corp.:

We have audited the accompanying consolidated balance sheets of Ultra Petroleum Corp. and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of operations and retained earnings, shareholders equity and cash flows for each of the years in the three-year period 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 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Ultra Petroleum Corp. and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2005, in accordance with U.S. generally accepted accounting principles.

As explained in Note 1 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, effective January 1, 2003.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 30, 2006 expressed an unqualified opinion on management s assessment of, and an adverse opinion on the effective operation of, internal control over financial reporting.

/s/ KPMG LLP

KPMG LLP

Denver, Colorado
March 30, 2006

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ULTRA PETROLEUM CORP.
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2005	**2004**
	(Expressed in U.S. dollars)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 44,394,775	$ 16,932,661
Restricted cash	213,899	211,961
Accounts receivable	75,656,031	35,749,287
Deferred tax asset		1,327,489
Inventory	22,062,585	5,180,024
Prepaid drilling costs and other current assets	128,044	1,725,843
Total current assets	142,455,334	61,127,265
Oil and gas properties, using the full cost method of accounting		
Proved	612,960,790	385,794,926
Unproved	89,702,465	88,839,460
Capital assets	2,147,528	1,424,367
TOTAL ASSETS	$ 847,266,117	$ 537,186,018
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 49,297,861	$ 14,238,836
Fair value of derivative instruments		3,739,406
Current taxes payable	3,564,990	
Capital cost accrual	46,879,289	53,118,385
Total current liabilities	99,742,140	71,096,627
Long-term debt		102,000,000
Deferred income tax liability	155,746,465	86,362,741
Other long-term obligations	20,576,574	9,734,904
Shareholders equity:		
Common stock no par value; authorized unlimited; issued and outstanding 155,075,864 and 150,234,936 at December 31, 2005 and 2004, respectively	178,806,030	106,513,852
Treasury stock	(1,193,650)	(1,193,650)
Accumulated other comprehensive loss		(2,616,767)
Retained earnings	393,588,558	165,288,311
Total shareholders equity	571,200,938	267,991,746
Commitments and contingencies (Note 11)		
TOTAL LIABILITIES AND SHAREHOLDERS EQUITY	$ 847,266,117	$ 537,186,018

See accompanying notes to consolidated financial statements.

Approved on behalf of the Board:

/s/ Michael D. Watford, Director /s/ James E. Nielson, Director

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ULTRA PETROLEUM CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS

	Year Ended December 31,		
	2005	2004	2003
	(Expressed in U.S. Dollars)		
REVENUES:			
Natural gas sales	$ 422,091,034	$ 224,207,694	$ 114,840,558
Oil sales	94,401,967	34,838,753	6,740,539
	516,493,001	259,046,447	121,581,097
EXPENSES:			
Production expenses and taxes	89,601,686	50,869,283	25,223,679
Depletion, depreciation and amortization	58,102,871	30,249,061	16,215,714
General and administrative	14,342,178	7,075,720	6,751,367
	162,046,735	88,194,064	48,190,760
OPERATING INCOME	354,446,266	170,852,383	73,390,337
OTHER INCOME (EXPENSE):			
Interest income	612,153	90,760	36,889
Interest expense	(3,286,087)	(3,783,070)	(2,850,916)
	(2,673,934)	(3,692,310)	(2,814,027)
INCOME BEFORE INCOME TAXES	351,772,332	167,160,073	70,576,310
Income tax provision	123,472,085	58,010,278	25,253,671
NET INCOME	228,300,247	109,149,795	45,322,639
RETAINED EARNINGS, beginning of year	165,288,311	56,138,516	10,815,877
RETAINED EARNINGS, end of year	$ 393,588,558	$ 165,288,311	$ 56,138,516
NET INCOME PER COMMON SHARE BASIC	$ 1.49	$ 0.73	$ 0.31
NET INCOME PER COMMON SHARE DILUTED	$ 1.41	$ 0.68	$ 0.29
Weighted average common shares outstanding basic	153,100,067	149,735,666	148,198,106
Weighted average common shares outstanding diluted	161,943,400	161,205,534	157,037,878

See accompanying notes to consolidated financial statements.

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ULTRA PETROLEUM CORP.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY

	Shares Issued	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total Shareholders Equity
Balances at December 31, 2002	147,973,336	$ 95,098,690	$ 10,815,877	$ (653,875)	$ (1,193,650)	$ 104,067,042
Stock options exercised	886,000	988,247				988,247
Employee stock plan grants	236,000	1,148,630				1,148,630
Fair value of non-employee stock option grants		212,654				212,654
Comprehensive earnings:						
Net earnings			45,322,639			45,322,639
Change in derivative instruments fair value				(2,286,482)		(2,286,482)
Total comprehensive earnings						43,036,157
Balances at December 31, 2003	149,095,336	97,448,221	56,138,516	(2,940,357)	(1,193,650)	149,452,730
Stock options exercised	1,106,600	1,770,099				1,770,099
Employee stock plan grants	33,000	560,175				560,175
Fair value of non-employee stock option grants		100,550				100,550
Tax benefit of stock options exercised		6,634,807				6,634,807
Comprehensive earnings:						
Net earnings			109,149,795			109,149,795
Change in derivative instruments fair value				323,590		323,590
						109,473,385

Total comprehensive earnings						
Balances at December 31, 2004	150,234,936	106,513,852	165,288,311	(2,616,767)	(1,193,650)	267,991,746
Stock options exercised	4,793,700	20,266,680				20,266,680
Employee stock plan grants	47,228	1,389,380				1,389,380
Fair value of non-employee stock option grants						
Tax benefit of stock options exercised		50,636,118				50,636,118
Comprehensive earnings:						
Net earnings			228,300,247			228,300,247
Change in derivative instruments fair value				2,616,767		2,616,767
Total comprehensive earnings						230,917,014
Balances at December 31, 2005	155,075,864	$ 178,806,030	$ 393,588,558	$	$ (1,193,650)	$ 571,200,938

See accompanying notes to consolidated financial statements.

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ULTRA PETROLEUM CORP.
CONSOLIDATED STATEMENTS OF CASH FLOW

	Year Ended December 31,		
	2005	2004	2003
Cash flows from operating activities:			
Net income	$ 228,300,247	$ 109,149,795	$ 45,322,639
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation and amortization	58,102,871	30,249,061	16,215,714
Deferred income taxes	69,270,977	57,748,452	25,253,671
Tax benefit of stock options exercised	50,636,118		
Stock compensation	2,858,515	923,623	1,018,220
Net changes in working capital:			
Restricted cash	(1,938)	(1,292)	(1,363)
Accounts receivable	(39,906,744)	(16,400,426)	(7,950,378)
Inventory	(518,576)	(275,424)	
Prepaid expenses and other current assets	1,597,799	(14,106)	(1,237,458)
Accounts payable and accrued liabilities	32,518,107	(10,169,082)	10,168,164
Other long-term obligations	7,931,130	3,870,179	1,261,403
Taxation payable	3,564,990	261,826	
Net cash provided by operating activities	414,353,496	175,342,606	90,050,612
Cash flows from investing activities:			
Oil and gas property expenditures	(282,668,055)	(195,598,484)	(115,837,250)
Change in capital costs accrual	(6,239,096)	22,501,473	26,541,083
Inventory	(16,054,472)	9,037,557	(13,589,270)
Purchase of capital assets	(1,585,819)	(954,702)	(737,021)
Net cash (used in) investing activities	(306,547,442)	(165,014,156)	(103,622,458)
Cash flows from financing activities:			
Borrowings of long-term debt, gross	22,000,000	44,000,000	43,000,000
Payments on long-term debt, gross	(124,000,000)	(41,000,000)	(30,000,000)
Proceeds from issuance of common stock	20,266,680	1,770,099	988,247
Stock issued for compensation	1,389,380		
Net cash (used in) provided by financing activities	(80,343,940)	4,770,099	13,988,247
Net increase in cash and cash equivalents	27,462,114	15,098,549	416,401
Cash and cash equivalents, beginning of year	16,932,661	1,834,112	1,417,711
Cash and cash equivalents, end of year	$ 44,394,775	$ 16,932,661	$ 1,834,112
SUPPLEMENTAL INFORMATION			
Cash paid for:			

Interest	$	3,393,279	$	3,783,070	$	2,850,916
Income taxes	$	326,502	$	153,905	$	
Non-cash tax benefit of stock options exercised	$	50,636,118	$	6,634,807	$	

See accompanying notes to consolidated financial statements.

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ULTRA PETROLEUM CORP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Expressed in U.S. dollars unless otherwise noted)
Years ended December 31, 2005, 2004 and 2003
DESCRIPTION OF THE BUSINESS

Ultra Petroleum Corp. (the Company) is an independent oil and gas company engaged in the acquisition, exploration, development, and production of oil and gas properties. The Company is incorporated under the laws of the Yukon Territory, Canada. The Company s principal business activities are in the Green River Basin of southwest Wyoming and Bohai Bay, China.

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 Corporation. The Company presents its financial statements in accordance with U.S. Generally Accepted Accounting Principles (GAAP). All material inter-company transactions and balances have been eliminated upon consolidation.

(b) *Accounting principles:* The consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States.

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

(d) *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.

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

(f) *Oil and 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. Effective with the adoption of Statement of Financial Accounting Standard (SFAS) No. 143 in 2003, the carrying amount of oil and 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 gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a country.

The sum of net capitalized costs and estimated future development costs of oil and gas properties are amortized using the units-of-production method based on the proven reserves as determined by independent petroleum engineers. Oil and gas reserves and production are converted into equivalent units based on relative energy content. Operating fees received related to the properties in which the Company owns an interest are netted against expenses. Fees received in excess of costs incurred are recorded as a reduction to the full cost pool. Effective with the adoption of SFAS No. 143, asset retirement obligations are included in the base costs for calculating depletion.

Oil and 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 on a country-by-country basis 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

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ULTRA PETROLEUM CORP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

occurred. The amount of any impairment is transferred to the capitalized costs being amortized (the depreciation, depletion and amortization (DD&A) pool) or a charge is made against earnings for those international operations where a reserve base has not yet been established. For international operations where a reserve base has not yet been established, an impairment requiring a charge to earnings may be indicated through evaluation of drilling results, relinquishing drilling rights or other information.

Companies that use the full cost method of accounting for oil and 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. 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.

(g) *Inventories:* Crude oil products and 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. Crude oil product inventory at December 31, 2005 and 2004 includes depletion and lease operating expenses (LOE) of $1,456,400 and $628,311, respectively, associated with the Company s crude oil production in China. Drilling and completion supplies inventory of $20.6 million primarily includes the cost of pipe that will be utilized during the 2006 drilling program.

(h) *Derivative transactions:* The Company has entered into commodity price risk management transactions to manage its exposure to natural gas price volatility. These transactions are in the form of fixed price forward natural gas sales contracts with financial institutions and other creditworthy counterparties. These transactions have been designated by the Company as cash flow hedges. As such, unrealized gains and losses related to the change in fair market value of the derivative contracts are recorded in other comprehensive income in the balance sheet to the extent the hedges are effective.

(i) *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.

(j) *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.

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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, 2005, 2004 and 2003: (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,		
	2005	2004	2003
Net income	$ 228,300,247	$ 109,149,795	$ 45,322,639
Weighted average common shares outstanding during the period	153,100,067	149,735,666	148,198,106
Effect of dilutive instruments	8,843,333	11,469,868	8,839,772
Weighted average common shares outstanding during the period including the effects of dilutive instruments	161,943,400	161,205,534	157,037,878
Basic earnings per share	$ 1.49	$ 0.73	$ 0.31
Diluted earnings per share	$ 1.41	$ 0.68	$ 0.29
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	540,000		27,260

(k) *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.

(l) *Reclassifications:* Certain amounts in the financial statements of the prior years have been reclassified to conform to the current year financial statement presentation.

(m) *Accounting for stock-based compensation:* SFAS No. 123 defines a fair value method of accounting for employee stock options and similar equity instruments. SFAS No. 123 allows for the continued measurement of compensation cost for such plans (see Note 6) using the intrinsic value based method prescribed by APB Opinion No. 25 (APB Opinion 25), Accounting for Stock Issued to Employees , provided that pro forma results of operations are disclosed for those options granted. The Company accounts for stock options granted to employees and directors of the Company under the intrinsic value method and no compensation expense is recognized when the exercise price of options equals or is greater than the fair market value of the underlying stock on the date of grant. Had the Company reported compensation costs as

ULTRA PETROLEUM CORP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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:

	For the Year Ended December 31,		
	2005	2004	2003
Net income:			
As reported	$ 228,300,247	$ 109,149,795	$ 45,322,639
Deduct: Fair value of stock options issued, net of tax	(13,511,140)	(17,714,486)	(1,522,968)
Pro forma	$ 214,789,107	$ 91,435,309	$ 43,799,671
Net income per common share:			
Basic earnings per share:			
As reported	$ 1.49	$ 0.73	$ 0.31
Pro forma	$ 1.40	$ 0.61	$ 0.30
Diluted earnings per share:			
As reported	$ 1.41	$ 0.68	$ 0.29
Pro forma	$ 1.33	$ 0.57	$ 0.28

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: at December 31, 2005 expected volatility of 34.8% to 44.9% and a risk free rate of 4.18% to 4.41%; at December 31, 2004 expected volatility of 38.4% and a risk free rate of 3.713%; and at December 31, 2003, expected volatility of 25.0% and a risk free rate of 4.35%. At December 31, 2005 options have expected lives of 1.9 years, at December 31, 2004 options had expected lives of 6.5 years, and December 31, 2003 options had expected lives of 10 years. At December 31, 2005, all stock options issued to date have fully vested.

In the fourth quarter of 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123 (revised 2004), or SFAS No. 123R, Share-Based Payment, which replaces SFAS No. 123 and supersedes APB Opinion 25. SFAS No. 123R eliminates the option to use APB Opinion 25 s intrinsic value method of accounting and requires recording expense for stock compensation based on a fair value based method. After a phase-in period for SFAS No. 123R, pro forma disclosure will no longer be allowed. In the first quarter of 2005, the SEC issued Staff Accounting Bulletin No. 107 which provided further clarification on the implementation of SFAS No. 123R.

Alternative phase-in methods are allowed under Statement No. 123R and the Company s effective date for implementation of SFAS No. 123R is January 1, 2006. The Company expects it will use the modified-prospective phase-in method that requires entities to recognize compensation costs in financial statements issued after the date of adoption for all share-based payments granted, modified or settled after the date of adoption as well as for any awards that were granted prior to the adoption date for which the required service has not yet been performed. The Company does not believe that any of the alternative phase-in methods would have a materially different effect on the Company s Consolidated Statement of Operations or Balance Sheet.

(n) *Revenue Recognition.* Within the Company s United States segment, 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

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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, 2005 the Company had a net natural gas imbalance liability of $0.5 million and at December 31, 2004, the Company had a net natural gas imbalance receivable of $2.0 million.

In China, revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title is transferred.

(o) *Accumulated Other Comprehensive Earnings (Loss):* Other comprehensive earnings (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). The loss depicted on the balance sheet as other comprehensive loss is associated with unrealized losses related to the change in fair value of derivative instruments designated as cash flow hedges.

	Year Ended December 31,		
	2005	**2004**	**2003**
Net income	$ 228,300,247	$ 109,149,795	$ 45,322,639
Unrealized loss on derivative instruments, net of tax		(2,616,767)	(2,940,357)
Effect of dilutive instruments	$ 228,300,247	$ 106,533,028	$ 42,382,282

(p) *Impact of recently issued accounting pronouncements:* In December 2004, the FASB issued a revised SFAS No. 123 (SFAS 123R). SFAS 123R requires compensation costs related to share-based payments to be recognized in the income statement over the vesting period. The amount of the compensation cost will be measured based on the grant-date fair value of the instrument issued. SFAS 123R is effective as of January 1, 2006, for all awards granted or modified after that date and for those awards granted prior to that date that have not vested. Beginning January 1, 2006 the Company will begin expensing share based compensation. All outstanding awards issued prior to this date have fully vested. Stock compensation expensed in 2005, 2004 and 2003 has been included within the general and administrative line item of the Company s income statement. For the years ended December 31, 2005, 2004 and 2003, stock compensation expense was $2,858,515, $923,623 and $1,018,220, respectively.

As of January 1, 2006, the Company will be required to adopt SFAS No. 154, Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and SFAS No. 3 (SFAS No. 154). SFAS No. 154 requires retrospective application of voluntary changes in accounting principles, unless it is impracticable. The Company does not expect this standard to have a material impact on its financial statements.

2. ASSET RETIREMENT OBLIGATIONS:

In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143). SFAS No. 143 requires the Company 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, 2005, the Company has recorded a liability of $3,601,348 ($2,845,724 U.S. and $755,624 China) to account for future obligations associated with its assets in both the United States and China. As of December 31, 2004, the liability was $744,512 ($321,505 U.S. and $423,007 China).

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The following table summarizes the activities for the Company s asset retirement obligations for the year ended December 31, 2005:

		December 31, 2005
Asset retirement obligations at beginning of period	$	744,512
Accretion expense		47,519
Liabilities incurred		844,977
Liabilities settled		(53,705)
Revisions of estimated liabilities		2,018,045
Asset retirement obligations at end of period		3,601,348
Less: current asset retirement obligations		
Long-term asset retirement obligations	$	3,601,348

3. OIL AND GAS PROPERTIES:

		December 31, 2005		December 31, 2004
Developed Properties:				
Acquisition, equipment, exploration, drilling and environmental costs Domestic	$	700,425,880	$	435,095,908
Acquisition, equipment, exploration, drilling and environmental costs China		43,890,413		24,552,316
Less accumulated depletion, depreciation and amortization Domestic		(118,172,467)		(70,597,411)
Less accumulated depletion, depreciation and amortization China		(13,183,036)		(3,255,887)
		612,960,790		385,794,926
Unproven Properties:				
Acquisition and exploration costs Domestic		17,647,300		16,910,010
Acquisition and exploration costs China		72,055,165		71,929,450
	$	702,663,255	$	474,634,386

The Company holds interests in projects located in both the United States and in China. Costs related to these interests of $89.7 million ($17.6 million in the U.S. and $72.1 million in China) are not being depleted pending determination of existence of estimated proved reserves. The Company s share of exploration on its China properties accounts for the majority of this balance. The properties in China began producing in July 2004 and development of additional fields continues along with exploration of future fields. The Company will

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

continue to assess and allocate the unproven properties over the next several years as proved reserves are established and as exploration dictates whether or not future areas will be developed.

	Total	2005	2004	2003	Prior
United States:					
Acquisition costs	$ 18,606,405	$ 1,818,954	$ 222,685	$ 418,064	$ 16,146,702
Exploration costs	7,477,887	545,602	1,082,804	995,612	4,853,869
Less transfers to proved	(8,436,992)	(1,627,266)		(128,139)	(6,681,587)
	17,647,300	737,290	1,305,489	1,285,537	14,318,984
China:					
Acquisition costs	44,857,346				44,857,346
Exploration costs	67,911,028	19,167,259	29,390,964	8,862,000	10,490,805
Less transfers to proved	(40,713,209)	(19,041,544)	(21,671,665)		
	72,055,165	125,715	7,719,299	8,862,000	55,348,151
Total	$ 89,702,465	$ 863,005	$ 9,024,788	$ 10,147,537	$ 69,667,135

4. CAPITAL ASSETS:

	December 31, 2005 Cost	December 31, 2005 Accumulated Depreciation	December 31, 2005 Net Book Value	December 31, 2004 Net Book Value
Computer equipment	$ 1,000,516	$ 688,632	$ 311,884	$ 221,261
Office equipment	277,142	188,757	88,385	88,339
Field equipment	1,534,442	508,527	1,025,915	329,264
Other	2,482,917	1,761,573	721,344	785,503
	$ 5,295,017	$ 3,147,489	$ 2,147,528	$ 1,424,367

5. LONG-TERM LIABILITIES:

	December 31, 2005	December 31, 2004
Bank indebtedness	$	$ 102,000,000
Other long-term obligations	20,576,574	9,734,904
	$ 20,576,574	$ 111,734,904

Bank indebtedness: The Company (through its subsidiary) participates in a revolving credit facility with a group of banks led by JP Morgan Chase Bank, N.A. The agreement specifies a maximum loan amount of $500 million and an aggregate borrowing base of $800 million and a commitment amount of $200 million at November 14, 2005. The commitment amount may be increased up to the lesser of the borrowing base amount or $500 million at any time at the request of the Company. Each bank shall have the right, but not the obligation, to increase the amount of their commitment as requested by the Company. In the event that the existing banks increase their commitment to an amount less than the requested commitment amount, then it would be necessary to bring additional banks into the facility. At December 31, 2005, the Company had no amounts outstanding and $200 million unused and available under the current committed amount.

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The credit facility matures on May 1, 2010. The note bears interest at either (A) the bank s prime rate plus a margin of zero percent (0.00%) to three-quarters of one percent (0.75%) based on the percentage of available credit drawn or at (B) LIBOR plus a margin of one percent (1.00%) to one and three-quarters of one percent (1.75%) based on the percentage of available credit drawn. For the purposes of calculating interest, the available credit is equal to the borrowing base. An average annual commitment fee of 0.25% to 0.375%, depending on the percentage of available credit drawn, is charged quarterly for any unused portion of the commitment amount. The Company s total commitment fees were $354,017, $374,096 and $249,788 for the years ended December 31, 2005, 2004 and 2003, respectively.

The borrowing base is subject to periodic (at least semi-annual) review and re-determination by the banks and may be decreased or increased depending on a number of factors, including the Company s proved reserves and the bank s forecast of future oil and gas prices. If the borrowing base is reduced to an amount less than the balance outstanding, the Company has sixty days from the date of written notice of the reduction in the borrowing base to pay the difference. Additionally, the Company is subject to quarterly reviews of compliance with the covenants under the bank facility including minimum coverage ratios relating to interest, working capital and advances to Sino-American Energy Corporation. In the event of a default under the covenants, the Company may not be able to access funds otherwise available under the facility. As of December 31, 2005, the Company was in compliance with required ratios of the bank facility.

The debt outstanding, if any, under the credit facility is secured by a majority of the Company s proved domestic oil and gas properties.

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

6. STOCK BASED COMPENSATION:

The Company s Stock Incentive Plans are administered by 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 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 covering an aggregate of more than 500,000 common shares. The Plan Administrator determines the vesting requirements and any vesting restrictions or forfeitures 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 weighted average trading price of the common shares for the five trading days preceding the date of the award.

On April 29, 2005, the shareholders approved the adoption of the 2005 Stock Incentive Plan (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

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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 following table summarizes the changes in stock options for the three-year period ended December 31, 2005:

	Number of Options		Weighted Average Exercise Price (US$)
Balance, December 31, 2002	11,123,500	$	0.26 to $4.43
Granted	1,595,000	$	4.83 to $7.10
Exercised	(886,000)	$	0.32 to $4.43
Cancelled	(27,500)	$	4.43 to $4.83
Balance, December 31, 2003	11,805,000	$	0.26 to $7.10
Granted	2,005,000	$	11.69 to $24.31
Exercised	(1,106,600)	$	0.38 to $7.10
Balance, December 31, 2004	12,703,400	$	0.26 to $24.31
Granted	1,529,000	$	23.90 to $58.71
Exercised	(4,793,700)	$	0.32 to $25.68
Cancelled	(50,000)	$	25.68 to $25.68
Balance, December 31, 2005	9,388,700	$	0.26 to $58.71

No compensation resulted from the granting of these options as all were granted at or above the market value of the common shares at the date of grant. Stock options granted to consultants have been assessed at fair value and capitalized to the full cost pool based on the nature of the services provided by the consultants. At December 31, 2005, all stock options granted to date were fully vested.

The following table summarizes information about the stock options outstanding at December 31, 2005.

	Options Outstanding				Options Exercisable			
Range of Exercise Price ($US)	Number Outstanding	Weighted Average Remaining Contractual Life		Weighted Average Exercise Price ($US)	Number Exercisable	Weighted Average Remaining Contractual Life		Weighted Average Exercise Price ($US)
$ 0.38 - 0.46	2,627,500	3.08	$	0.46	2,627,500	3.08	$	0.46
$ 0.25 - 0.57	823,000	4.30	$	0.36	823,000	4.30	$	0.36
$ 1.49 - 2.61	1,405,000	5.21	$	1.91	1,405,000	5.21	$	1.91

$ 3.91 - 4.43	722,000	6.36	$	4.39	722,500	6.36	$	4.39
$ 4.83 - 7.10	941,200	7.35	$	5.04	941,200	7.35	$	5.04
$11.68 - 24.21	1,484,000	8.31	$	16.06	1,484,000	8.31	$	16.06
$23.90 - 58.71	1,386,000	9.48	$	35.28	1,386,000	9.48	$	35.28

In December 2004, the FASB issued SFAS No. 123R, Share-Based Payments (SFAS No. 123R). SFAS No. 123R is a revision of SFAS No. 123, Accounting for Stock Based Compensation , and supersedes APB Opinion 25. Among other items, SFAS No. 123R eliminates the use of APB Opinion 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the financial statements. Pro forma disclosure is no longer an alternative under the new standard. The Company will adopt SFAS No. 123R as of the required effective date for calendar year companies, which is January 1, 2006.

SFAS No. 123R permits companies to adopt its requirements using either a modified prospective method, or a modified retrospective method. Under the modified prospective method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS No. 123R for all share-based payments granted after that date, and based on the requirements of SFAS No. 123 for all unvested awards granted prior to the effective date of SFAS No. 123R. Under the modified retrospective method, the requirements are the same as under the modified prospective method, but also permit entities to restate financial statements of previous periods based on proforma disclosures made in accordance with SFAS No. 123. At December 31, 2005, all stock options granted to date were fully vested.

The Company currently utilizes a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to Employees. While SFAS No. 123R permits entities to continue to use such a model, the standard also permits the use of a more complex binomial, or lattice model. Based upon research done by the Company on the alternative models available to value option grants, and in conjunction with the type and number of stock options expected to be issued in the future, the Company has determined that it will continue to use the Black-Scholes model for option valuation as of the current time.

SFAS No. 123R includes several modifications to the way that income taxes are recorded in the financial statements. The expense for certain types of option grants is only deductible for tax purposes at the time that the taxable event takes place, which could cause variability in the Company s effective tax rates recorded throughout the year. SFAS No. 123R does not allow companies to predict when these taxable events will take place. Furthermore, it requires that the benefits associated with the tax deductions in excess of recognized compensation cost be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement will reduce net operating cash flows and increase net financing cash flows in periods after the effective date. These future amounts cannot be estimated, because they depend on, among other things, when employees exercise stock options.

7. DERIVATIVE FINANCIAL INSTRUMENTS:

The Company has, in the past, used 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 purpose of the swaps is to provide a measure of stability to the Company s cash flows in an environment of volatile oil and gas prices. The derivatives reduce the Company s exposure on the hedged volumes to decreases in commodity prices and limit the benefit the Company might otherwise have received from any increases in commodity prices on the hedged volumes. The Company recognizes all derivative instruments as assets or liabilities in the balance sheet at fair value. The accounting treatment for the changes in fair value as specified in SFAS No. 133 is dependent upon whether or not a derivative instrument is designated as a hedge. For derivatives designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in Other Comprehensive Income (Loss) on the balance sheet until the hedged item is recognized in earnings as oil and gas revenue. For all other derivatives, changes in fair value are recognized in earnings as income or expense.

During 2005, the Company recognized costs associated with financially settled swaps to counter-parties totaling $9,286,000 as its net realization from hedging activities. This total includes $999,900 for the first quarter of 2005, $1,440,800 for the second quarter of 2005, $2,090,600 for the third quarter of 2005, and $4,754,700 for the fourth quarter of 2005.

At December 31, 2005, the Company had no open derivative contracts to manage price risk on its natural gas production.

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The Company also utilizes fixed price forward natural gas sales at southwest Wyoming delivery points to hedge its commodity exposure. The Company had the following physical delivery contracts in place at December 31, 2005.

Contract Period	Volume MMBTU/Day	Average Price/MMbtu
Calendar 2006	70,000	$ 5.86

As of February 28, 2006, the Company s fixed price forward natural gas sales contracts represented net volumes equal to approximately 24% of the Company s currently forecasted natural gas production for Calendar 2006.

8. INCOME TAXES:

Income before income taxes is as follows:

	Year Ended December 31,		
	2005	2004	2003
United States	$ 304,943,491	$ 153,553,816	$ 70,970,170
Foreign	46,828,841	13,606,257	(393,860)
Total	$ 351,772,332	$ 167,160,073	$ 70,576,310

The consolidated income tax provision is comprised of the following:

	Year Ended December 31,		
	2005	2004	2003
Current:			
U.S. federal & state	$ 50,636,118	$ 261,826	
Foreign	3,564,990		
Deferred:			
U.S. federal & state	57,228,294	53,144,257	25,253,671
Foreign	12,042,683	4,604,195	
Total income tax provision	$ 123,472,085	$ 58,010,278	$ 25,253,671

During 2005, the Company realized tax benefits of $50.6 million attributable to tax deductions associated with the exercise of stock options. These benefits are recorded as a reduction of current taxes payable and as an increase in shareholders equity.

The income tax provision 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,

	2005	2004	2003
Income tax provision computed at the U.S. statutory rate	$ 123,120,316	$ 58,506,026	$ 24,701,708
State income tax provision net of federal benefit	297,319	159,628	455,557
Other, net	54,450	(655,376)	96,406
	$ 123,472,085	$ 58,010,278	$ 25,253,671

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

	Year Ended December 31,	
	2005	**2004**
Deferred tax assets:		
Unrecognized loss on derivative instruments (current)	$	$ 1,327,489
U.S. federal net operating loss carryforwards		5,845,351
Foreign net operating loss carryforwards	1,976,930	2,554,106
Unrecognized loss on derivative instruments (noncurrent)		112,747
Other, net	4,469	1,009,305
	1,981,399	10,848,998
Valuation allowance	(1,976,930)	(2,554,106)
Net deferred tax assets	4,469	8,294,892
Deferred tax liabilities:		
Property and equipment	(155,750,934)	(93,330,144)
Net deferred tax asset (liability)	$ (155,746,465)	$ (85,035,252)

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.

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 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 expire. 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 $5.6 million and $7.3 million as of December 31, 2005 and December 31, 2004, 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 $5.6 million Canadian loss carryforward will expire between 2006 and 2015.

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, 2005 and December 31, 2004 attributable to this deferred tax asset.

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, 2005, the Company had no open derivative contracts; and, therefore, no recorded tax benefit attributable to unrecognized loss on derivative instruments. A tax benefit attributable to unrecognized loss on

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derivative instruments of $1,440,236 was allocated directly to Other Comprehensive Income as of December 31, 2004.

9. 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 plan operates on a calendar year basis and began in February 1998. The expense associated with the Company s contribution was $507,306, $396,684 and $299,832 for the years ended December 31, 2005, 2004 and 2003, respectively.

10. SEGMENT INFORMATION:

The Company has two reportable operating segments, one domestic and one foreign, which are in the business of natural gas and crude oil exploration and production. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. The Company evaluates performance based on profit or loss from oil and gas operations before price-risk management and other, general and administrative expenses and interest expense. The Company s reportable operating segments are managed separately based on their geographic locations. Financial information by operating segment is presented below:

	United States	China	Total
Year-ended December 31, 2005			
Oil and gas sales	$ 448,730,965	$ 67,762,036	$ 516,493,001
Costs and Expenses:			
Depletion, depreciation and amortization	48,455,070	9,647,801	58,102,871
Lease operating expenses	9,047,390	7,352,000	16,399,390
Production taxes	52,689,060	3,388,089	56,077,149
Gathering	17,125,147		17,125,147
Operating income	$ 321,414,298	$ 47,374,146	$ 368,788,444
General and administrative			14,342,178
Other expense, net			2,673,934
Income before income taxes			$ 351,772,332
Capital expenditures	$ 263,486,693	$ 19,181,362	$ 282,668,055
Net oil and gas properties	$ 599,900,713	$ 102,762,542	$ 702,663,255

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ULTRA PETROLEUM CORP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	China	Total
Year-ended December 31, 2004			
Oil and gas sales	$ 238,866,913	$ 20,179,534	$ 259,046,447
Costs and Expenses:			
Depletion, depreciation and amortization	27,346,061	2,903,000	30,249,061
Lease operating expenses	6,286,715	2,286,000	8,572,715
Production taxes	28,151,661	1,009,098	29,160,759
Gathering	13,135,809		13,135,809
Operating income	$ 163,946,667	$ 13,981,436	$ 177,928,103
General and administrative			7,075,720
Other expense, net			3,692,310
Income before income taxes			$ 167,160,073
Capital expenditures	$ 179,592,969	$ 16,005,515	$ 195,598,484
Net oil and gas properties	$ 381,408,507	$ 93,225,879	$ 474,634,386

	United States	China	Total
Year-ended December 31, 2003			
Oil and gas sales	$ 121,581,097		$ 121,581,097
Costs and Expenses:			
Depletion, depreciation and amortization	16,215,714		16,215,714
Lease operating expenses	3,627,639		3,627,639
Production taxes	13,767,668		13,767,668
Gathering	7,828,372		7,828,372
Operating income	$ 80,141,704	$	$ 80,141,704
General and administrative			6,751,367
Other expense, net			2,814,027
Income before income taxes			$ 70,576,310
Capital expenditures	$ 100,677,192	$ 15,160,058	$ 115,837,250
Net oil and gas properties	$ 226,893,478	$ 80,970,244	$ 307,863,722

11. COMMITMENTS AND CONTINGENCIES:

On October 16, 2003 the operator of the Company s properties in China, Kerr-McGee, signed a 15 year contract, which provides for up to an additional 10 years, to lease a floating production storage offloading unit (FPSO). The Company ratified the contract for its net share which is 8.91%. The FPSO service agreement calls for a day rate lease payment and a sliding scale per barrel processing fee that decreases based on cumulative barrels processed. The lease contains a cancellation fee based on a sliding time-scale (cancellation fee decreases with time), which as of December 31, 2005 was $3.3 million net to the Company s 8.91% interest. The Company considers it very unlikely that a lease cancellation situation will occur. Due to the terms of the lease, the Company cannot estimate with any degree of accuracy the costs it may incur during the life of the lease. The Company s net share for the costs of the FPSO in 2005 was approximately $1.8 million.

ULTRA PETROLEUM CORP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In May 2003, the Company amended its prior office lease in Englewood, Colorado, which it has committed to through June 2008. The Company s total remaining commitment at December 31, 2005 on this lease is $677,791 at December 31, 2005 ($265,485 in 2006, $273,530 in 2007 and $138,776 in 2008). In December 2003, the Company signed a lease for office space in Houston, Texas, which it has committed to through April 2007 for a total remaining commitment of $135,792 ($101,844 in 2006 and $33,948 in 2007) at December 31, 2005. The total remaining commitment for both offices is $813,583.

As of December 31, 2005, the Company had committed to drilling obligations with certain rig contractors totalling $108,410,500 with $104,610,500 due in one to three years and the balance of $3,800,000 due in three to five years. The commitments expire in 2009 and were entered into to fulfill the Company s 2006-2008 drilling program initiatives in Wyoming.

During 2005, the Company took a major step toward assuring that the pipeline infrastructure to move the Company s natural gas supplies away from southwest Wyoming will 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 the proposed Rockies Express Pipeline project, sponsored by subsidiaries of Kinder Morgan and Sempra Energy. The Rockies Express Pipeline, if built as proposed, would be the largest natural gas transmission pipeline project of its type built in the United States in more than 20 years. As proposed, the Rockies Express Pipeline would begin at the Opal Processing Plant in southwest Wyoming, and traverse Wyoming and several other states to an ultimate terminus in eastern Ohio. This project is projected to cover more than 1,800 miles and is contemplated to be a large-diameter (42), high-pressure natural gas pipeline. The Rockies Express Pipeline, if built, will be an interstate pipeline and would therefore be subject to the jurisdiction of the United States Federal Energy Regulatory Commission.

On December 19, 2005, the Company signed, subject to Board of Director approval, a Precedent Agreement with Rockies Express Pipeline, LLC committing to take firm transportation capacity in the proposed Rockies Express interstate pipeline. 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 Rockies Express certain demand charges related to its rights to hold this firm transportation capacity as an anchor shipper. The Company s Board of Directors approved the Precedent Agreement on February 6, 2006 and Kinder Morgan, as the Managing Member of the Rockies Express Pipeline LLC advised the Company of their final approval of the Precedent Agreement, and their intent to proceed with the construction of the Rockies Express Pipeline on February 28, 2006. Although the Company is optimistic that the Rockies Express Pipeline project will receive the necessary regulatory approvals and be constructed in a timely manner, there can be no assurances that the Rockies Express Pipeline will be built, nor will there be any assurances that, if built, it will prevent large basis differentials from occurring in the future.

The Company is currently involved in various routine disputes and allegations incidental to its business operations. While it is not possible to determine the ultimate disposition of these matters, management, after consultation with legal counsel, is of the opinion that the final resolution of all such currently pending or threatened litigation is not likely to have a material adverse effect on the consolidated financial position, results of operations or cash flows of the Company.

12. 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 maturity of these financial instruments.

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

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ULTRA PETROLEUM CORP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

conditions. In 2005, the Company had three significant customers, CNOOC, Occidental Energy Marketing, Inc. and Sempra Energy Trading, that individually accounted for 10% or more of the Company s total natural gas and oil sales during 2005.

13. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED):

	Revenues	Expenses	Income Before Income Tax Provision	Income Tax Provision	Net Income	Basic Earnings per Share	Diluted Earnings per Share
	(In thousands, except for per share data)						
2005							
First Quarter	$ 89,364	$ 31,857	$ 57,507	$ 20,185	$ 37,322	$ 0.25	$ 0.23
Second Quarter	$ 110,635	$ 36,848	$ 73,787	$ 25,899	$ 47,888	$ 0.31	$ 0.30
Third Quarter	$ 134,378	$ 40,618	$ 93,760	$ 32,910	$ 60,850	$ 0.40	$ 0.38
Fourth Quarter	$ 182,116	$ 55,398	$ 126,718	$ 44,478	$ 82,240	$ 0.53	$ 0.50
	$ 516,493	$ 164,721	$ 351,772	$ 123,472	$ 228,300		
2004							
First Quarter	$ 48,619	$ 17,947	$ 30,672	$ 10,888	$ 19,784	$ 0.13	$ 0.12
Second Quarter	$ 46,110	$ 17,393	$ 28,717	$ 10,195	$ 18,522	$ 0.12	$ 0.12
Third Quarter	$ 66,849	$ 23,261	$ 43,588	$ 15,713	$ 27,875	$ 0.19	$ 0.17
Fourth Quarter	$ 97,468	$ 33,285	$ 64,183	$ 21,214	$ 42,969	$ 0.29	$ 0.26
	$ 259,046	$ 91,886	$ 167,160	$ 58,010	$ 109,150		

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

The following information about the Company s oil and 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 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, 2005, 2004 and 2003 are based upon estimates prepared by Netherland, Sewell & Associates, Inc. dated January 27, 2006, January 24, 2005 and January 23, 2004, respectively. The estimates for properties in China were prepared by Ryder Scott Company in a report dated January 31, 2006 and February 11, 2005. These are estimated quantities of proved oil and gas reserves for the Company and the changes in total proved reserves as of December 31, 2005, 2004 and 2003. All such reserves are located in the Green River Basin, Wyoming and Bohai Bay, China.

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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, 2002	5,559,000	667,121,000			5,559,000	667,121,000
Extensions, discoveries and additions	2,894,700	361,298,700			2,894,700	361,298,700
Production	(211,600)	(27,621,800)			(211,600)	(27,621,800)
Revisions	100,400	22,569,400			100,400	22,569,400
Reserves, December 31, 2003	8,342,500	1,023,367,300			8,342,500	1,023,367,300
Extensions, discoveries and additions	4,520,000	562,548,000	8,180,900		12,700,900	562,548,000
Production	(349,700)	(43,667,400)	(624,560)		(943,000)	(43,667,400)
Revisions	(1,123,700)(1)	(128,247,300)(2)	31,228		(1,123,700)	(128,247,300)
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)(3)	(132,727,000)(4)	(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
Proved developed reserves:						
December 31, 2002	2,003,000	222,608,000				222,608,000
December 31, 2003	3,028,000	359,072,000				359,072,000
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

(1) Revision amount of 936,500 attributable to 40 wells dropped from PUD category replaced by more attractive wells.

(2) Revision amount of 117,064,000 associated with above 40 mentioned wells.

(3) Revision amount of 412,500 attributable to 26 wells dropped from PUD category replaced by more attractive wells.

(4) Revision amount of 51,560,000 associated with above mentioned 26 wells.

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ULTRA PETROLEUM CORP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

C. *STANDARDIZED MEASURE (US$000):*

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 $8.00, $5.46, and $5.59 per Mcf of natural gas at December 31, 2005, 2004 and 2003, respectively. The calculated weighted average oil price at December 31, 2005, 2004, and 2003 for Wyoming was $60.81, $42.80 and 31.87 respectively. The calculated weighted average crude oil price at December 31, 2005 and 2004 for China was a Duri price of $48.74 and $29.46, 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, 2003			
Future cash inflows	$ 5,986,603	$	$ 5,986,603
Future production costs	(1,171,314)		(1,171,314)
Future development costs	(358,811)		(358,811)
Future income taxes	(1,620,437)		(1,620,437)
Future net cash flows	2,836,041		2,836,041
Discounted at 10%	(1,700,528)		(1,700,528)
Standardized measure of discounted future net cash flows	$ 1,135,513	$	$ 1,135,513
As of December 31, 2004 Future cash inflows	$ 8,213,061	$ 223,531	$ 8,436,592
Future production costs	(1,699,891)	(67,387)	(1,767,278)
Future development costs	(623,539)	(18,382)	(641,921)
Future income taxes	(1,988,387)	(21,436)	(2,009,823)
Future net cash flows	3,901,244	116,326	4,017,570
Discounted at 10%	(2,285,779)	(62,455)	(2,348,234)
Standardized measure of discounted future net cash flows	$ 1,615,465	$ 53,871	$ 1,669,336
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

ULTRA PETROLEUM CORP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

D. *SUMMARY OF CHANGES IN THE STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS (US$000):*

	December 31, 2005	December 31, 2004	December 31, 2003
Standardized measure, beginning	$ 1,669,336	$ 1,135,513	$ 316,965
Net revisions	(436,425)	(245,950)	41,715
Extensions, discoveries and other changes	2,306,982	1,062,236	680,136
Changes in future development costs	(130,727)	(123,051)	(10,603)
Sales of oil and gas, net of production costs	(426,891)	(216,670)	(96,357)
Net change in prices and production costs	1,992,707	2,645	605,892
Development costs incurred during the period that reduce future development costs	172,962	96,220	8,886
Accretion of discount	254,236	178,431	47,353
Net change in income taxes	(1,825,686)	(220,038)	(458,474)
Standardized measure, ending	$ 3,576,494	$ 1,669,336	$ 1,135,513

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 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 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 gas prices have fluctuated widely.

E. *COSTS INCURRED IN OIL AND GAS EXPLORATION AND DEVELOPMENT ACTIVITIES (US$000):*

UNITED STATES

	Years Ended		
	December 31, 2005	December 31, 2004	December 31, 2003
Acquisition costs unproved properties	$ 775	$ 1,268	$ 1,603
Exploration	56,894	97,068	55,095

Development		208,173		82,646		43,111
Total	$	265,842	$	180,982	$	99,809

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ULTRA PETROLEUM CORP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CHINA

	Years Ended		
	December 31, 2005	December 31, 2004	December 31, 2003
Acquisition costs unproved properties	$ 2,876	$ 2,351	$ 16,027
Exploration			
Development	16,465	12,657	
Total	$ 19,341	$ 15,008	$ 16,027

TOTAL

	Years Ended		
	December 31, 2005	December 31, 2004	December 31, 2003
Acquisition costs unproved properties	$ 3,651	$ 3,619	$ 17,630
Exploration	56,894	97,068	55,095
Development	224,638	95,303	43,111
Total	$ 285,183	$ 195,990	$ 115,836

F. *RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES (US$000):*

UNITED STATES

	Years Ended		
	December 31, 2005	December 31, 2004	December 31, 2003
Oil and gas revenue	$ 448,731	$ 238,867	$ 121,581
Production expenses and taxes	(78,861)	(47,574)	(25,224)
Depletion and depreciation	(48,456)	(27,346)	(16,216)
Deferred income taxes	(107,916)	(53,406)	(25,254)
Total	$ 213,498	$ 110,541	$ 54,887

CHINA

	Years Ended		
	December 31, 2005	December 31, 2004	December 31, 2003
Oil and gas revenue	$ 67,762	$ 20,180	$
Production expenses and taxes	(10,740)	(3,295)	
Depletion and depreciation	(9,648)	(2,903)	
Deferred income taxes	(15,556)	(4,604)	
Total	$ 31,818	$ 9,378	$

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ULTRA PETROLEUM CORP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

TOTAL

	Years Ended		
	December 31, 2005	December 31, 2004	December 31, 2003
Oil and gas revenue	$ 516,493	$ 259,047	$ 121,581
Production expenses and taxes	(89,601)	(50,869)	(25,224)
Depletion and depreciation	(58,104)	(30,249)	(16,216)
Deferred income taxes	(123,472)	(58,010)	(25,254)
Total	$ 245,316	$ 119,919	$ 54,887

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

	December 31, 2005	December 31, 2004
Developed Properties:		
Acquisition, equipment, exploration, drilling and environmental costs Domestic	$ 700,425,880	$ 435,095,908
Acquisition, equipment, exploration, drilling and environmental costs China	43,890,413	24,552,316
Less accumulated depletion, depreciation and amortization Domestic	(118,172,467)	(70,597,411)
Less accumulated depletion, depreciation and amortization China	(13,183,036)	(3,255,887)
	612,960,790	385,794,926
Unproven Properties:		
Acquisition and exploration costs Domestic	17,647,300	16,910,010
Acquisition and exploration costs China	72,055,165	71,929,450
	$ 702,663,255	$ 474,634,386

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

None.

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

(a) Evaluation of Disclosure Controls and Procedures

The Company maintains disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) designed to ensure that information required to be disclosed in the Company s reports under the Securities Exchange Act of 1934, as amended (Exchange Act), is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms and that such information is accumulated and communicated to management, including the Company s Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives.

In connection with the preparation of this Annual Report on Form 10-K, an evaluation was performed under the supervision and with the participation of the Company s management, including the CEO and CFO, of the effectiveness of the design and operation of the Company s disclosure controls and procedures. Based on that evaluation, the Company s CEO and CFO concluded that the Company s disclosure controls and procedures were not effective as of December 31, 2005, because of the material weaknesses described below.

(b) Management s Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate 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. 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 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.

A material weakness is a control deficiency or combination of control deficiencies that results in a more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. As of December 31, 2005, the Company identified the following material weaknesses:

- The Company did not maintain effective company level controls. Specifically, (i) certain of its accounting personnel in key roles did not possess an appropriate level of technical expertise, and (ii) the Company s monitoring of the internal audit function was not sufficient to provide management a basis to assess the quality of the Company s internal control performance over time. These deficiencies resulted in more than a remote likelihood that a material misstatement of the Company s annual or interim financial statements would not be prevented or detected.

- The Company did not have adequate policies and procedures regarding supervisory review of account reconciliations and account and transaction analyses. This deficiency resulted in the following material errors in the Company s preliminary 2005 consolidated financial statements:
  - misclassification of costs between proved and unproved oil and gas properties and understatement of depletion expense;
  - improper reporting of value added taxes;
  - understatement of asset retirement obligations;
  - overstatement in tubular inventory;
  - understatement of capitalized well cost accrued liabilities; and

overstatement of accounts receivable.

These errors have been corrected by management prior to the issuance of the Company s 2005 consolidated financial statements.

The Company did not have adequate policies and procedures to ensure that accurate and reliable interim and annual consolidated financial statements were prepared and reviewed on a timely basis. Specifically, the Company did not have:

sufficient personnel with the skills and experience in the application of U.S. generally accepted accounting principles; and

policies and procedures regarding the preparation and management review of footnote disclosures accompanying the Company s financial statements.

As a result of these deficiencies, material errors were identified in the footnotes to the Company s preliminary 2005 consolidated financial statements. These errors have been corrected by management prior to the issuance of the Company s 2005 consolidated financial statements.

As a result of the aforementioned material weaknesses, management has concluded that the Company did not maintain effective internal control over financial reporting as of December 31, 2005, based on the criteria in *Internal Control Integrated Framework* issued by the COSO.

The Company s independent registered public accountants, KPMG LLP, have audited and issued a report on management s assessment of the Company s internal control over financial reporting, which report appears herein.

(c) Changes in Internal Control Over Financial Reporting

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, whether any changes in our internal control over financial reporting that occurred during our last fiscal quarter have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on the evaluation we conducted, management has concluded that no such changes have occurred.

The Company s management has identified what it believes are the steps necessary to address the material weakness described above, as follows:

(1) Increasing training for the Company s current accounting personnel, hiring additional accounting personnel and engaging outside consultants with technical accounting expertise, as needed, and reorganizing the accounting department to ensure that accounting personnel have adequate experience, skills and knowledge relating to the accounting and internal audit functions assigned to them.

(2) Establishing additional and refining current policies and procedures to more effectively reconcile its accounting entries along with better documentation procedures to meet the standards established by COSO.

The Company expects to complete these remedial actions by the end of the second quarter of 2006.

(d) Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Ultra Petroleum Corp.:

We have audited management s assessment, included in the accompanying Management s Report on Internal Control Over Financial Reporting (Item 9A(b)), that Ultra Petroleum Corp. and subsidiaries (the Company) did not maintain effective internal control over financial reporting as of December 31, 2005, because of the effect of material weaknesses identified in management s assessment, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). 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. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of 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, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, 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.

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. The following material weaknesses have been identified and included in management s assessment as of December 31, 2005:

The Company did not maintain effective company level controls. Specifically, (i) certain of its accounting personnel in key roles did not possess an appropriate level of technical expertise, and (ii) the Company s monitoring of the internal audit function was not sufficient to provide management a basis to assess the quality of the Company s internal control performance over time. These deficiencies resulted in more than a remote likelihood that a material misstatement of the Company s annual or interim financial statements would not be prevented or detected.

The Company did not have adequate policies and procedures regarding supervisory review of account reconciliations and account and transaction analyses. This deficiency resulted in the following material errors in the Company s preliminary 2005 consolidated financial statements:

- misclassification of costs between proved and unproved oil and gas properties and understatement of depletion expense;
- improper reporting of value added taxes;
- understatement of asset retirement obligations;
- overstatement in tubular inventory;
- understatement of capitalized well cost accrued liabilities; and

overstatement of accounts receivable.

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The Company did not have adequate policies and procedures to ensure that accurate and reliable interim and annual consolidated financial statements were prepared and reviewed on a timely basis. Specifically, the Company did not have:

- sufficient personnel with the skills and experience in the application of U.S. generally accepted accounting principles; and

- policies and procedures regarding the preparation and management review of footnote disclosures accompanying the Company s financial statements.

As a result of these deficiencies, material errors were identified in the footnotes to the Company s preliminary 2005 consolidated financial statements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Ultra Petroleum Corp. and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of operations and retained earnings, shareholders equity and cash flows for each of the years in the three-year period ended December 31, 2005. The aforementioned material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the December 31, 2005 consolidated financial statements, and this report does not affect our report dated March 30, 2006, which expressed an unqualified opinion on those consolidated financial statements.

In our opinion, management s assessment that Ultra Petroleum Corp. and subsidiaries did not maintain effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, because of the effect of the material weaknesses described above on the achievement of the objectives of the control criteria, Ultra Petroleum Corp. and subsidiaries have not maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

/s/ KPMG LLP
Denver, Colorado
March 30, 2006

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

None.

Part III

Item 10. ***Directors and Executive Officers of the Registrant.***

The information required by this item will be included in the Company s definitive proxy statement, which will be filed not later than 120 days after December 31, 2005 and is incorporated herein by reference.

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 has been 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 will be included in the Company s definitive proxy statement, which will be filed not later than 120 days after December 31, 2005 and is incorporated herein by reference.

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, 2005 and is incorporated herein by reference.

Item 13. ***Certain Relationships and Related Transactions.***

The information required by this item will be included in the Company s definitive proxy statement, which will be filed not later than 120 days after December 31, 2005, and is incorporated herein by reference.

Item 14. ***Principal Accountants Fees and Services.***

The information required by this item will be included in the Company s definitive proxy statement, which will be filed not later than 120 days after December 31, 2005, and is incorporated herein by reference.

Part IV

Item 15. ***Exhibits, Financial Statement Schedules, and Reports on Form 8-K.***

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)
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)
10.1	Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of November 14, 2005 and effective as of November 18, 2005, by and among Ultra Resources, Inc., JPMorgan Chase Bank N.A., Union Bank of California N.A., Hibernia National Bank, Guaranty Bank FSB, Compass Bank, Bank of Scotland and Bank of America, N.A. (incorporated by reference from Exhibit 10.1 of the Company s Report on Form 8-K filed on November 23, 2005)
10.2	Third Amendment to Second Amended and Restated Credit Agreement dated May 5, 2005 among Ultra Resources, Inc., JPMorgan Chase Bank N.A., Union Bank of California N.A., Hibernia National Bank, Guaranty Bank FSB, Compass Bank, Bank of Scotland and Bank of America, N.A. (incorporated by reference from Exhibit 10.1 of the Company s Quarterly Report on Form 10-Q for the period ended June 30, 2005)

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Exhibit Number	Description
10.3	Second Amendment to Second Amended and Restated Credit Agreement dated November 1, 2004 among Ultra Resources, Inc., Bank One, NA, Union Bank of California, N.A., Hibernia National Bank, Guaranty Bank, FSB, Compass Bank, Bank of Scotland and Fleet National Bank. (incorporated by reference from Exhibit 10.1 of the Company s Report on Form 10-K for the year ended December 31, 2004)
10.4	First Amendment to Second Amended and Restated Credit Agreement dated August 10, 2004 among Ultra Resources, Inc., Bank One, NA, Union Bank of California, N.A., Hibernia National Bank, Guaranty Bank, FSB, Compass Bank, Bank of Scotland and Fleet National Bank. (incorporated by reference from Exhibit 10.2 of the Company s Report on Form 10-K for the year ended December 31, 2004)
10.5	Second Amended and Restated Credit Agreement dated June 9, 2004 among Ultra Resources, Inc., Bank One, NA, Union Bank of California, N.A., Hibernia National Bank, Guaranty Bank, FSB, Compass Bank, Bank of Scotland and Fleet National Bank (incorporated by reference from Exhibit 10.1 of the Company s Quarterly Report on Form 10-Q for the period ended June 30, 2004).
10.6	Precedent Agreement between Rockies Express Pipeline LLC and Ultra Resources, Inc. dated December 19, 2005 (incorporated by reference from Exhibit 10.1 of the Company s Report of Form 8-K filed on February 9, 2006)
10.7	Precedent Agreement between Rockies Express Pipeline LLC, Entrega Gas Pipeline LLC and Ultra Resources, Inc. dated December 19, 2005 (incorporated by reference from Exhibit 10.2 of the Company s Report on Form 8-K filed on February 9, 2006)
10.8	Ultra Petroleum Corp. 2005 Stock Incentive Plan (incorporated by reference from 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)
10.9	Ultra Petroleum Corp. 2000 Stock Incentive Plan (incorporated by reference from 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)
10.10	Ultra Petroleum Corp. 1998 Stock Option Plan (incorporated by reference from 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)
*10.11	Employment Agreement between Ultra Petroleum Corp. and Michael D. Watford dated February 1, 2004.
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 (incorporated by reference to Exhibit 21.1 to the Company s Annual Report on Form 10-K for the period ended December 31, 2001)
*23.1	Consent of Netherland, Sewell & Associates, Inc.
*23.2	Consent of Ryder Scott Company
*23.3	Consent of KPMG LLP
*31.1	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*32.1	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Filed herewith

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SIGNATURES

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

ULTRA PETROLEUM CORP.
By: /s/ Michael D. Watford

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

Date: March 31, 2006

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Michael D. Watford Michael D. Watford	Chairman of the Board, Chief Executive Officer, and President (principal executive officer)	March 31, 2006
/s/ Marshall D. Smith Marshall D. Smith	Chief Financial Officer (principal financial officer)	March 31, 2006
/s/ Kristen J. Marron Kristen J. Marron	Financial Reporting Manager (principal accounting officer)	March 31, 2006
/s/ W. Charles Helton W. Charles Helton	Director	March 31, 2006
/s/ James E. Nielson James E. Nielson	Director	March 31, 2006
/s/ Robert E. Rigney Robert E. Rigney	Director	March 31, 2006
/s/ James C. Roe James C. Roe	Director	March 31, 2006

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