ULTRA PETROLEUM CORP
Form 10-K
March 12, 2004

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

[X]	**Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
	For the Fiscal Year ended December 31, 2003.
[ ]	**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 Toronto Stock Exchange

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

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 [X] NO [ ]

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. [X]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). YES [X] NO [ ]

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was approximately $959,970,404 as of June 30, 2003 (based on the last reported sales price of $12.91 of such stock on the American Stock Exchange on such date).

Documents incorporated by reference: The definitive Proxy Statement for the 2004 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2003, is incorporated by reference in Part III of this Form 10-K.

TABLE OF CONTENTS

Table of Contents

TABLE OF CONTENTS

Table of Contents

PART I

Item 1. Description of 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 exploration and development of oil and gas properties.

As of December 31, 2003 Ultra owns interests in approximately 175,345 gross (97,990 net) acres in Wyoming covering approximately 300 square miles. The Company owns working interest in approximately 156 gross productive wells in this area and is operator of 51% of those wells. The Company s current domestic operations are principally focused on developing and expanding a tight gas sand project located in the Green River Basin in Southwest Wyoming. In 2003, the Company s Wyoming production was approximately 99% of the Company s total oil and natural gas production and all of the Company s proved reserves were in Wyoming. In 2003, capital expenditures in Wyoming comprised approximately 85% of the Company s total capital expenditures.

The Company acquired Pendaries Petroleum Ltd. on January 16, 2001. As a result of this acquisition, the Company became active in oil and gas exploration and development in Bohai Bay, China. The Company now holds an 18.182% working interest in Block 04/36 and a 15% working interest in Block 05/36 (jointly the Blocks). In 2003, the Company reported no production or reserves attributable to its China property. The Company spent approximately 15% of its 2003 capital budget in China. A wholly-owned subsidiary of Kerr-McGee Corporation is the operator of the Blocks. At the time of the acquisition, three oil discoveries had been made on the Blocks. Since the acquisition of Pendaries, six additional discoveries have been made on the Blocks, two of which were discoveries added in 2003.

The Company owns interests in approximately 15,841 gross (11,384 net) acres and interest in three productive wells in Texas. The Company also owns interest in 14,741 gross (14,087 net) acres in Pennsylvania.

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 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 plans to continue to identify, develop and explore the gas-rich acreage in the Green River Basin. The Green River Basin 2004 drilling program targets the upper Cretaceous Lance and Mesaverde sands in the area of the Pinedale Anticline and Jonah Fields. The Company plans to attempt to continue expanding the identified productive area through the drilling of step-out and exploration wells on its Green River Basin acreage as well as continue drilling deeper wells to test other potentially productive horizons. The Company is utilizing its 3-D seismic to map these deeper potentially productive intervals and to identify further extensions of the productive Lance fairway.

Bohai Bay, China

The Company plans to drill additional exploration and appraisal wells in 2004 on the Blocks and to continue development planning on the appraised discovery areas. The Company has discovered 9 oil fields on its two Bohai Bay Blocks. Of these 9 fields, 2 fields are under development with first production expected in the fourth quarter of 2004. Five of the fields are in various stages of development planning with tentative plans calling for all 5 fields to have an Overall Development Plan (ODP) submitted to the Chinese by year end 2004. If

Table of Contents

current development schedules are followed for these 5 fields, the Company should have a total of 7 fields on production by the end of 2006. Two of the 9 fields are still under appraisal.

Marketing and Pricing

The Company currently derives its revenue principally from the sale of natural gas. As a result, the Company s revenues are determined, to a large degree, by prevailing natural gas prices. The Company currently sells the majority of its natural gas on the open market at prevailing market prices, or pursuant to market price contracts in the Rocky Mountain region, more specifically in southwestern Wyoming. The market price for natural gas is dictated by supply and demand at these sales points, and the Company cannot accurately predict or control the price it receives for its natural gas. Moreover, market prices for natural gas vary significantly by region. For example, natural gas in the Rocky Mountain region, where the Company produces most of its natural gas, historically sells for less than natural gas in the Gulf Coast (Henry Hub), Mid Continent, Midwest and Northeast. Accordingly, the Company s income and cash flows will be affected by changes in natural gas prices and by regional pricing differentials. The Company will experience reduced cash flows and may experience operating losses when natural gas prices are low in the Rocky Mountain region. Under extreme circumstances, the Company s natural gas sales may not generate sufficient revenue to meet the Company s financial obligations and fund planned capital expenditures. Moreover, significant price decreases could negatively affect the Company s reserves by reducing the quantities of reserves that are recoverable on an economic basis, necessitating write-downs to reflect the realizable value of the reserves in the low price environment.

During the first half of 2003, the Company experienced significant pricing differentials in southwestern Wyoming relative to the Henry Hub (Louisiana) pricing reference point primarily due to production in the region exceeding interstate pipeline capacity to deliver gas to the consuming west and east. Without sufficient pipeline capacity to move the gas to markets, gas prices were bid down at the inlet of the interstate pipelines. Because of this large differential, the Company received prices significantly lower than those received by companies with production in other regions of the U.S.

In May of 2003, Kern River Pipeline which serves markets in California, Nevada and Utah expanded its system by over 900 MMcf/d or 100% to 1.73 Bcf/d. Additionally, Northwest Pipeline, which serves the Pacific Northwest, expanded its system by 175 MMcf/d in late 2003. These expansions moderated the price differentials between southwestern Wyoming and the Henry Hub (Louisiana) pricing reference point. However, there can be no assurance that the expansions will eliminate large differentials in the future or that future expansions will be made to accommodate the projected growth in production from the region.

The Company expects to begin production from the first two fields (CFD 11-1/11-2) on Block 04/36 Bohai Bay, China in the fourth quarter of 2004. At that time, the price of crude oil, in particular oil prices in East Asia, will become important to the Company s revenues. As of February 27, 2004, the Company was still negotiating a Memorandum of Understanding (MOU) relating to the valuation of marketing of crude oil from the CFD 11-1/11-2 fields. It is anticipated that the oil from the CFD 11-1/11-2 fields will be priced based on (Indonesian) Duri crude postings with adjustments for quality and location. The quality of crude blend from CFD 11-1/11-2 is currently not known with any degree of certainty because of variations in crude quality from the multiple productive reservoirs. The Company believes it will be successful in reaching agreement on the MOU. The Company will review opportunities to utilize forward sales and financial derivations, if any, to reduce the volatility of the prices it will receive for its CFD 11-1/11-2 crude oil.

The Company uses forward sales and financial derivations to reduce the volatility of the prices it receives for the sale of its natural gas production. See Item 7A for more details.

Competition

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.

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

Table of Contents

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 process of reviews is currently undergoing changes to satisfy the Federal Advisory Committee Act. The Company cannot predict if or how these changes may affect permitting, development and compliance under the 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 year end, the Company had approximately 85 permits to drill wells on Company operated federal leases in the Pinedale Anticline area.

To date, the Company has expended significant resources in order to satisfy applicable environmental laws and regulations in the Pinedale Anticline area and other areas of operation under the jurisdiction of the BLM. The Company s future costs of complying with these regulations may continue to be 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 drilling density 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 environmental impacts of developing the field on 40-acre well density rather than the 80-acre density that was approved in the initial EIS in 1998. The EA was completed in June 2000. With the approval of this subsequent EA, the Company was permitted to infill drill on 40-acre well density the 2,160 gross (1,322 net) acres owned in the field. Prior to this approval, the Company had drilled 21 gross (7.7 net) wells in the field. Since the approval of 40-acre spacing, the Company drilled an additional 22 gross (14.0 net) wells during 2000 and 2001. All 43 of the wells drilled by the Company in Jonah Field have been productive. Other operators in the Jonah Field have obtained approval for down-spacing portions of the Jonah Field to 20-acre and 10-acre spacing to test the feasibility of developing the field at tighter spacing than the currently approved 40-acre spacing. The BLM is currently conducting a new EIS covering the Jonah Field in anticipation of down-spacing the entire field at some point in the near future. The Company cannot predict when this EIS will be finalized.

During 2003 Ultra and other operators on the Pinedale Anticline received approval from the Wyoming Oil & Gas Conservation Commission to drill increased density pilots in several areas of the Pinedale Anticline Field to test the feasibility of developing the field at higher well density than the currently allowed 16 wells per section (40-acre spacing).

In September 2002, the Company received the Oil & 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 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 gas well may be shut-in because of a lack of an available 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 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 gas by pipelines are regulated by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Acts, 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 gas industry by making gas transportation more accessible to gas buyers and sellers on an open-access, non-discriminatory basis.

The Company s sales of oil are also affected by the availability, terms and costs of transportation. The rates, terms, and conditions applicable to the interstate transportation of oil by pipelines are regulated by the FERC under the Interstate Commerce Act. The FERC has implemented a simplified and generally applicable ratemaking methodology for interstate oil pipelines to fulfill the requirements of Title VIII of the Energy Policy Act of 1992 comprised of an indexing system to establish ceilings on interstate oil pipeline rates. The FERC has announced several important transportation-related policy statements and rule changes, including a statement of policy and final rule issued February 25, 2000 concerning alternatives to its traditional cost-of-service rate-making methodology to establish the rates interstate pipelines may charge for their 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.

In the event the Company conducts operations on federal or state oil and gas leases, such operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes and royalty and related valuation requirements. In addition, certain of such operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the BLM or Minerals Management Service (MMS) or other appropriate federal or state 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 to 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 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 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 nonhazardous 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 (PRPs), 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 Substance. 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.

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.

Table of Contents

Clean Water Act. The Clean Water Act (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 Act 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.

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 February 27, 2004, the Company had 31 full time employees, including officers.

Item 2. Description of Property.

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 65,528 gross (36,494 net) acres currently held by production. 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. The production period of any oil and gas field in a block is a period of 15 consecutive years commencing on the date of commencement of commercial production from the field, unless extended.

Green River Basin, Wyoming

As of December 31, 2003, the Company owned developed oil and gas leases totaling 7,290 gross (3,157 net) acres in the Green River Basin of Sublette County, Wyoming which represents 91% of the Company s total domestic developed gross acreage. The Company owned undeveloped oil and gas leases totaling 168,055 gross (94,833 net) acres in the Green River Basin of Sublette County, Wyoming which represents 85% of the Company s total domestic undeveloped gross acreage. The Company s acreage in the Green River Basin is primarily covering 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 $130,000 for the fiscal year ended December 31, 2003. The primary target on the Company s Wyoming acreage is the tight gas sands of the upper Cretaceous Lance formation.

Table of Contents

Exploratory Wells. During the year-ended December 31, 2003, the Company participated in the drilling of a total of 25 gross (10.18 net) exploratory wells on the Green River Basin properties. Of these, only 1 gross (.32 net) was a dry hole. This one well had to be junked and abandoned due to mechanical problems. At year end there were 9 gross (4.66 net) additional exploratory wells that were either still drilling or had drilling operations suspended for winter.

Development Wells. The Company participated in the drilling of 24 gross (6.88 net) successful development wells in the Pinedale Field area. At year end there were 5 gross (1.95 net) additional development wells that were either still drilling or had drilling operations suspended for winter. For purposes of classification of development wells, the Company is using the definition of wells identified as proven undeveloped locations by the 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 Production Sharing Contract (PSC) covering this block became effective October 1, 1994. Negotiations with the Chinese government in 2003 resulted in an extension of the third exploration term to September 2005. As the contract now stands, the exploration period will end at the end of September 2005. Barring an extension, at that time all acreage not under appraisal, development or production must be relinquished. The Company holds an 18.182% working interest in this block which is 454,000 gross (82,546 net) acres, or 66% of the Company s total gross international acreage.

Block 05/36: The PSC covering this block became effective March 1, 1996. Negotiations with the Chinese government in 2003 resulted in an extension of the third exploration term to the end of February 2005. The third (and final) exploration term will now continue through the end of February 2005 when, barring an extension, all acreage not under appraisal, development or production must be relinquished. The Company holds a 15% working interest in this block which is 233,300 gross (34,995 net) acres, or 34% of the Company s total gross international acreage.

Exploration / Appraisal Activity. In 2003, utilizing 3-D seismic data, the Company participated in drilling 4.0 gross (0.66 net) exploratory wells and 6.0 gross (1.03 net) appraisal wells on the Blocks. The exploratory drilling resulted in 2 new discoveries on the Blocks. Four appraisal wells were successful. The primary target formations on the Blocks are the Tertiary Minghuazhen, Guantuao and Dongying formations.

Development Activity. An ODP for two of the fields on Block 04/36 (CFD 11-1/11-2) was approved by CNOOC in September 2002 and CNOOC has elected to participate for its 51% working interest in the development of these fields. The Chinese government gave its approval in June 2003. A MOU for marketing and valuation of the CFD 11-1/11-2 crude oil, a Lifting Agreement for the CFD 11-1/11-2 oil fields and a Field Terminal Information and Regulation Agreement are expected to be signed in March 2004 thus clearing the way for full commerciality of the two fields. Construction started on the offshore production platforms and a Floating Production Storage and Offloading (FPSO) vessel, which will be leased from CNOOC under an operating lease for these fields. The platform jackets were installed offshore in June 2003 and development well drilling started in the fourth quarter 2003. The FPSO contract calls for the vessel to be on location ready to receive oil in the third quarter of 2004 with oil production starting soon thereafter.

On October 16, 2003 a 15 year contract which provides for extensions for up to an additional 10 years was signed by the Operator to lease an FPSO. The Company ratified the contract for its net share which is 8.92%. The FPSO contract specifies a 110,000-150,000 dead weight tons (DWT) double-hull FPSO with a 900,000-1,100,000 barrels storage capacity, with Single Point Mooring (SPM) and a processing plant capable of processing 60,000 barrels oil/day (expandable to 80,000 barrels oil/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 14,741 gross (14,087 net) acres in Pennsylvania, which represents 7% of the Company s total domestic undeveloped gross acreage.

Texas

The Company operates one gross (0.66 net) well and owns working interests in an additional two gross (0.22 net) wells in Texas and owns 720 gross (382 net) developed acres which represents 9% of the Company s total developed gross acreage. In 2003, the Company leased 15,121 gross (11,002 net) acres in Texas which represents 8% of the Company s total domestic undeveloped gross acreage.

Oil and Gas Reserves

The following table sets forth the Company s quantities of proved reserves, for the years-ended December 31, 2003, 2002 and 2001 as estimated by independent petroleum engineers Netherland, Sewell & Associates, Inc. All of the Company s proved oil and gas reserves are located in the Green River Basin, Wyoming. The table summarizes the Company s proved reserves, the estimated future net revenues from these reserves and the standardized measure of discounted future net cash flows attributable thereto at December 31, 2003, 2002 and 2001. 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, 2007. Proved undeveloped reserves represent 64.9% of total proved reserves.

	December 31, (in thousands)		
	2003	2002	2001
Proved Undeveloped Reserves			
Natural gas (MMcf)	664,295	444,513	273,433
Oil (MBbl)	5,314	3,556	2,187
Proved Developed Reserves			
Natural gas (MMcf)	359,072	222,608	150,397
Oil (MBbl)	3,028	2,003	1,295
Total Proved Reserves (MMcfe)	1,073,419	700,474	444,727
Estimated future net cash flows, before income tax	$4,456,478	$1,308,595	$531,676
Standardized measure of discounted future net cash flows	$1,784,314	$ 473,528	$182,460
Standardized measure of discounted future net cash flows, after income tax	$1,135,513	$ 316,965	$119,259

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 Ultra s sale of oil and natural gas for the periods indicated.

	Year Ended December 31,		
	2003	2002	2001
Production			
Natural gas (Mcf)	27,621,759	16,495,751	11,500,446
Oil (Bbl)	211,591	151,215	116,413
Total (Mcfe)	28,891,305	17,403,041	12,198,924
Revenues			
Gas sales	$114,840,558	$38,502,971	$38,204,298
Oil sales	6,740,539	3,839,421	2,996,955
Total Revenues	121,581,097	42,342,392	41,201,253
Lease Operating Expenses			
Production costs*	3,627,639	2,356,986	1,439,026
Severance/production taxes	13,767,668	4,116,012	4,425,345

Gathering	7,828,372	4,937,870	3,158,901
Total Lease Operating Expenses	$ 25,223,679	$11,410,868	$ 9,023,271

Table of Contents

	Year Ended December 31,		
	2003	2002	2001
Realized Prices			
Natural gas (Mcf)	$ 4.16	$ 2.33	$ 3.32
Oil (Bbl)	$31.86	$25.39	$25.74
Operating Costs per Mcfe			
Production costs	$ 0.13	$ 0.14	$ 0.12
Severance/production taxes	$ 0.48	$ 0.24	$ 0.36
Gathering	$ 0.27	$ 0.28	$ 0.26
Total Operating Costs per Mcfe	$ 0.88	$ 0.66	$ 0.74

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

Productive Wells

As of December 31, 2003, the Company s total gross and net wells were as follows:

Productive Wells*	Gross Wells	Net Wells
Natural Gas and Condensate	159	69.58

* 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, 2003, 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	7,290	3,157	168,055	94,833
Pennsylvania			14,741	14,087
Texas	720	382	15,121	11,002
All States	8,010	3,539	197,917	119,922

As of December 31, 2003, 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	0	0	454,000	82,546
Block 05/36	0	0	233,300	34,995
Total Bohai Acreage	0	0	687,300	117,541

Table of Contents

Drilling Activities

For each of the three fiscal years ended December 31, 2003, 2002 and 2001, the number of gross and net wells drilled by the Company was as follows:

Wyoming Green River Basin

	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	24.00	6.88	16.00	5.50	9.00	5.52
Dry	0.00	0.00	0.00	0.00	0.00	0.00
Total	24.00	6.88	16.00	5.50	9.00	5.52

At year end there were 5 gross (1.95 net) additional development wells that were either drilling or had drilling operations suspended over the winter.

	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	24.00	9.86	10.00	5.22	22.00	8.67
Dry	1.00	0.32	0.00	0.00	1.00	0.42
Total	25.00	10.18	10.00	5.22	23.00	9.09

At year end there were 9 gross (4.66 net) additional exploratory wells that were either drilling or had drilling operations suspended over the winter.

Texas

	2003		2002		2001	
	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	0.15	0.00	0.00
Total	0.00	0.00	1.00	0.15	0.00	0.00

China Bohai Bay

	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net

Exploratory Wells						
Productive and Successful Appraisal*	6.00	1.03	4.00	0.70	14.00	2.35
Dry	4.00	0.66	1.00	0.18	1.00	0.18
Total	10.00	1.69	5.00	0.88	15.00	2.53

* 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, 2003.

Table of Contents

PART II

Item 5. Market for Registrant s Common Stock and Related Stockholder Matters.

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 the Toronto Stock Exchange (TSE) since September 30, 1998 under the symbol UP . The following table sets forth the high and low closing sales prices on the AMEX and TSE for 2003, 2002 and 2001 as reported by each exchange, respectively.

AMERICAN STOCK EXCHANGE (US$)

2003	High	Low
First Quarter	$10.24	$ 8.60
Second Quarter	$12.91	$ 8.45
Third Quarter	$14.80	$11.50
Fourth Quarter	$25.45	$14.05
2002	High	Low
First Quarter	$ 8.17	$ 5.71
Second Quarter	$ 9.22	$ 7.50
Third Quarter	$ 8.59	$ 5.94
Fourth Quarter	$ 9.99	$ 7.90
2001	High	Low
First Quarter (beginning 1/17/01)	$ 5.50	$ 3.00
Second Quarter	$ 7.34	$ 4.34
Third Quarter	$ 5.92	$ 3.54
Fourth Quarter	$ 6.41	$ 4.00

TORONTO STOCK EXCHANGE (CDN$)

2003	High	Low
First Quarter	$15.66	$12.61
Second Quarter	$17.41	$12.42
Third Quarter	$20.18	$15.90
Fourth Quarter	$33.36	$18.94
2002	High	Low
First Quarter	$13.10	$ 9.25
Second Quarter	$14.50	$11.34
Third Quarter	$13.51	$ 9.35
Fourth Quarter	$15.62	$12.47
2001	High	Low
First Quarter	$ 8.70	$ 3.90
Second Quarter	$10.95	$ 6.76
Third Quarter	$ 9.00	$ 5.65
Fourth Quarter	$10.05	$ 6.30

On February 27, 2004, the last reported sale price of the common stock on the AMEX was $29.16 per share. As of February 27, 2004 there were approximately 457 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 prohibits payment of dividends on its common stock.

Item 6. Selected Financial Data.

The selected consolidated financial information presented below for the years ended December 31, 2003, 2002, 2001, 2000, the six months ended December 31, 1999 and the year ended June 30, 1999 is derived from the Consolidated Financial Statements of the Company. Effective with the period ended December 31, 1999, the Company began utilizing a December 31 year-end.

	Year Ended December 31,				Six Months Ended	Year Ended
	2003	2002	2001	2000	December 1999	June 1999
	(in thousands, except per share data)					
Statement of Operations Data						
Revenues:						
Natural gas sales	$114,841	$38,503	$38,204	$19,399	$4,352	$6,352
Oil sales	6,740	3,839	2,997	1,604	434	670
Interest and other	37	23	393	171	18	287
Total revenues	121,618	42,365	41,594	21,174	4,804	7,309

Table of Contents

	Year Ended December 31, 2003	2002	2001	2000	Six Months Ended December 1999	Year Ended June 1999
	(in thousands, except per share data)					
Expenses:						
Production expenses and taxes	25,224	11,411	9,023	4,241	1,329	2,571
Depreciation, depletion and amortization	16,216	9,712	6,687	3,163	1,186	1,794
General and administrative	5,733	4,199	3,894	2,828	1,668	5,861
Stock compensation	1,018	1,211	337	250		
Interest	2,851	2,691	1,687	802	344	577
Ceiling test write-down						3,417
Bad debt expense (recovery)					(35)	2,019
Lawsuit settlement					1,876	
Total expenses	51,042	29,224	21,628	11,284	6,368	16,239
Income from continuing operations before income taxes	70,576	13,141	19,966	9,890	(1,564)	(8,930)
Income tax provision deferred	25,254	5,059	2,087			
Net income	$45,323	$ 8,082	$17,879	$ 9,890	$(1,564)	$ (8,930)
Basic income per common share	$ 0.61	$ 0.11	$ 0.25	$ 0.17	$ (0.03)	$ (0.16)
Diluted income per common share	$ 0.58	$ 0.10	$ 0.24	$ 0.17	$ (0.03)	$ (0.16)

	Year Ended December 31, 2003	2002	2001	2000	Six Months Ended December 1999	Year Ended June 1999
	(in thousands)					
Statement of Cash Flows Data						
Net cash provided by (used in):						
Operating activities	$ 76,461	$ 21,490	$ 34,136	$ 9,046	$ 674	$ 1,913
Investing activities	(90,033)	(64,360)	(59,862)	(24,541)	(1,624)	(1,017)
Financing activities	13,988	42,908	25,961	16,236	569	(6,010)

	As of December 31, 2003	2002	2001	2000	1999
Balance Sheet Data					
Cash and cash equivalents	$ 1,834	$ 1,418	$ 1,379	$ 1,144	$ 402
Working capital (deficit)	(22,057)	(4,415)	(6,635)	241	195
Oil and gas properties	307,864	207,362	155,221	59,729	33,773
Total assets	345,770	221,874	167,583	73,177	38,063
Total long-term debt	104,120	89,859	48,885	24,731	8,767
Deferred income taxes	33,446	10,033	4,974		
Total stockholders equity	149,453	104,067	95,320	35,694	25,632

Critical Accounting Policies

The discussion and analysis of the Company s financial condition and results of operations is based upon consolidated financial statements, which have been prepared in accordance with U.S. GAAP. In addition, application of generally accepted accounting principles requires the use of estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements as well as the revenues and expenses reported during the period. Changes in these estimates, judgments and assumptions will occur as a result of future events, and, accordingly, actual results could differ from amounts estimated.

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.

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 by additional data. Revisions are necessary due to changes in assumptions based on, among other things, reservoir performance, prices, economic conditions and governmental restrictions. Decreases in prices, for example, may cause a reduction in some proved reserves due to the production of such resources becoming uneconomic.

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. Capitalized costs applicable to each full cost center are depleted using the units of production method based on conversion to a common unit of measure using one barrel of oil as an equivalent to six thousand cubic feet of natural gas. A reserve is also provided for estimated future development costs related to proved reserves and for estimated future costs of site restoration, dismantlement and abandonment as a component of depletion expense. 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 NGLs 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.

Oil and gas properties include costs that are excluded from capitalized costs being amortized. These amounts represent costs of investments in unproved properties, pending the determination of the existence of proved reserves. 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 quarterly to determine if impairment has occurred. Any impairment is transferred to the costs to be amortized. Costs excluded for oil and gas properties are generally classified and evaluated as significant or individually insignificant properties.

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.

Companies that use the full cost method of accounting for oil and gas exploration and development activities are required to perform a ceiling test 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 on a country-by- country basis. The test determines a limit, or ceiling, on the book value of oil and gas properties. That limit is basically the after tax present value of the future net cash flows from proved crude oil and natural gas reserves. This ceiling is compared to the net book value of the oil and gas properties reduced by any related deferred income tax liability. If the net book value reduced by the related deferred income taxes exceeds the ceiling, an impairment or non-cash write down is required. A ceiling test impairment can give the Company a significant loss for a particular period; however, future depletion, depreciation and amoritization expense would be reduced. The following is a summary of major issues related to the Company s ceiling test calculation.

The Company did not have any writedowns related to the full cost ceiling limitation in 2003, 2002 or 2001. As of December 31, 2003, the ceiling limitation exceeded the carrying value of the Company s oil and gas properties by approximately $900 million in the U.S. The Company s China properties have not yet been subject to a ceiling test, as there have not been any proved reserves identified to date. Estimates of discounted future net cash flows at December 31, 2003 were based on average natural gas prices of approximately $5.59 per MCF in the U.S. and on average liquids prices of approximately $31.01 per barrel in the U.S. A reduction in oil and gas prices and/or estimated quantities of oil and gas reserves would reduce the ceiling limitation in the U.S. and could result in a ceiling test writedown.

In China, the existence of proved reserves has not yet been confirmed, therefore, leasehold costs, seismic costs and other costs incurred during the exploration phase remain capitalized as unproved property costs until proved reserves have been established or until exploration activities cease. If exploration activities result in the establishment of proved reserves as the Company expects, amounts are reclassified as proved properties and become subject to depreciation, depletion and amortization and the application of the ceiling test. If exploration and appraisal efforts are unsuccessful in establishing proved reserves and exploration activities cease, the amounts accumulated as unproved costs are charged against earnings as impairments. As of December 31, 2003, costs related to these international projects of approximately $81.0 million were not being depleted pending confirmation of the existence of proved reserves.

Changes in estimates of reserves, future development costs or future abandonment costs are accounted for prospectively in the depletion calculations.

Entitlements Method of Accounting for Oil and Gas Sales. 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. At December 31, 2003, the Company had taken approximately 264 MMcf more than its entitled share of production. The estimated value of this imbalance of approximately $1.3 million was recorded as a long-term liability under the Notes Payable category on the Balance Sheet.

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 bases (temporary differences). Future income tax assets and liabilities are measured using the tax rates expected to be in effect when the temporary differences are likely to reverse. The effect on future income tax assets and liabilities of a change in tax rates is included in operations in the period in which the change is enacted. The amount of future income tax assets recognized is limited to the amount of the benefit that is more likely than not to be realized.

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. In order to fully realize its U.S. net deferred tax asset at December 31, 2003, the Company will need to generate future taxable income prior to the expiration of the net operating loss carryforwards in 2004 to 2023. Based upon the level of historical taxable income and projections for future taxable income over the periods, which the deferred tax assets are deductible, management believes it is more likely than not the Company will realize the benefits of these deductible differences, net of the existing valuation allowances at December 31, 2003. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carryforward periods are reduced.

Commodity Derivative Instruments and Hedging Activities. The Company periodically enters into commodity derivative contracts and fixed-price physical contracts to manage its exposure to oil and natural gas price volatility. The Company primarily utilizes price swaps, which are generally placed with major financial institutions or with counter-parties of high credit quality that it believes are minimal credit risks. The oil and natural gas reference prices of these commodity derivatives contracts are based upon crude oil and natural gas futures, which have a high degree of historical correlation with actual prices the Company receives. Under SFAS No. 133 all derivative instruments are recorded on the balance sheet at fair value. Changes in the derivative s fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) to the extent the hedge is effective. For qualifying fair value hedges, the gain or loss on the derivative is offset by related results of the hedged item in the income statement. Gains and losses on hedging instruments included in accumulated other comprehensive income (loss) are reclassified to oil and natural gas sales revenue in the period that the related production is delivered. Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at market value in the consolidated balance sheet, and the associated unrealized gains and losses are recorded as current expense or income in the consolidated statement of operations. The Company currently does not have any derivative contracts in place that do not qualify as a cash flow hedge.

Legal, Environmental and Other Contingencies. A provision for legal, environmental and other contingencies is charged to expense when the loss is probably 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.

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 its revenue, earnings and cash from the production and sales of natural gas and oil from its property in southwestern Wyoming. The price of natural gas in the southwest Wyoming region is a critical factor to the Company s business. The price of gas in southwest Wyoming historically has been volatile. The average annual realizations for the period 2001-2003 have ranged from $2.33 to $4.16 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 derivative and forward sales contracts for gas in southwest Wyoming (see Item 7A). The Company also has oil properties offshore Bohai Bay, China which are expected to begin production in late 2004. At that time, the price of oil in east Asia would become critical to the Company.

The Company has grown its natural gas and oil production significantly over the past three 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 oilfields in China. The Company has experienced significant production growth over the last three years and expects this growth to continue in 2004:

	2001	2002	2003	Forecast 2004
Production Bcfe	12.2	17.4	28.9	40.0

The anticipated 2004 production growth of 40 Bcfe is expected to be achieved by drilling wells in Wyoming. The Company also expects to maintain its cost structure in Wyoming on a unit of production basis during 2004 as follows:

Table of Contents

Cost Item	$/Mcfe
Lease Operating Expense	$0.15
Gathering Expense	$0.30
DD&A	$0.57

The Company will provide further guidance on expected production and costs related to the China project at such time as production and costs become more certain.

The Company uses the full cost method of accounting for oil and gas operations whereby all costs associated with the exploration for and development of oil and gas reserves are capitalized to the Company s cost centers. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells and overhead charges directly related to acquisition, exploration and development activities. 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, the amounts 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.

Results of Operations Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Oil and gas revenues increased to $121.6 million for the year ended December 31, 2003 from $42.3 million for the same period in 2002. This increase was attributable to an increase in both the Company s production and prices received for that production. During this period the Company s production increased to 27.6 Bcf of gas and 211.6 thousand barrels of condensate, up from 16.5 Bcf of gas and 151.2 thousand barrels of condensate for the same period in 2002. This 66% increase on a Mcfe basis was attributable to the Company s successful drilling activities during 2003 and 2002. During the year ended December 31, 2003 the average product prices were $4.16 per Mcf and $31.86 per barrel, compared to $2.33 per Mcf and $25.39 per barrel for the same period in 2002.

Production costs increased to $3.6 million in 2003 from $2.4 million in 2002. On a unit of production basis, costs were $0.13 per Mcfe in 2003, as compared to $0.14 per Mcfe in 2002 primarily due to increased production. Production taxes in 2003 were $13.8 million, compared to $4.1 million in 2002, or $0.48 per Mcfe in 2003, compared to $0.24 per Mcfe in 2002. 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 for the period increased to $7.8 million in 2003 from $4.9 million in 2002, attributable to higher production volumes.

Depletion, depreciation and amortization (DD&A) expenses increased to $16.2 million during the year ended December 31, 2003 from $9.7 million for the same period in 2002, also attributable to increased production volumes. On a unit basis, DD&A remained flat at $0.56 per Mcfe in 2003.

Interest expense for the period increased to $2.8 million in 2003 from $2.7 million in 2002. This increase was attributable to the increase in borrowing under the senior credit facility which was partially offset by lower interest rates.

Deferred income tax expense for the period increased to $25.3 million in 2003 from $5.1 million in 2002. This increase was attributable to an increase in net income from continuing operations. Deferred income taxes were booked at the rate of 35.8% as compared to a rate of 38.5% in 2002. The Company was not liable for current payment of any material income taxes for the period ending December 31, 2003.

At year-end 2003, the Company had an inventory account of $13.6 million as compared to $0.0 at year-end 2002. This inventory is tubular materials related to the purchase of pipe for the Company s operated drilling program in Wyoming. In previous years the Company did not purchase tubular materials prior to when they would be used.

Results of Operations Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Oil and gas revenues increased to $42.3 million for the year ended December 31, 2002 from $41.2 million for the same period in 2001. This increase was attributable to an increase in the Company s production offsetting a decline in the price received for that production. During this period the Company s production increased to 16.5 Bcf of gas and 151.2 thousand barrels of condensate, up from 11.5 Bcf of gas and 116.4

thousand barrels of condensate for the same period in 2001. This 43% increase on a Mcfe basis was attributable to the Company s successful drilling activities during 2001 and 2002. During the year ended December 31, 2002, the average product prices were $2.33 per Mcf and $25.39 per barrel, compared to $3.32 per Mcf and $25.74 per barrel for the same period in 2001.

Production costs increased to $2.4 million in 2002 from $1.4 million in 2001. On a unit of production basis, costs were $0.135 per Mcfe in 2002, as compared to $0.118 per Mcfe in 2001. Production taxes in 2002 were $4.1 million, compared to $4.4 million in 2001, or $0.237 per Mcfe in 2002, compared to $0.363 per Mcfe in 2001. Production taxes are calculated based on a percentage of revenue from production. Therefore, lower prices received reduced the cost on a per unit basis. Gathering fees for the period increased to $4.9 million in 2002 from $3.2 million in 2001, attributable to higher production volumes and slightly higher gathering rates related to capacity constraints.

Depletion, depreciation and amortization (DD&A) expenses increased to $9.7 million during the year ended December 31, 2002 from $6.7 million for the same period in 2001. On a unit basis, DD&A increased slightly to $0.558 per Mcfe in 2002, from $0.548 per Mcfe in 2001 primarily as a result of increases in future development costs relative to increases in the proved reserves used to calculate depletion of the full cost pool.

General and administrative expenses increased to $4.2 million during the year ended December 31, 2002 from $3.9 million for the same period in 2001. The increase was primarily attributable to increases in personnel and overhead expenses arising from the increases in activity on the Wyoming properties.

Stock compensation expense increased to $1.2 million in 2002 from $0.3 million in 2001. This increase is attributable to the increased number of shares granted and the share price at the time the stock was granted.

Interest expense for the period increased to $2.7 million in 2002 from $1.7 million in 2001. This increase was attributable to the increase in borrowing under the senior credit facility.

Deferred income tax expense for the period increased to $5.1 million in 2002 from $2.1 million in 2001. This increase was attributable to an increase in the effective tax rate due to the absence of book tax losses available to offset book taxable income as compared to 2001. The Company was not liable for current payment of any material income taxes for the period ending December 31, 2002.

Liquidity and Capital Resources

In the year ended December 31, 2003, the Company primarily relied on its cash provided by operations of $76.4 million and borrowings under its existing senior credit facility of ($13 million net) to finance its capital expenditures. The Company participated in the drilling of 63 gross (23.99 net) wells in Wyoming of which 48 gross (17.06 net) were successfully drilled and completed, one gross (0.32 net) was abandoned due to hole condition and 14 gross (6.61 net) were either still drilling at year-end or had been suspended due to lease stipulations that prohibit winter drilling. The Company participated in 10 gross (1.69 net) wells in the China blocks.

For the twelve-month period ending December 31, 2003, net capital expenditures were $115.8 million, of which $26.5 million was accrued at year end for a net cash expenditure of $90 million. At December 31, 2003, the Company reported a cash position of $1.8 million compared to $1.4 million at December 31, 2002. Working capital at December 31, 2003 was $(22.0) million as compared to $(4.4) million at December 31, 2002. As of December 31, 2003, the Company had incurred bank indebtedness of $99.0 million and other long-term debt of $7.1 million which was comprised of items payable in more than one year.

Cash provided by operating activities, along with the availability under the senior credit facility, are projected to be sufficient to fund the Company s budgeted capital expenditures for 2004, which are currently projected to be $190.0 million. Of the $190.0 million budget, the Company plans to spend approximately $162.0 million of its 2004 budget in Wyoming and approximately $25.0 million in China, with the balance allocated to evaluating other areas. With the $162.0 million for Wyoming, the Company plans to drill or participate in an estimated 80 gross wells in 2004, of which approximately 35% will be for exploration wells and the remaining will be for development wells. Of the $25.0 million budgeted for China, approximately 30% will be for exploratory/appraisal activity and the balance will be for development activity. The Company does not have a budget for acquisitions.

Table of Contents

As of December 12, 2003, the revolving senior credit facility provides for a $250.0 million revolving credit line with a current borrowing base of $200.0 million. The credit facility matures on March 1, 2006. The notes bear interest at either Bank One s prime rate plus a margin of one-half of one percent (0.50%) to one and one-quarter percent (1.25%) based on the percentage of available credit drawn or at LIBOR plus a margin of one and one-half percent (1.50%) to two and one-quarter percent (2.25%) based on the percentage of available credit drawn. An average annual commitment fee of 0.375% is charged quarterly for any unused portion of the credit line. The borrowing base is subject to periodic (at least semi-annual) review and re-determination by the banks and may be increased or decreased depending on a number of factors, including the Company s proved reserves and the bank s forecast of future oil and gas prices. 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, the Company s subsidiary that owns the Chinese interests. In the event of a default under the covenants, the Company may not be able to access funds otherwise available under the facility and may, in certain circumstances, be required to repay the credit facilities. The notes are collateralized by a majority of the Company s proved domestic oil and gas properties. At December 31, 2003 the Company had $99.0 million of outstanding borrowings under this credit facility, with a current average interest rate of approximately 2.8%.Kristen to confirm The Company was in compliance with all loan covenants at December 31, 2003.

During the year ended December 31, 2003, net cash provided by operating activities was $76.5 million as compared to $21.5 million for the year ended December 31, 2002 and $34.1 million for the year ended December 31, 2001. The increase in cash provided by operating activities was attributable to the increase in earnings, which were driven primarily by higher production and gas prices received.

During the year ended December 31, 2003, cash used in investing activities was $90.0 million as compared to $64.4 million for the year ended December 31, 2002 and $59.9 million for the year ended December 31, 2001. The change is primarily attributable to increased drilling and completion activity in Wyoming.

During the year ended December 31, 2003, cash provided by financing activities was $14.0 million as compared to $42.9 million for the year ended December 31, 2002 and $26.0 million for the year ended December 31, 2001. The change is primarily attributable to a reduced level of borrowings under the senior credit facility ($13.0 million in 2003 as compared to $43.0 million during 2002 and $25.4 million during 2001).

Although the Company projects that the cash provided by operating activities and the availability under the senior credit facility will be sufficient to fund the Company s budgeted capital expenditures for 2004, future cash provided by operating activities and continued availability of financing are subject to a number of uncertainties beyond the Company s control such as the price of gas and oil, production rates, continued results of the Company s drilling program and the general condition of the capital and credit markets for oil and gas companies. There can be no assurances that adequate funding will be available to execute the Company s planned future capital program.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2003:

	2003	2004-2005	2006-2007	After 2007	Total
Capital expenditures for operations in progress	$	$12,384,391	$	$	$ 12,384,391
Long-term debt			99,000,000		99,000,000

Operating leases	291,015	198,030	132,020		621,065
Office space lease	73,458	497,519	455,084	73,458	1,099,519
Total contractual obligations	$364,473	$13,079,940	$99,587,104	$73,458	$113,104,975

As of December 31, 2003 the Company had committed to drilling obligations in progress that will continue into 2004.

The Company s senior credit facility with its group of banks matures on March 1, 2006. Unless the facility is extended or a new facility put into place, the full amount drawn under the facility would become due and payable at that time. The Company believes that it will be able to extend or renew the facility or one substantially similar to the existing facility prior to March 1, 2006.

On October 16, 2003 a 15 year contract, which provides for up to an additional 10 years, was signed by the Operator to lease an FPSO. The Company ratified the contract for its net share which is 8.92%. 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. Lease cancellation on the part of the Company prior to the FPSO starting offshore operations would commit the Company to its 8.92% share of up to $50 million in cancellation fees. The lease cancellation fee, after commencement of offshore operations, would be based on a sliding time-scale (cancellation fee decreases with time) with 8.92% of $50 million being the maximum cancellation fee. 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.

In May of 2003 the Company amended its prior office lease in Englewood, Colorado, which it has committed to through June 2008. The Company s total commitment of this lease is $734,578. 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 commitment of $364,941. The total commitment for both offices is $1,099,519.

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 holding expenses will be. In 2003, total holding costs for all of the Company s leases not held by production were $190,000.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company s major market risk exposure is in the pricing applicable to its gas and oil production. Realized pricing is currently primarily driven by the prevailing price for the Company s Wyoming natural gas production. Historically, prices received for gas production have been volatile and unpredictable. Pricing volatility is expected to continue. Gas price realizations ranged from a monthly low of $3.35 per Mcf to a monthly high of $4.94 per Mcf during 2003. Realized natural gas prices are derived from the financial statements, include the effects of hedging and gas balancing.

The Company uses 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 Company recognizes all derivative instruments as assets or liabilities in 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 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. At December 31, 2003 the Company had a current derivative liability of $4,781,069, which is included in current liabilities in our balance sheet. The Company designates these derivatives as cash flow hedges.

During 2003, the Company made payments to counter-parties totaling $4,527,061 as its net cost from hedging activities. This total includes $518,350 for the first quarter of 2003, $773,125 for the second quarter of 2003, $1,910,000 for the third quarter of 2003, and $1,325,586 for the fourth quarter of 2003.

At December 31, 2003, the Company had the following open derivative contracts to manage price risk on a portion of its natural gas production (all prices southwest Wyoming basis). (The Company s gas contains approximately 1.06 MMBtu per Mcf upon delivery at the sales point.)

Type	Contract Period	Volume- MMBTU / day	Average Price / MMbtu	Unrealized gain (loss) at 12/31/03*
Swap	January 2004	20,000	$ 5.47	$ 82,394
Swap	February 2004	5,000	$ 5.60	$ 24,728
Swap	Calendar 2004	20,000	$ 4.09	$(4,888,191)

* Unrealized Gain/(Loss) is not adjusted for income tax effect.

Table of Contents

The Company also utilizes fixed price forward gas sales at southwest Wyoming delivery points to economically 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, 2003. (The Company s average net interest in physical gas sales is approximately 80%.)

Contract Period	Volume - MMBTU / day	Average Price / MMbtu
Jan-Mar 2004	10,000	$6.04
April-Oct 2004	5,000	$4.44
Calendar 2004	30,000	$4.22
Calendar 2005	25,000	$4.07
Calendar 2006	10,000	$4.00

Subsequent to December 31, 2003 and through February 27, 2004, the Company has entered into the following additional contracts:

Type	Contract Period	Volume - MMBTU / day	Average Price / MMbtu
Swap	April-Oct 2004	5,000	$ 4.76
Physical	April-Oct 2004	10,000	$ 4.62
Physical	Calendar 2005	10,000	$ 4.42
Swap	Calendar 2005	5,000	$ 4.50
Swap	Calendar 2006	5,000	$ 4.20

The above contracts represent net volumes equal to approximately 48% of the Company s currently forecasted production for calendar 2004, 24% for Calendar 2005 and 7% for Calendar 2006.

RISK FACTORS AND CAUTIONARY STATEMENT FOR PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report contains or incorporates by reference forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements other than statements of historical facts included in this document, including without limitation, statements in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations regarding our financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of the Company s management for future operations, covenant compliance and those statements preceded by, followed by or that otherwise include the words believe , expects , anticipates , intends estimates , projects , target , goal , plans , objective , should , or similar expressions or variations on such expre forward-looking statements. The Company can give no assurances that the assumptions upon which such forward-looking statements are based will prove to be correct. Important factors that could cause actual results to differ materially from the Company s expectations are included throughout this document. The Cautionary Statements expressly qualify all subsequent written and oral forward-looking statements attributable to the Company or persons acting on the Company s behalf.

Competition. 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. The availability of a market for oil and natural gas production depends upon numerous factors beyond the control of the Company, including, but not limited to, the availability of other domestic or imported production, the locations and capacity of pipelines, and the effect of federal and state regulations on production.

Historically, the Company s projects have been financed through debt and internally generated cash flow. There is competition for capital to finance oil and gas drilling. The ability of the Company to obtain such financing is uncertain and can be affected by numerous factors beyond its control. The inability of the Company to raise capital in the future could have an adverse effect on certain areas of its business.

Marketing of Oil and Natural Gas. 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 addition, the Company may be unable to obtain favorable prices for the oil and natural gas it produces.

Volatility of Oil and Gas Prices. 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 (OPEC), 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.

Price of Wyoming Production. The Company produces natural gas in Wyoming. 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, the effect of a price decrease may more adversely affect the price received for the Company s Wyoming production than production in the other U.S. regions.

Government Regulations. 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 15 to April 30, 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 Wyoming Oil and Gas Conservation Commission. 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 environmental impact statements to assess the environmental impact of potential development, which can delay project implementation and/or result in the imposition of the environmental restrictions that could have a material impact on cost or scope.

Limited Financial Resources. 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 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.

Interruptions from Severe Weather. The Company s operations are conducted principally in the Rocky Mountain region. 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 mid-November to mid-May, but allow production activities all year round.

The Company Invests Heavily in Exploration. 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 capitalizes all direct costs of drilling an unsuccessful exploratory well in the period in which the well is determined not to be producible in commercial quantities. Under the full-cost method of accounting these costs are then depleted using the units of production method based on the Company s proven reserves.

Replacement of Reserves. 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.

Table of Contents

Operating Hazards and Uninsured Risks. 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, 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.

Drilling and Operating Risks. 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.

Drilling Plans Subject to Change. 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 the 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.

Financial Reporting Impact of Full Cost Method of Accounting. 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.

Risks Arising From Being Non-Operator in Bohai Bay. 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 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 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 of the Blocks could slow down or stop altogether. The Company currently does not believe it has sufficient funds to purchase Kerr-McGee s interests in these Blocks if they were offered. 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 on the Blocks, potentially diminishing the value of its Bohai Bay assets.

Political, Economic or International Factors Affecting China. 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. 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 PSCs terminate after 15 years of production, unless extended as provided for, which may be prior to the end of the productive life of the fields.

Operating Risks in China. 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 I, 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.

Certain Definitions

Terms used to describe quantities of oil and natural gas

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 gas to oil at the ratio of 6 Mcf of gas to 1 Bbl of oil.

BTU British Thermal Unit.

MBbl One thousand barrels.

Mcf One thousand cubic feet of natural gas.

Mcfe One thousand cubic feet of natural gas equivalent.

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 Unit.

Table of Contents

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 The discounted present value of proved reserves is identical to the standardized measure, 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 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.

Table of Contents

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 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.

Table of Contents

Item 8. Financial Statements and Supplementary Data.

MANAGEMENT S REPORT

The management of the Company is responsible for the preparation and integrity of all information contained in this Annual Report. The accompanying financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America. The financial statements include amounts that are management s best estimates and judgments.

The Company maintains a system of internal controls that provides management with reasonable assurance that the Company s assets are protected and that its published financial statements are reliable and free of material misstatement. Management is responsible for the effectiveness of internal controls. This is accomplished through established internal accounting control systems, policies and procedures, employee selection, appropriate delegation of authority and segregation of responsibilities.

The Audit Committee of the Board of Directors, composed solely of directors who are not officers or employees, meets regularly with the independent accountants. To ensure complete independence, the independent accountants have full and free access to the Audit Committee to discuss the results of their audits and the quality of financial reporting. The independent accountants do not provide any other services to the Company.

The independent accountants provide an objective independent review by their audit of the Company s financial statements. Their audit is conducted in accordance with auditing standards generally accepted in the United States of America and includes a review of internal accounting controls to the extent deemed necessary for the purposes of their audit.

Michael D. Watford
Chief Executive Officer
March 10, 2004

F. Fox Benton III
Chief Financial Officer

Table of Contents

INDEPENDENT AUDITORS REPORT

To Shareholders of
Ultra Petroleum Corp.:

We have audited the consolidated balance sheets of Ultra Petroleum Corp. and subsidiaries as of December 31, 2003 and 2002, and the consolidated statements of operations and deficit, shareholders equity and comprehensive loss, and cash flows for each of the years in the three-year period ended December 31, 2003. 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 auditing standards generally accepted in the United States of America. 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, 2003 and 2002, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2003, in accordance with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the Consolidated Financial Statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations.

KPMG, LLP
Denver, Colorado
March 2, 2004

Table of Contents

ULTRA PETROLEUM CORP.
CONSOLIDATED BALANCE SHEETS

(Expressed in U.S. Dollars)

ASSETS	December 31, 2003	December 31, 2002
Current Assets		
Cash and cash equivalents	$ 1,834,112	$ 1,417,711
Restricted cash	210,669	209,306
Accounts receivable	19,348,861	11,398,483
Inventory	13,589,270	
Prepaid drilling costs and other current assets	1,711,737	474,279
	36,694,649	13,499,779
Oil and gas properties, using the full cost method of accounting (Note 3)	307,863,722	207,362,408
Capital assets (Note 4)	1,212,006	1,011,699
TOTAL ASSETS	$345,770,377	$221,873,886
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 28,134,391	$ 13,839,031
Capital costs accrual	30,616,912	4,075,829
Long-term debt (Note 5)	99,000,000	86,000,000
Deferred income taxes	33,446,131	10,033,174
Other long-term obligations	5,120,213	3,858,810
Shareholders equity:		
Common stock (Note 6)	97,448,221	95,098,690
Treasury stock	(1,193,650)	(1,193,650)
Other comprehensive loss	(2,940,357)	(653,875)
Retained earnings	56,138,516	10,815,877
Total shareholders equity	149,452,730	104,067,042
Commitments and contingencies (Note 11)		
TOTAL LIABILITIES AND SHAREHOLDERS EQUITY	$345,770,377	$221,873,886

See accompanying notes to consolidated financial statements.

Approved on behalf of the Board:

, Director   , Director

Table of Contents

ULTRA PETROLEUM CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS AND DEFICIT

(Expressed in U.S. Dollars)	Year Ended December 31,		
	2003	2002	2001
REVENUES:			
Natural gas sales	$114,840,558	$38,502,971	$ 38,204,298
Oil sales	6,740,539	3,839,421	2,996,955
	121,581,097	42,342,392	41,201,253
EXPENSES:			
Production expenses and taxes	25,223,679	11,410,868	9,023,271
Depletion and depreciation	16,215,714	9,712,111	6,687,433
General and administrative	5,733,147	4,199,104	3,894,185
General and administrative, stock compensation	1,018,220	1,211,165	337,029
	48,190,760	26,533,248	19,941,918
OPERATING INCOME	73,390,337	15,809,144	21,259,335
OTHER INCOME (EXPENSE):			
Interest income	36,889	23,151	173,411
Interest expense	(2,850,916)	(2,691,608)	(1,687,172)
Other			220,016
	(2,814,027)	(2,668,457)	(1,293,745)
INCOME BEFORE INCOME TAXES	70,576,310	13,140,687	19,965,590
Income tax provision - deferred	25,253,671	5,059,166	2,086,762
NET INCOME	45,322,639	8,081,521	17,878,828
RETAINED EARNINGS (DEFICIT), beginning of period	10,815,877	2,734,356	(15,144,472)
RETAINED EARNINGS, end of period	$ 56,138,516	$10,815,877	$ 2,734,356
NET INCOME PER COMMON SHARE - BASIC	$ 0.61	$ 0.11	$ 0.25
NET INCOME PER COMMON SHARE - DILUTED	$ 0.58	$ 0.10	$ 0.24
Weighted average common shares outstanding - basic	74,231,553	73,770,841	72,371,839
Weighted average common shares outstanding - diluted	78,651,439	77,605,018	75,931,529

See accompanying notes to consolidated financial statements.

Table of Contents

ULTRA PETROLEUM CORP.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY AND COMPREHENSIVE LOSS
Common stock

Authorized
10,000,000 preferred shares
Unlimited common shares

Issued	Year Ended December 31, 2003 Number	Amount	Year Ended December 31, 2002 Number	Amount	Year Ended December 31, 2001 Number	Amount
Common Shares Balance, beginning of year	74,119,168	$95,098,690	73,318,418	$92,585,148	56,939,762	$50,838,663
Employee stock option exercises including income taxes	443,000	988,247	617,750	1,101,674	701,500	611,387
Employee stock plan grants	118,000	1,148,630	183,000	1,299,765	682,198	1,098,448
Fair value non-employee stock option grants		212,654		112,103		
Merger with Pendaries Petroleum Ltd.					14,994,958	40,036,650
Balance, end of period	74,680,168	$97,448,221	74,119,168	$95,098,690	73,318,418	$92,585,148
Treasury stock	(132,500)	(1,193,650)	(132,500)	(1,193,650)		
Other comprehensive loss - Fair value of derivative instruments, net of tax		(2,940,357)		(653,875)		

See accompanying notes to consolidated financial statements.

33

Table of Contents

ULTRA PETROLEUM CORP.
CONSOLIDATED STATEMENTS OF CASH FLOW

	Year Ended December 31,		
	2003	2002	2001
Cash flows from operating activities:			
Income for the year	$ 45,322,639	$ 8,081,521	$ 17,878,828
Adjustments to reconcile income to net cash provided by operating activities:			
Depletion and depreciation	16,215,714	9,712,111	6,687,433
Deferred income taxes	25,253,671	5,059,166	2,086,762
Stock compensation	1,018,220	1,211,165	337,030
Net changes in working capital:			
Restricted cash	(1,363)	(2,127)	(7,053)
Accounts receivable	(7,950,378)	(4,039,741)	919,796
Inventory	(13,589,270)		
Prepaid expenses and other current assets	(1,237,458)	1,695,459	(1,983,721)
Accounts payable and accrued liabilities	10,168,164	1,799,538	12,104,974
Other long-term obligations	1,261,403	(2,026,604)	(3,887,684)
Net cash provided by operating activities	76,461,342	21,490,488	34,136,365
Cash flows from investing activities:			
Oil and gas property expenditures	(115,837,250)	(61,257,518)	(56,575,708)
Change in oil and gas property expenditures in accounts payable	26,541,083	(2,288,540)	(3,280,946)
Purchase of capital assets	(737,021)	(814,205)	(317,592)
Proceeds from sale of oil and gas properties			312,365
Net cash used in investing activities	(90,033,188)	(64,360,263)	(59,861,881)
Cash flows from financing activities:			
Borrowings of long-term debt, gross	43,000,000	43,000,000	26,850,000
Payments on long-term debt, gross	(30,000,000)		(1,500,000)
Proceeds from issuance of common stock	988,247	1,101,674	611,387
Repurchase of common stock		(1,193,650)	
Net cash provided by financing activities	13,988,247	42,908,024	25,961,387
Net increase in cash and cash equivalents	416,401	38,249	235,871
Cash and cash equivalents, beginning of year	1,417,711	1,379,462	1,143,591
Cash and cash equivalents, end of year	$ 1,834,112	$ 1,417,711	$ 1,379,462
SUPPLEMENTAL INFORMATION			
Cash paid for:			
Interest	$ 2,850,916	$ 2,691,608	$ 1,687,172
Income taxes	$	$	$ 10,000

Supplemental schedule of non-cash investing activities Acquisitions			
Fair value of assets acquired	$	$	$ 43,950,263
Less: liabilities assumed			(4,225,978)
Cash acquired			312,365
Fair value of stock issued	$	$	$ 40,036,650

See accompanying notes to consolidated financial statements

Table of Contents

ULTRA PETROLEUM CORP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Expressed in U.S. dollars unless otherwise noted)
Years ended December 31, 2003, 2002 and 2001

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. 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 oil and gas operations whereby all costs associated with the exploration for and development of oil and gas reserves are capitalized to the Company s cost centers. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells and overhead charges directly related to acquisition, exploration and development activities. 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.

In January 2003 the Company adopted 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. Based on current estimates, the Company would record asset retirement obligations (using a 10% discount rate) and a cumulative effect of change in accounting principle on prior years, related to the depreciation and accretion expense that would have been reported had the fair value of the asset retirement obligation, and corresponding increase in the carrying amount of the related long-lived asset. Currently the Company s assessment has been deemed not material.

The capitalized costs, together with the costs of production equipment, are depleted 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 upon relative energy content.

Costs of acquiring and evaluating unproved properties are initially excluded from the costs subject to depletion. These unproved properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to the costs subject to depletion.

The total capitalized cost of oil and gas properties less accumulated depletion is limited to an amount equal to the estimated future net cash flows from proved reserves, discounted at 10%, using year-end prices, plus the cost (net of impairment) of unproved properties as adjusted for related tax effects (the full cost ceiling test limitation).

Proceeds from the sale of oil and gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion.

Substantially all of the Company s exploration, development and production activities are conducted jointly with others and, accordingly, these financial statements reflect only the Company s proportionate interest in such activities.

(g) Derivative transactions: The Company has entered into commodity price risk management transactions to manage its exposure to gas price volatility. These transactions are in the form of price swaps with financial institutions and other credit worthy counter parties. 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.

(h) Income taxes: The Company uses the asset and liability method of accounting for income taxes under which deferred tax assets and liabilities are recognized for the future tax consequences. Accordingly, deferred tax liabilities and assets are determined based on the temporary differences between the financial statement and tax basis of assets and liabilities, using the enacted tax rates in effect for the year in which the differences are expected to reverse.

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

The following table provides a reconciliation of the components of basic and diluted net income per common share for the years ended December 31, 2003, 2002 and 2001:

	Year Ended December 31,		
	2003	**2002**	**2001**
Net income	$45,322,639	$ 8,081,521	$17,878,828
Weighted average common shares outstanding during the period	74,231,553	73,770,841	72,371,839
Effect of dilutive instruments	4,419,886	3,834,177	3,559,690
Weighted average common shares outstanding during the period including the effects of dilutive instruments	78,651,439	77,605,018	75,931,529
Basic earnings per share	$ 0.61	$ 0.11	$ 0.25
Diluted earnings per share	$ 0.58	$ 0.10	$ 0.24
Number of shares not included in dilutive earnings per share that would have been antidilutive because the exercise price was greater than the average market price of the common shares	13,630	130,570	373,942

(j) Use of estimates: Preparation of consolidated financial statements in accordance with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the

Table of Contents

financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

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

(l) Accounting for stock-based compensation: In December 2002, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS No. 148), Accounting for Stock-Based Compensation-Transaction and Disclosure , SFAS No. 148 amends SFAS No. 123, Accounting for Stock-Based Compensation to provide alternative methods of transactions for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on the reported results. The provisions of SFAS No. 148 are effective for financial statements for fiscal years ending after December 15, 2002.

SFAS No. 123, Accounting for Stock Based Compensation , 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 using the intrinsic value based method prescribed by APB Opinion No. 25, Accounting for Stock Issued to Employees (APB No. 25), 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. Had the Company reported compensation costs as determined by the fair value method of accounting for option grants to employees and directors, net income and net income per common share would approximate the following pro forma amounts:

	For the Year Ended December 31,		
	2003	2002	2001
Net income:			
As reported	$45,322,639	$8,081,521	$17,878,828
Pro forma	$43,799,671	$5,167,990	$14,924,923
Net income per common share:			
Basic:			
As reported	$ 0.61	$ 0.11	$ 0.25
Pro forma	$ 0.59	$ 0.07	$ 0.21
Diluted:			
As reported	$ 0.58	$ 0.10	$ 0.24
Pro forma	$ 0.56	$ 0.07	$ 0.20

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, 2003, expected volatility of approximately 25%, at December 31, 2002, expected volatility of 30%, at December 31, 2001, expected volatility of 30%. All options have expected lives of ten years.

(m) Revenue Recognition. Natural gas revenues are recorded on the entitlement method. Under the entitlement method, revenue is recorded when title passes based on the Company s net interest. The Company records its entitled share of revenues based on estimated production volumes. Subsequently, these estimated volumes are adjusted to reflect actual volumes that are supported by third party pipeline statements or cash receipts. Since there is a ready market for natural gas, the Company sells the majority of its products soon after production at various locations at which time title and risk of loss pass to the buyer. Gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total gas production. Any amount received in excess of the Company s share is treated as a liability. If the Company receives less than it is entitled, the underproduction is recorded as a receivable. At December 31, 2003 and 2002, the Company had net gas imbalance receivables of $2 million and $1 million, respectively.

(n) Impact of recently issued accounting pronouncements: None that affect the Company.

Table of Contents

2. ACQUISITION OF PENDARIES PETROLEUM LTD:

Effective January 16, 2001, the Company completed its acquisition of 100% of the outstanding shares of Pendaries Petroleum Ltd. (Pendaries) and its wholly owned subsidiary Sino-American Energy Corporation in exchange for 14,994,958 shares of Ultra Petroleum Corp. common stock valued at $2.67 per share. The value of the shares was based on the average price of the shares a few days prior to and a few days subsequent to the date the transaction was closed. The transaction was accounted for using the purchase method of accounting and was valued at $40 million. The impact of the acquisition increased the undeveloped portion of the Company s full cost pool by $43 million and also carried to the balance sheet a net deferred tax liability of $962,081. This deferred tax liability was created as a result of a difference between the book and tax basis in Sino-American Energy Corporation s oil and gas properties. Accordingly, Pendaries results of operations have been included in the consolidated financial statements of income from the effective date of acquisition. The consolidated balance sheet dated December 31, 2003 includes the assets and liabilities, as well as the adjustments required to record the acquisition in accordance with purchase accounting.

3. OIL AND GAS PROPERTIES:

	December 31, 2003	December 31, 2002
Developed Properties:		
Acquisition, equipment, exploration, development drilling and environmental costs	$249,784,562	$150,986,843
Less accumulated depletion, depreciation and amortization	(38,495,605)	(22,816,605)
	211,288,957	128,170,238
Unproved properties China	80,970,244	64,873,186
Unproved properties Wyoming	15,604,521	14,318,984
	$307,863,722	$207,362,408

4. CAPITAL ASSETS:

	December 31, 2003 Cost	December 31, 2003 Accumulated Depreciation	December 31, 2003 Net Book Value	December 31, 2002 Net Book Value
Computer equipment	$ 686,165	$ 497,789	$ 188,376	$ 199,302
Office equipment	233,255	155,028	78,227	90,401
Field equipment	304,626	188,985	115,641	44,191
Other	1,532,917	703,155	829,762	677,805
	$2,756,963	$1,544,957	$1,212,006	$1,011,699

5. LONG-TERM DEBT:

	December 31, 2003	December 31, 2002
Bank indebtedness	$ 99,000,000	$86,000,000
Other long-term obligations	5,120,213	3,858,810
	$104,120,213	$89,858,810

Bank indebtedness: The Company (through its subsidiary) participates in a long-term credit facility with a group of banks led by Bank One N.A. The agreement specifies an aggregate borrowing base of $200 million at December 12, 2003. At December 31, 2003, the Company had $99 million borrowings outstanding and $101 million in unused borrowings available under the credit facility.

The credit facility matures on March 1, 2006. The notes bear interest at either the bank s prime rate plus a margin of one-half of one percent (0.50%) to one and one-quarter percent (1.25%) based on the percentage of available credit drawn or at LIBOR plus a margin of one and one-half percent (1.50%) to two and one-quarter percent (2.25%) based on the percentage of available credit drawn. An average annual commitment fee of 0.375% is charged quarterly for any unused portion of the credit line.

Table of Contents

The borrowing base is subject to periodic (at least semi-annual) review and re-determination by the bank 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. 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 and may be required to make immediate principal repayment. As of December 31, 2003, the Company was in compliance with the covenants and required ratios.

Other long-term obligations: These costs relate to the long-term portion of production taxes payable and dollars associated with imbalanced production.

6. COMMON STOCK:

(a) Stock options: The following table summarizes the changes in stock options for the three-year period ending December 31, 2003:

	Number of Options	Weighted Average Exercise Price (US$)
Balance, December 31, 2000	4,525,000	$ 0.51 to $2.65
Granted	1,630,000	$ 2.99 to $5.23
Exercised	(701,500)	$ 0.64 to $3.12
Cancelled	(22,500)	$ 1.14 to $5.23
Balance, December 31, 2001	5,431,000	$ 0.51 to $5.23
Granted	748,500	$ 7.82 to $8.86
Exercised	(617,750)	$ 0.64 to $5.23
Balance, December 31, 2002	5,561,750	$ 0.51 to $8.86
Granted	797,500	$ 9.66 to $14.21
Exercised	(443,000)	$ 0.64 to $8.86
Cancelled	(13,750)	$ 8.86 to $9.66
Balance, December 31, 2003	5,902,500	$ 0.51 to $14.21

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. The Company s stock options vest each quarter over a one-year period. At the end of the one year the stock options are fully vested.

The following table summarizes information about the stock options outstanding at December 31, 2003:

	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)
$0.51 - 1.14	3,023,500	5.65	$ 0.89	3,023,500	5.65	$ 0.89
$2.65 - 5.23	1,378,000	7.24	$ 4.02	1,378,000	7.24	$ 4.02
$7.82 - 14.21	1,501,000	8.89	$ 9.45	1,081,000	6.40	$ 9.13

7. FINANCIAL INSTRUMENTS:

The Company uses 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 Company recognizes all derivative instruments as assets or liabilities in 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 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 non-operating income or expense. At December 31, 2003, the Company had a current derivative liability of $4,781,069, which is included in current liabilities in the balance sheet. The Company has designated these derivatives as cash flow hedges.

During 2003, the Company made payments to counter-parties totaling $4,527,061 as its net cost from hedging activities. This total includes $518,350 for the first quarter of 2003, $773,125 for the second quarter of 2003, $1,910,000 for the third quarter of 2003, and $1,325,586 for the fourth quarter of 2003.

At December 31, 2003, the Company had the following open derivative contracts to manage price risk on a portion of its natural gas production (all prices southwest Wyoming basis). (The Company s gas contains approximately 1.06 MMBtu per Mcf upon delivery at the sales point.)

	Contract	Volume	Average	Unrealized gain
Type	Period	MMBTU / day	Price / MMbtu	(loss) at 12/31/03*
Swap	January 2004	20,000	$ 5.47	$ 82,394
Swap	February 2004	5,000	$ 5.60	$ 24,728
Swap	Calendar 2004	20,000	$ 4.09	$(4,888,191)

* Unrealized Gain/(Loss) is not adjusted for income tax effect

The Company also utilizes fixed price forward gas sales at southwest Wyoming delivery points to economically 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, 2003. (The Company s average net interest in physical gas sales is approximately 80%.)

Contract	Volume	Average
Period	MMBTU / day	Price / MMbtu
Jan-Mar 2004	10,000	$6.04
April-Oct 2004	5,000	$4.44
Calendar 2004	30,000	$4.22
Calendar 2005	25,000	$4.07
Calendar 2006	10,000	$4.00

Subsequent to December 31, 2003 and through February 27, 2004, the Company has entered into the following additional contracts:

		Volume	Average
Type	Contract Period	MMBTU / day	Price / MMbtu
Swap	April-Oct 2004	5,000	$ 4.76
Physical	April-Oct 2004	10,000	$ 4.62
Physical	Calendar 2005	10,000	$ 4.42
Swap	Calendar 2005	5,000	$ 4.50
Swap	Calendar 2006	5,000	$ 4.20

The above contracts represent net volumes equal to approximately 48% of the Company s currently forecasted production for calendar 2004, 24% for Calendar 2005 and 7% for Calendar 2006.

8. INCOME TAXES:

The (recovery of) provision for income taxes for the years ended December 31, 2003 and December 31, 2002 vary from the amounts that would be computed by applying the U.S. Federal income tax rate of 35% to pretax income as a result of the following:

Table of Contents

	December 31, 2003	December 31, 2002
Federal tax expense at statutory rate	$24,701,708	$4,599,240
State income tax expense	455,557	456,497
Adjustment for foreign losses	80,287	94,087
Percentage depletion	(87,500)	(185,016)
Other	103,619	94,358
Actual income tax expense	$25,253,671	$5,059,166

The tax effects of temporary differences that give rise to significant portions of the future tax assets and liabilities are as follows:

	December 31, 2003	December 31, 2002
Future tax assets:		
Net operating loss carryforward	$ 9,090,091	$ 9,878,862
Tax effect of hedging activity	1,840,713	
Other	843,929	797,440
	11,774,733	10,676,302
Less valuation allowance		
Total future assets	11,774,733	10,676,302
Future tax liabilities		
Property and equipment	(45,220,864)	(20,709,476)
Net future tax assets (liabilities)	$(33,446,131)	$(10,033,174)

At December 31, 2003, the Company has available non-capital loss carryforwards as follows:

	Losses for Financial Statements	Timing Differences	Losses for Tax Purposes	Expiry Dates
Canada (Cdn dollars)	$9,827,916	$ (122,633)	$ 9,705,283	2004-2010
United States (US dollars)	$	$25,250,253	$25,250,253	2012-2021

During 2001, the Company fully utilized available net operating loss carryforwards attributable to continuing operations for financial statement purposes.

The benefit of the Canadian loss carryforwards could only be utilized if the Company were to generate taxable income in Canada. The Company currently has no operations in Canada; any potential benefit from these losses has been excluded from the calculation of deferred taxes.

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 U.S. 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 $299,832, $236,765 and $187,255 for the years ended December 31, 2003, 2002 and 2001, respectively.

10. DIFFERENCES BETWEEN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES IN CANADA AND THE UNITED STATES:

Currently under Canadian GAAP, there is not a provision in place to expense stock-based compensation as with FASB Statement No. 123 Accounting for Stock-Based Compensation. However, there was an exposure draft issued in December 2002 that would essentially harmonize Canadian accounting standards to U.S. GAAP. The proposed effective date for implementing Stock-Based Compensation and Other Stock-Based Payments, Section 3870, is January 1, 2004. In the year ending December 31, 2003, the Company recorded, to the full cost pool under capitalized general and administrative expenses of $212,653, a consultant stock-based compensation expense of $212,653. Under current Canadian GAAP, this amount would have been recognized as a disclosure item, with no impact on the financial statements.

Recorded in other comprehensive income in the Equity section of our balance sheet is an offset to a liability that measures a future effect of the fixed price to index price swap agreements that the Company currently has in place (Note 7). We have recorded this in compliance with FAS 133 addressing accounting impacts of derivative instruments. Currently under Canadian GAAP the future effects of derivative instruments are recorded through revenue in the period in which the production is sold. The total future value of the swap is not captured as an asset or liability, and the term Other Comprehensive Income, is not recognized in Canada. In 2002, the Canadian Accounting Standards Board issued a draft proposal to put in place Canadian standards harmonizing with U.S. standards on financial instruments. Canadian enterprises would then have the choice to apply accounting policies and practices that are in accordance with both U.S. and Canadian GAAP.

11. COMMITMENTS AND CONTINGENCIES:

In May of 2003 the Company amended its prior office lease in Englewood, Colorado, which it has committed to through June 2008. The Company s total commitment of this lease is $734,578. 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 commitment of $364,941. The total commitment for both offices is $1,099,519.

As of December 31, 2003 the Company committed to drilling obligations in progress that will carry over into 2004. The total capital expenditures for operations in progress were $12,384,391.

On October 16, 2003 the 15 year contract, which provides for up to an additional 10 years, was signed by the Operator to lease an FPSO. The Company ratified the contract for its net share which is 8.92%. 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. Lease cancellation on the part of the Company prior to the FPSO starting offshore operations would commit the Company to its 8.92% share of up to $50 million in cancellation fees. The lease cancellation fee, after commencement of offshore operations, would be based on a sliding time-scale (cancellation fee decreases with time) with 8.92% of $50 million the maximum cancellation fee. The Company considers it very unlikely that a lease cancellation situation will occur. Due to these 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 total operating leases were $621,065.

The Company is currently involved in various other 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 carrying value for notes payable approximates fair market value because the interest rates are similar to the current rates presently available to the Company for loans with similar terms and maturity. It is not practicable to estimate the fair values of amounts due to and from related parties due to the related party nature of the amounts and the absence of a ready market for such instruments.

13. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED):

		Income
	Revenues	**Before**

	from Continuing Operations	Expenses	Income Tax Provision	Income Tax Provision	Net Income	Basic Earnings Per Share	Diluted Earnings Per Share
			(in thousands, except for per share data)				
2003							
First Quarter	$ 24,671	$11,303	$13,368	$ 5,147	$ 8,221	$0.11	$0.11
Second Quarter	$ 23,466	$11,075	$12,391	$ 4,771	$ 7,620	$0.10	$0.10
Third Quarter	$ 29,291	$12,422	$16,869	$ 6,541	$10,328	$0.14	$0.13
Fourth Quarter	$ 44,153	$16,205	$27,948	$ 8,795	$17,188	$0.26	$0.24
	$121,581	$51,005	$70,576	$25,254	$43,357		

42

Table of Contents

	Revenues from Continuing Operations	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)				
2002							
First Quarter	$ 9,106	$ 6,323	$ 2,783	$1,071	$1,712	$ 0.02	$ 0.02
Second Quarter	$ 8,143	$ 6,161	$ 1,982	$ 676	$1,306	$ 0.02	$ 0.02
Third Quarter	$ 8,671	$ 7,108	$ 1,563	$ 602	$ 961	$ 0.01	$ 0.01
Fourth Quarter	$16,422	$ 9,610	$ 6,812	$2,710	$4,102	$ 0.06	$ 0.05
	$42,342	$29,202	$13,140	$5,059	$8,081		

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, 2003, 2002 and 2001 are based upon estimates prepared by Netherland, Sewell & Associates, Inc. dated January 23, 2004, January 21, 2003 and February 21, 2002, respectively. These are estimated quantities of proved oil and gas reserves for the Company and the changes in total proved reserves as of December 31, 2003, 2002 and 2001. All such reserves are located in the Green River Basin, Wyoming.

B. ANALYSES OF CHANGES IN PROVEN RESERVES:

	Oil (Bbls)	Gas (Mcf)
Reserves, December 31, 2000	1,290,300	160,390,000
Extensions, discoveries and additions	2,222,900	278,057,000
Production	(116,400)	(11,500,000)
Revisions	86,000	(3,117,400)

Reserves, December 31, 2001	3,482,800	423,829,600
Extensions, discoveries and additions	1,101,500	139,044,000
Production	(151,200)	(16,496,000)
Revisions	1,125,900	120,743,400
Reserves, December 31, 2002	5,559,000	667,121,000
Extensions, discoveries and additions	2,894,700	361,298,700
Production	(211,600)	(27,621,800)
Revisions	100,400	22,569,400
Reserves, December 31, 2003	8,342,500	1,023,367,300
Proved developed reserves:		
December 31, 2000	688,000	85,141,000
December 31, 2001	1,295,000	150,397,000
December 31, 2002	2,003,000	222,608,000
December 31, 2003	3,028,000	359,072,000

C. STANDARDIZED MEASURE:

The following table sets forth a standardized measure of the estimated discounted future net cash flows attributable to the Company s proved gas reserves. 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 $5.59, $2.94, and $2.05 per Mcf of gas at December 31, 2003, 2002 and 2001, 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

Table of Contents

between pretax net cash flows relating to the Company s proved reserves and the tax basis of proved properties and available operating loss carryovers (US $000).

	December 31, 2003	December 31, 2002	December 31, 2001
Future cash inflows	$ 5,986,603	$2,132,521	$ 939,441
Future production costs	(1,171,314)	(569,034)	(257,960)
Future development costs	(358,811)	(254,892)	(149,806)
Future income taxes	(1,620,437)	(432,663)	(184,164)
Future net cash flows	2,836,041	875,932	347,511
Discounted at 10%	(1,700,528)	(558,967)	(228,252)
Standardized measure of discounted future net cash flows	$ 1,135,513	$ 316,965	$ 119,259
Pre-tax standardized measure SEC PV-10	$ 1,784,314	$ 473,528	$ 182,460

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, 2003	December 31, 2002	December 31, 2001
Standardized measure, beginning	$ 316,965	$119,259	$ 310,001
Net revisions	41,715	119,995	(1,820)
Extensions, discoveries and other changes	680,136	136,194	177,819
Sales of reserves in place			
Changes in future development costs	(10,603)	(40,825)	(31,066)
Sales of oil and gas, net of production costs	(96,357)	(39,985)	(39,762)
Net change in prices and production costs	605,892	91,501	(407,434)
Development costs incurred during the period that reduce future development costs	8,886	1,573	
Accretion of discount	47,353	18,246	49,324
Net change in income taxes	(458,474)	(88,993)	62,197

Standardized measure, ending	$1,135,513	$316,965	$ 119,259

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.

Table of Contents

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

UNITED STATES

Years Ended	December 31, 2003	December 31, 2002	December 31, 2001
Acquisition costs unproved properties	$ 1,603	$ 937	$ 310
Exploration	55,095	22,722	33,845
Development	43,111	28,620	11,950
Total	$ 99,809	$ 52,279	$ 46,105

CHINA

Years Ended	December 31, 2003	December 31, 2002	December 31, 2001
Acquisition costs unproved properties	$ 16,027	$ 8,979	$ 11,944
Exploration			
Development			
Total	$ 16,027	$ 8,979	$ 11,944

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

Years Ended	December 31, 2003	December 31, 2002	December 31, 2001
Oil and gas revenue	$121,581	$ 43,342	$41,201
Production expenses and taxes	(25,224)	(11,411)	(9,023)
Depletion and depreciation	(16,216)	(9,712)	(6,687)

Total	$ 80,141	$ 22,219	$ 25,491

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

None

Item 9A. Controls and Procedures.

The Company s management, including the Company s principal executive officer and principal financial officer, has evaluated the effectiveness of the Company s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this Annual Report on Form 10-K. Based upon that evaluation, the Company s principal executive officer and principal financial officer have concluded that the disclosure controls and procedures were effective as of the end of the period covered by this Annual Report on form 10-K.

There were no changes in the Company s internal control over financial reporting that occurred during the Company s last fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company s internal control over financial reporting.

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, 2003 and is incorporated herein by reference.

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, 2003 and is incorporated herein by reference.

Table of Contents

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, 2003, and is incorporated herein by reference.

Plan Category	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in the first column)
Equity compensation plans approved by security holders at 12/31/2003	5,902,500	$ 3.80	4,839,000
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	5,902,500	$ 3.80	4,839,000

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, 2003 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, 2003 and is incorporated herein by reference.

Part IV

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

(a) The following documents are filed as part of this report:

1. Financial Statements: See Index to Consolidated Financial Statements in 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. Exhibits designated with a + constitute a management contract or compensatory plan or arrangement required to be filed as an exhibit pursuant to Item 14(c) of Form 10-K.

(b) The Company filed a current report on Form 8-K dated October 28, 2003 disclosing under Item 12 Results of Operations and Financial Conditions its third quarter earnings conference call for November 4, 2003.

The Company filed a current report on Form 8-K dated November 4, 2003 disclosing under Item 12 Results of Operations and Financial Conditions its earnings for the third quarter 2003.

Table of Contents

Exhibit Number	Description
3.1	Articles of Incorporation of Ultra Petroleum Corp. - (incorporated by reference to Exhibit 3.1 of the Company s Quarterly Report on Form 10-Q for the period ended June 30, 2001)
3.2	By-Laws of Ultra Petroleum Corp. - (incorporated by reference to Exhibit 3.2 of the Company s Quarterly Report on Form 10-Q for the period ended June 30, 2001)
*3.3	Code of Ethics for Chief Executive Officer and Senior Financial Officers of Ultra Petroleum Corp.
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	Third Amendment to First Amended and Restated Credit Agreement dated December 12, 2003 among Ultra Resources, Inc., Bank One, N.A., Union Bank of California, N.A., Guaranty Bank FSB, Hibernia National Bank, Compass Bank, Bank of Scotland and Fleet National Bank.
10.2	Second Amendment to First Amended and Restated Credit Agreement dated May 14, 2003 among Ultra Resources, Inc., Bank One N.A., Union Bank of California, N.A., Guaranty Bank FSB, Hibernia National Bank, Compass Bank and Bank of Scotland (incorporated by reference to Exhibit 10.1 of the Company s Quarterly Report on Form 10-Q for the period ended June 30, 2003)
10.3	First Amendment to First Amended and Restated Credit Agreement dated November 4, 2002 among Ultra Resources, Inc., Bank One N.A., Union Bank of California, N.A., Hibernia National Bank, Guaranty Bank, FSB and Compass Bank (incorporated by reference to Exhibit 10.1 to the Company s annual report on Form 10-Q for period ended December 31, 2002)
10.4	First Amended and Restated Credit Agreement dated March 1, 2002 among Bank One, N.A., Union Bank of California, N.A., Guaranty Bank, FSB, Hibernia National Bank, Ultra Resources, Inc. and Banc One Capital Markets, Inc. (incorporated by reference to Exhibit 10.1 to the Company s Annual Report on Form 10-K for the period ended December 31, 2001)
10.5	First Amendment to Credit Agreement dated July 19, 2001 (incorporated by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the period ended September 30, 2001)
10.6	Credit Agreement dated March 22, 2000 (incorporated by reference to Exhibit 10.1 of the Company s Quarterly Report on Form 10-Q for the period ended June 30, 2001)
10.7	Articles of Merger dated July 16, 2001 (incorporated by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the period ended September 30, 2001)
10.8	Plan of Merger and Reorganization dated July 16, 2001 (incorporated by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the period ended

	September 30, 2001)
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.
*31.1	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)
*31.2	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a)

Table of Contents

*32.1	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)
*32.2	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a)

* Filed herewith

SIGNATURES

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

ULTRA PETROLEUM CORP.

Date: March 12, 2004

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

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
Michael D. Watford	Chairman of the Board, Chief Executive Officer and President	March 12, 2004
W. Charles Helton	Director	March 12, 2004
James E. Nielson	Director	March 12, 2004
Robert E. Rigney	Director	March 12, 2004
James C. Roe	Director	March 12, 2004
F. Fox Benton III	Chief Financial Officer	March 12, 2004

Table of Contents

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Table of Contents

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