VINTAGE PETROLEUM INC
Form 10-K
March 12, 2004

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

OR

¨ **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 1-10578

VINTAGE PETROLEUM, INC.

(Exact name of registrant as specified in its charter)

Delaware	**73-1182669**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

110 West Seventh Street **Tulsa, Oklahoma**	**74119-1029**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (918) 592-0101

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

Title of each class	Name of each exchange on which registered
Common Stock, $0.005 Par Value	New York Stock Exchange
Preferred Share Purchase Rights	New York 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 requirements 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 the 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 ¨

As of June 30, 2003, the aggregate market value of the Registrant s Common Stock held by non-affiliates was approximately $579,700,000.

As of February 27, 2004, 64,317,208 shares of the Registrant s Common Stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant s Proxy Statement for the Annual Meeting of Stockholders to be held May 11, 2004, are incorporated by reference into Part III of this Form 10-K.

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VINTAGE PETROLEUM, INC.

FORM 10-K

YEAR ENDED DECEMBER 31, 2003

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Certain Definitions

As used in this Form 10-K:

Unless the context requires otherwise, all references to Vintage, Company, we, our, ours, and us refer to Vintage Petroleum, Inc., its consolidated subsidiaries and its proportionately consolidated general partner and limited partner interests in various joint ventures.

Oil means crude oil, condensate and natural gas liquids. Condensate means hydrocarbons which are in a gaseous state under reservoir conditions but which become liquid at the surface and may be recovered by conventional separators. Natural gas liquids means hydrocarbons found in natural gas which may be extracted as liquified petroleum gas and natural gasoline. Gas means natural gas.

Mcf means thousand cubic feet, MMcf means million cubic feet, and Bcf means billion cubic feet. Btu means British thermal units, the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit, and MMBtu means million British thermal units. Bbl means barrel, or 42 U.S. gallons liquid volume, MBbls means thousand barrels and MMBbls means million barrels. BOE means equivalent barrels of oil, MBOE means thousand equivalent barrels of oil and MMBOE means million equivalent barrels of oil. Unless otherwise indicated in this Form 10-K, gas volumes are stated at the legal pressure base of the state or area in which the reserves are located and at 60° Fahrenheit. BOE are determined using the ratio of six Mcf of gas to one Bbl of oil.

Working interest means the operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and to receive a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith. Royalty interest means an interest in an oil and gas property entitling the owner to a share of oil and gas production free of cost of production.

The term gross refers to the total acres or wells in which Vintage has a working interest, and net refers to gross acres or wells multiplied by the percentage working interest owned by Vintage. Net production means production that is owned by Vintage less royalties and production due others.

Development well means a well drilled within the proved area of an oil or gas reservoir, as indicated by reasonable interpretation of available data, to the depth of a stratigraphic horizon known to be productive. Exploratory well means a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend the proved limits of a known reservoir. Dry hole means a well found to be incapable of producing either oil or gas in sufficient quantities to justify completion of the well. Productive well means a well that is producing oil or gas or that is capable of production including gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.

Infill drilling means drilling of an additional well or wells provided for by an existing spacing order to more adequately drain a reservoir. Recompletion means the completion for production of an existing wellbore in a different formation or producing horizon, either deeper or shallower, from that in which the well was previously completed. Workover means remedial operations on a well with the intention of restoring or increasing production from the same zone, including plugging back, squeeze cementing, reperforating, cleanout and acidizing.

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. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Developed acreage means the number of acres which are allocated or assignable to producing wells or wells capable of production. Undeveloped acreage means the number of acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether such acreage contains proved oil and gas reserves.

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Forward-Looking Statements

This Form 10-K includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included in this Form 10-K which address activities, events or developments which we expect, believe or anticipate will or may occur in the future are forward-looking statements. The words believes, intends, expects, anticipates, projects, estimates, predicts and similar expr are also intended to identify forward-looking statements.

These forward-looking statements include, among others, such things as:

- **amounts and nature of future capital expenditures;**
- **wells to be drilled or reworked;**
- **oil and gas prices and demand;**
- **exploitation and exploration prospects;**
- **estimates of proved oil and gas reserves;**
- **reserve potential;**
- **development and infill drilling potential;**
- **expansion and other development trends of the oil and gas industry;**
- **business strategy;**
- **production of oil and gas reserves;**
- **expansion and growth of our business and operations; and**
- **events or developments in foreign countries, including estimates of oil export levels.**

These statements are based on certain assumptions and analyses we made in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate in the circumstances.

However, whether actual results and developments will conform with our expectations and predictions is subject to a number of risks and uncertainties which could cause actual results to differ materially from our expectations, including:

- **risk factors discussed in this Form 10-K and listed from time to time in our filings with the Securities and Exchange Commission;**
- **oil and gas prices;**
- **exploitation and exploration successes;**
- **actions taken and to be taken by the foreign governments as a result of economic conditions;**
- **continued availability of capital and financing;**
- **general economic, market or business conditions;**
- **acquisitions and other business opportunities (or lack thereof) that may be presented to and pursued by us;**
- **changes in laws or regulations; and**
- **other factors, most of which are beyond our control.**

Consequently, all of the forward-looking statements made in this Form 10-K are qualified by these cautionary statements and there can be no assurance that the actual results or developments anticipated by us will be realized or, even if substantially realized, that they will have the expected consequences to or effects on us or our business or operations. We assume no obligation to update publicly any such forward-looking statements, whether as a result of new information, future events or otherwise.

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PART I

Items 1 and 2. Business and Properties.

Website Access to Reports

Our public internet site is http://www.vintagepetroleum.com. We make available free of charge through our internet site, via a link to the EDGAR database of the Securities and Exchange Commission (SEC), our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

In addition, we make available on http://www.vintagepetroleum.com our annual report to stockholders. You will need the Adobe Acrobat Reader software installed on your computer to view this document, which is in PDF format. If you do not have Adobe Acrobat Reader installed, a link to Adobe Systems Incorporated s internet site, where you can download the software, is provided.

General

We are an independent energy company with operations primarily in the exploration and production, gas marketing and oil and gas gathering and processing segments of the oil and gas industry. We are focused on the acquisition of oil and gas properties which contain the potential for increased value through exploitation and exploration. Through our experienced management and technical staff, we have been successful in realizing such potential on prior acquisitions through workovers, recompletions, secondary recovery operations, operating cost reductions and the drilling of development or exploratory wells. In addition to our exploration and development activities associated with acquisitions, we continue to build an inventory of exploration prospects in North America that may impact production in the near term as well as high potential frontier prospects that may impact production in the longer term.

At December 31, 2003, we owned and operated producing properties in nine states in the U.S., with our proved reserves in the U.S. located primarily in four core areas: West Coast, Gulf Coast, East Texas and Mid-Continent. During 2001, we significantly expanded our North American operations in Canada through the acquisition of 100 percent of Genesis Exploration Ltd. (Genesis, now Vintage Petroleum Canada, Inc.). See Acquisitions. Additionally, we have international core areas located in Argentina and Bolivia. In Argentina, we own 21 oil concessions, 18 of which we operate. Fourteen of these operated concessions are located in the south flank of the San Jorge Basin in southern Argentina. We expanded our Argentina core area into the Cuyo Basin in western Argentina with the purchase of the Piedras Colorados and Cachueta concessions in 2000, and the purchase of the La Ventana and Rio Tunuyan concessions in 2001. See Acquisitions. In Bolivia, we own and operate three concessions in the Chaco Plains area of southern Bolivia and the Naranjillos concession located in the Santa Cruz Province. We have exploration activities currently ongoing in Yemen, Italy and Bulgaria. Initial production in Yemen is expected to begin late in the first quarter of 2004. We also previously operated three blocks in the Oriente Basin in Ecuador. However, on January 31, 2003, we sold all of our operations in Ecuador. See Divestitures.

As of December 31, 2003, we owned interests in 2,660 gross (2,323 net) productive wells in the U.S., of which approximately 92 percent are operated by us, 645 gross (420 net) productive wells in Canada, of which approximately 58 percent are operated by us, 1,518 gross (1,371 net) productive wells in Argentina, of which approximately 84 percent are operated by us, 14 gross (13 net) productive wells in Bolivia, all of which are operated by us and three gross (two net) productive wells in Yemen, all of which are operated by us. As of December 31, 2003, our properties had proved reserves of 447.1 MMBOE, comprised of 292.8 MMBbls of oil and 926.0 Bcf of gas, with a present value of estimated future net revenues before income taxes (utilizing a 10 percent discount rate) of $3.5 billion and a standardized measure of discounted future net cash flows of $2.4 billion. From the first quarter of 1999 through the fourth quarter of 2003, we increased our average net daily production from continuing operations from 40,800 Bbls of oil to 48,400 Bbls of oil and from 120.9 MMcf of gas to 155.1 MMcf of gas.

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Financial information relating to our industry segments is set forth in Note 10 Segment Information to our consolidated financial statements included elsewhere in this Form 10-K.

We were incorporated in Delaware on May 31, 1983. Our principal office is located at 110 West Seventh Street, Tulsa, Oklahoma 74119-1029, and our telephone number is (918) 592-0101.

Business Strategy

Our overall goal is to maximize value through profitable growth in oil and gas reserves and production. We have been successful at achieving this goal through an ongoing strategy of (a) acquiring producing oil and gas properties with significant upside potential at favorable prices, (b) focusing on exploitation, development and exploration activities to maximize production and ultimate reserve recovery on existing properties and undeveloped properties, (c) maintaining efficient operations and (d) maintaining financial flexibility. Key elements of our strategy include:

Acquisitions of Producing Properties. We have an experienced management and technical team which focuses on acquisitions of operated producing properties that meet our selection criteria, which include (a) significant potential for increasing reserves and production through exploitation, development and exploration, (b) favorable purchase price and (c) opportunities for improved operating efficiency. Our emphasis on property acquisitions reflects our belief that continuing consolidation and restructuring activities on the part of major integrated, large independent and national oil companies has afforded in the past, and should afford in the future, favorable opportunities to purchase domestic and international properties. This acquisition strategy has allowed us to rapidly grow our reserves at favorable acquisition prices. From January 1, 1999, through December 31, 2003, we spent $865.9 million acquiring 190.4 MMBOE of proved oil and gas reserves at an average acquisition cost of $4.55 per BOE. We replaced, through acquisitions, approximately 128 percent of our production of 148.6 MMBOE during the same period. For additional information, see Acquisitions. Although we made no significant acquisitions in 2002 and 2003, primarily as a result of our debt reduction program, we are continually identifying and evaluating acquisition opportunities, including acquisitions that would be significantly larger than many of those we have consummated to date. No assurance can be given that any such acquisitions will be successfully consummated.

Exploration and Development. We pursue workovers, recompletions, secondary recovery operations and other production optimization techniques on our properties, as well as development and infill drilling, with the goals of offsetting normal production declines and replacing our annual production. Our overall exploration strategy balances high potential international prospects with lower risk drilling in known formations in North America and Argentina. We make extensive use of geophysical studies, including 3-D seismic data, which reduces the cost of our exploration program by increasing our success rate. From January 1, 1999, through December 31, 2003, we spent approximately $778.5 million on exploration and development activities. As a result of all of these activities, including the impact of reserve revisions, during the five-year period ended December 31, 2003, we succeeded in adding 192.9 MMBOE to proved reserves, replacing approximately 130 percent of production during the same period at a cost of $4.04 per BOE. During 2003, we spent $181.3 million on exploration and development activities and added 27.0 MMBOE to proved reserves (excluding Canadian additions and revisions), replacing approximately 97 percent of 2003 production at a cost of $6.72 per BOE. Substantial negative net additions and revisions in Canada, however, totaled 26.3 MMBOE, negating almost all of the net additions generated from our operations in other countries. For additional information, see Exploration and Development. We continue to maintain an extensive inventory of exploration and development opportunities. The total 2004 non-acquisition capital budget has been set at $225 million, a 27 percent increase over 2003 spending. The exploration portion of the 2004 capital budget of approximately $60 million will focus primarily on North America, with other projects planned for Yemen, Italy and Bulgaria.

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Efficient Operations. We believe we are an efficient operator and capitalize on our lower cost structure in evaluating acquisition opportunities. We have generally achieved substantial reductions in labor and other field level costs from those experienced by the previous operators. In addition, we target acquisition candidates that are located in our core areas and provide opportunities for cost efficiencies through consolidation with our other operations. The lower cost structure has generally allowed us to substantially improve the cash flows of newly acquired properties.

Financial Flexibility. We are committed to maintaining financial flexibility, which we believe is important for the successful execution of our acquisition, exploitation and exploration strategy. Since 1990, we have completed five public equity offerings, two public debt offerings and three Rule 144A private debt offerings, all of which have provided us with aggregate net proceeds of approximately $1.2 billion. In early 2002 we announced plans to reduce debt by $200 million through a combination of asset sales and cash flows in excess of planned capital expenditures. The sale of our operations in Trinidad and our heavy oil properties in California in 2002, along with our operations in Ecuador in January 2003 and cash flows in excess of our capital expenditures, allowed us to exceed our $200 million debt reduction goal. Our debt, less cash on hand, at December 31, 2003, was $645.1 million, compared to approximately $1.0 billion at December 31, 2001. Cash on hand, internally generated cash flows, the borrowing capacity under our revolving credit facility and our ability to adjust our level of capital expenditures are our major sources of liquidity. In addition, we may use other sources of capital, including the issuance of additional debt securities or equity securities, to fund any major acquisitions we might secure in the future and maintain our financial flexibility. For further information, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity included elsewhere in this Form 10-K.

Acquisitions

Historically, we have allocated a substantial portion of our capital expenditures to the acquisition of producing oil and gas properties. Our continuing emphasis on reserve additions through property acquisitions reflects our belief that consolidation and restructuring activities on the part of major integrated, large independent and national oil companies have afforded in recent years, and should afford in the future, favorable opportunities to purchase domestic and international producing properties.

Since our incorporation in May 1983, we have been actively engaged in the acquisition of producing oil and gas properties, primarily in the West Coast, Gulf Coast, East Texas and Mid-Continent areas of the U.S. In 1995, we made a series of acquisitions that established a new core area in the San Jorge Basin in southern Argentina. In late 1996, we expanded our South American operations into Bolivia and, in 1998, into Ecuador. In 1999, we entered into a farm-in agreement for the S-1 Damis exploration block in Yemen and in December 2000, we made our initial entrance into Canada and Trinidad with the purchase of 100 percent of Cometra Energy (Canada), Ltd. (Cometra), a privately-held Canadian company. We significantly expanded our Canadian operations in 2001 with the purchase of 100 percent of Genesis, a publicly-traded Canadian company. We also extended our Argentine operations in 2000 with our acquisition of two concessions from Perez Companc and in 2001 with our purchase of the La Ventana and Rio Tunuyan concessions from Shell C.A.P.S.A., a wholly-owned affiliate of Royal Dutch Shell. Although we made no significant acquisitions in 2002 and 2003, primarily due to our debt reduction program, we are constantly identifying and evaluating additional acquisition opportunities which may lead to our expansion into new domestic core areas or other countries which we believe are politically and economically stable.

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From January 1, 1999, through December 31, 2003, we made oil and gas reserve acquisitions with costs totaling approximately $865.9 million. As a result of these acquisitions, we acquired approximately 190.4 MMBOE of proved oil and gas reserves. The following table summarizes our acquisition experience during the periods indicated:

	Acquisition Costs	Proved Reserves When Acquired: Oil (MBbls)	Gas (MMcf)	MBOE	Cost Per BOE When Acquired
	(In thousands)				
North America Acquisitions:					
1999	$ 31,662	10,343	14,947	12,834	$ 2.47
2000	53,962	2,854	41,166	9,715	5.55
2001	564,950	27,493	207,701	62,110	9.10
2002					
2003	463	90	258	133	3.48
Total North America Acquisitions	651,037	40,780	264,072	84,792	7.68
South America Acquisitions:					
1999	135,125	67,733	81,072	81,245	1.66
2000	37,486	11,970	2,278	12,350	3.04
2001	42,267	11,724	1,636	11,997	3.52
2002					
2003					
Total South America Acquisitions	214,878	91,427	84,986	105,592	2.03
Total Acquisitions	$ 865,915	132,207	349,058	190,384	$ 4.55

Divestitures

We have historically sold properties that were either marginally economical or non-strategic to our areas of operations. In 2001 and early 2002, we received proceeds of $47.1 million for properties sold primarily through public auctions in the U.S. These sales resulted in gains of $26.9 million ($16.7 million net of tax). Through these sales of 780 wells and over 600 leases in 85 fields, we significantly reduced our domestic well and lease count while reducing net U.S. production by only six percent and total net production by three percent.

In 2002, we determined that the level of investment and time horizon required to continue the development of our interests in Ecuador and Trinidad were inconsistent with the timing of our desire to reduce leverage. These assets, along with our remaining heavy oil properties in the Santa Maria area of southern California, were identified for sale. Our heavy oil properties in the Santa Maria area were sold in June 2002 for $9.5 million in cash and a note receivable for $6 million bearing monthly payments of $360,000, plus interest, with final maturity in June 2003. We received a cash payment as final settlement of this note in October 2002. On July 30, 2002, we completed the sale of our operations in Trinidad. We received $40 million in cash and recorded a gain of approximately $31.9 million ($14.9 million after income taxes).

On January 31, 2003, we completed the sale of our operations in Ecuador. We received $137.4 million in cash and recorded a gain of approximately $47.3 million ($9.5 million after income taxes). Also in 2003, we sold certain U.S. Mid-Continent gas properties for $30.0 million and certain non-strategic oil and gas assets in Saskatchewan and West Central Alberta, Canada for $27.9 million. We recorded losses of $1.7 million ($1.0 million after income taxes) on these sales. Combined, we estimate that the properties we sold in North America in 2003 accounted for proved reserves of 1.0 MMBbls of oil and 53.1 Bcf of gas as of the closing date of the sales and the Ecuador properties accounted for 45.3 MMBbls of oil. In total, these sales represented approximately 10 percent of our total proved reserves at the beginning of 2003.

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Exploration and Development

We concentrate our acquisition efforts on proved producing properties that demonstrate a potential for significant additional development through workovers, recompletions, secondary recovery operations, the drilling of development, infill or exploratory wells and other exploitation opportunities. We have pursued an active workover, recompletion and development drilling program on the properties we have acquired and intend to continue these activities in the future. Our exploitation staff focuses on maximizing the value of the properties within our reserve base and striving to offset normal production declines and our annual production.

Our exploration program is designed to contribute significantly to our growth. We divide the strategic objectives of our exploration program into two parts. First, in North America and Argentina, our exploration focus is in our core areas where our geological and engineering expertise and experience are greatest. We use state-of-the-art technology, including 3-D seismic data, to identify prospects. Exploration in North America is designed to generate reserve growth in this core area in combination with our exploitation activities. In recent years, we have increased the magnitude of this program and we plan to continue this effort in the future with a goal of achieving yearly production replacement through core area exploration. Such exploration is characterized by numerous individual projects with medium to low risk. Secondly, international exploration targets significant long-term reserve growth and value creation. Our international exploration projects currently underway in Yemen, Italy and Bulgaria are characterized by higher potential and higher risk.

In 2003, we spent $22.6 million on workovers, recompletions and other projects. A measure of the overall success of our recompletion and workover operations during 2003 (excluding minor equipment repair and replacement) was that improved production or operating efficiencies were achieved from approximately 77 percent of such operations, which is consistent with the average of 80 percent for the last three years.

Development drilling activity is generated both through our exploration efforts and as a result of obtaining undeveloped acreage in connection with producing property acquisitions. In addition, there are many opportunities for infill drilling on our leases currently producing oil and gas. We intend to continue to pursue development drilling opportunities which offer us potentially significant returns.

During 2003, we participated in the drilling of 124 gross (108 net) development wells, of which 117 gross (102 net) were productive. At December 31, 2003, our proved reserves included approximately 137 development or infill drilling locations on our U.S. acreage, three locations on our Canadian acreage, 463 locations on our Argentine acreage, 13 locations on our Bolivian acreage and six locations on our acreage in Yemen. In addition, we have an extensive inventory of development and infill drilling locations on our existing properties which is not included in proved reserves. Included in our 2003 development drilling was approximately $33.8 million in the U.S., $10.9 million in Canada, $46.5 million in Argentina and $1.0 million in Ecuador. We also spent approximately $6.4 million on the acquisition of development seismic data and other development activities in 2003.

We spent approximately $52.2 million on exploration activities in 2003, participating in the drilling of 12 gross (eight net) exploratory wells, of which six gross (three net) were productive. Exploration spending for 2003 included $36.1 million in North America, $12.4 million in Yemen, $1.4 million in Bulgaria, $1.3 million in Bolivia and $1.0 million in Italy. We also spent approximately $7.8 million on the acquisition of unproved acreage in 2003, primarily in North America.

Our total 2004 non-acquisition capital budget has been set at $225 million, which represents a 24 percent increase over 2003 exploration and development spending. Planned development expenditures for 2004 are $165 million, consisting of $55 million in North America, $84 million in

Argentina and $26 million in Yemen, including $17 million for the start of the construction of facilities near our An Nagyah light oil discovery and a pipeline necessary to connect into neighboring infrastructure. The exploration portion of the 2004 capital budget of approximately $60 million includes $51 million in North America and $9 million on various international projects.

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Exploration and development activities for 2003 were concentrated mainly in our U.S., Canada and Argentina core areas. The following is a brief description of significant developments in our recent exploration and development activities:

United States. We increased our United States oil and gas capital expenditures in 2003, spending a total of $74.5 million, compared to $29.5 million in 2002. Capital expenditures in 2002 were limited as a result of our decision to use a portion of cash flow and proceeds from asset sales to execute our debt reduction program during 2002.

Our U.S. development program for 2003 included the drilling of 31 gross (26 net) development wells, of which 26 gross (23 net) were successful, representing an 84 percent success rate. Exploitation drilling in the West Ranch, Luling and Darst Creek fields in south central Texas resulted in 19 gross (19 net) horizontal completions with an initial production buildup of over 2,700 net Bbls of oil per day. Development drilling in the Gilmer and Loma Blanca fields in Texas and the Strong City field in Oklahoma resulted in three gross (three net) wells with an initial net production buildup of 5.6 MMcf of gas and 200 Bbls of oil per day. High angle drilling of one gross (one net) well in the Pleito Ranch field in California developed an initial net production buildup of 260 Bbls of oil and 100 Mcf of gas per day. Our 2003 U.S. development program also included 80 gross (74 net) workovers and recompletions (excluding minor equipment repair and replacement), of which 55 gross (52 net) resulted in improved production or operating efficiencies, for a 69 percent success rate.

During the fourth quarter of 2003, we drilled the Galveston Bay State Tract 65-2R well, in which we have a 50 percent working interest. This is a replacement well for the State Tract 65-2 which ceased production in June 2003 due to a mechanical problem. The State Tract 65-2R well has been completed and is testing with a daily flow rate of six MMcf gross (three MMcf net) of gas.

Our 2004 development budget includes $46 million targeted towards U.S. projects. We will focus on impact projects along the Texas and Louisiana Gulf Coast, expanding on our successes of 2003 and pursuing new opportunities as well. Several additional horizontal drilling locations are planned in the Darst Creek and Luling fields for 2004. We plan to drill 32 exploitation wells and workovers are planned for approximately 55 wells, principally in Texas and California.

We spent approximately $2.6 million during the fourth quarter of 2003 and returned to production 2,800 BOE per day lost due to the California fires in October 2003. We now estimate that we will complete the remaining fire damage repair at an additional cost of approximately $3.4 million dollars. The volumes from remaining wells are planned to be returned to production by the end of the first quarter of 2004.

We anticipate spending $38 million on our U.S. exploration activities in 2004, focusing our efforts on the Gulf Coast, the Permian basin and California. We are pursuing Oligocene and Miocene exploration prospects that we generated in the Texas Gulf Coast based on 3-D seismic and geochemical surveys. Within these targeted play concepts, we have acquired leases covering four shallow water prospects. Three wells have been successfully drilled on the Tres prospect, High Island #55-L, which was based on a Miocene gas exploration target coupled with the redevelopment of additional Miocene oil and gas sands. Facility and pipeline construction is underway, with initial net daily production estimated to be in the range of 20 to 30 MMcf gross (10 to 15 MMcf net) beginning in mid-2004. We are the operator and have a 65 percent working interest in this prospect. We currently plan to commence drilling on the Wesson prospect, Mustang Island #775, by the third quarter of 2004. The target is a four-way dip anticline with potentially stacked pays at depths from 16,000 to 18,000 feet. We presently own a 100 percent working interest in the Wesson prospect, but we anticipate securing other partners prior to drilling.

We have an interest in over 19,500 gross acres in the Permian basin encompassing three multi-well exploration prospects targeting known tight carbonate gas reservoirs. These prospects are predicated on an established play concept which utilizes horizontal drilling and fracture stimulation technology to significantly improve production and economics over the historical results obtained utilizing vertical well bores. We recently drilled the Wilbanks 53 #2-H in the Rosehill prospect in Martin County, Texas, and the Hannah 17 State #2-H in the Austin prospect in Lea County, New Mexico, with both horizontal wells successfully penetrating the targeted Mississippian formation. The wells are undergoing completion and long-term testing. If these tests are successful, we may drill additional wells on these prospects in 2004. We have a 100 percent working interest in both the Rosehill and Austin prospects.

In California, we are preparing to drill a 12,500 foot oil prospect in the San Joaquin basin. If this prospect is successful, production could commence by the third quarter of 2004 and multiple offset locations could be drilled before year end. We have a 50 percent working interest in this prospect. Further, we plan to spend approximately 15 percent of our domestic exploration budget of $38 million assessing the potential of unconventional resource projects in various locations in the U.S.

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Canada. In 2003, we continued exploitation and exploration activity with the drilling of 32 gross (19 net) wells, of which 26 gross (14 net), or 81 percent, were successful. Drilling in 2003 focused on the Sturgeon Lake, West Central and Peace River Arch operating areas of Alberta and the foothills trend of northeastern British Columbia.

Overall, the results in Canada during 2003 were disappointing, leading to significant downward reserve revisions at year end 2003. Results of our work programs and production performance of certain producing properties during the latter part of 2003 resulted in revisions to reserves previously booked to specific wells or to reserves associated with future activities. Due to these disappointing results, in connection with our normal year end reserve estimation process, we performed a critical review to revise or re-validate all remaining future activities on our Canadian proved reserve base. As a result of this review, we determined that previously planned exploration and development activities would be scaled back or eliminated. We continue to employ independent third party engineering firms to prepare estimates of our reserves in all of our operating areas.

The Sturgeon Lake area exploitation program targeted attic oil accumulations in Devonian age Leduc reef structures and shallow gas accumulations in the Cretaceous Badheart formation. During 2003, 11 gross (9 net) wells were drilled in the area. Results of the 2003 exploitation program were well below expectations resulting in downward revisions in reserves previously booked to specific wells drilled, as well as downward revisions to reserves associated with remaining future activities. No drilling activity is planned in the Sturgeon Lake area for 2004.

In the West Central operating area, we participated in the drilling of eight gross (three net) wells targeting Cretaceous Cardium and Gething gas accumulations in the Oldman and Bigstone areas at an overall success rate of 100 percent. Aggregate initial net daily production from this program was approximately 2.1 MMcf of gas. Additional drilling in this area is scheduled for 2004.

Consistent with the strategy that led to our entry into Canada, we are intensifying our efforts in generating impact exploration prospects within the country. The majority of these prospects will target gas, consistent with our overall business plan to focus our North American exploration endeavor on gas prospects with significant reserve potential. In the Cypress area of northeast British Columbia, we are targeting multi-horizon gas potential in Triassic and Mississippian age thrust features. During 2003 and early 2004, three gross (one net) wells have been drilled with one gross (one net) successful well waiting on a pipeline connection. During 2003, we acquired an additional 25,200 gross (10,775 net) acres in this prospect area. We remain encouraged about the high impact potential in this area and additional drilling is planned for 2004.

We have set our 2004 Canadian exploration and development budget at $22 million. Exploitation spending has been reduced to $9 million in favor of other opportunities we have in other areas. We anticipate drilling 15 gross (7 net) development and extensional wells in Canada with activity concentrated in the West Central and Peace River Arch areas. Exploration spending is budgeted at $13 million with 12 gross (9 net) wells planned in the foothills of northeast British Columbia and the Peace River Arch of Alberta.

Argentina. During 2003, as a result of increased political stability and favorable oil prices, we successfully reinitiated our aggressive growth program in Argentina with a significantly expanded capital budget. Our operational activity, in terms of rigs, reflects the highest activity level since we began operations in Argentina in 1995. As a result of the revitalized campaign, our gross operated oil production in Argentina has now reached 30,000 Bbls per day, the highest level since early 2002. Drilling activity in 2003 increased significantly from one rig operating at the beginning of the year to four rigs operating by the third quarter. We drilled a total of 68 gross (67 net) wells during the year with a success rate of 99 percent. An additional 11 wells were either under completion or in the process of drilling by year end 2003. A similar increase in activity was also seen with the number of workover rigs working, from two rigs at the beginning of 2003 to the current level of seven rigs. We performed a total of 78 gross (73 net) workovers in 2003 with a success rate of 88 percent.

We expect the business outlook for Argentina in 2004 to continue to be favorable and as a result, we anticipate additional production growth from Argentina in 2004. This expectation is supported by a capital budget of $84 million, which is a 44 percent increase over 2003 actual spending. Our 2004 budget includes drilling 92 development wells and performing 84 workovers. Our budget also includes the implementation of four waterflood projects which are targeted to contribute to production in 2005 and beyond.

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Additionally, since our drilling program relies heavily on the interpretation of 3-D seismic data to aid in the optimum placement of wells, we plan to significantly expand our program to record 3-D seismic data for 2004. We believe this will allow us to considerably expand our areas of operations. During 2003, a new 3-D survey in Las Heras and Piedra Clavada was completed with an additional 176 square kilometers (68 square miles) of data recorded. In December 2003 the Cerro Wenceslao seismic program began with 77 square kilometers (30 square miles) of data recorded by the end of 2003 and an additional 137 square kilometers (53 square miles) of data recorded in January 2004.

We have additional 3-D seismic surveys already underway in 2004. We have recorded 139 square kilometers (54 square miles) of data in Canadon Leon and 110 square kilometers (42 square miles) of data in Tres Picos. We have a project underway in Cerro Overo that will cover 171 square kilometers (66 square miles). By the middle of 2004 additional surveys are anticipated to be completed in Block 127 and Canadon Minerales that will cover 78 square kilometers (30 square miles) and 192 square kilometers (74 square miles), respectively. Once these programs are completed, approximately 59 percent of our total acreage in the San Jorge basin will be covered by 3-D seismic data. We also have areas in the Cuyo basin with 29 percent 3-D seismic coverage and the Neuquen basin with no 3-D seismic coverage to date. Upon completion of the 2004 activity in progress, we will have 3-D data covering approximately 51 percent of all of our operated acreage in Argentina.

The number of development drilling locations in Argentina has increased substantially in recent years, from 331 at December 31, 2001, to 463 at December 31, 2003, due to a combination of development drilling and workover results integrated with interpretation of 3-D seismic data.

Bolivia. The focus for our operations in Bolivia continues to be on maximizing gas sales to existing markets and the development of new gas markets. During 2003, we signed two gas sales agreements and continued selling and swapping gas on the spot market. In addition, our only remaining work obligation in Bolivia was completed by performing an aeromagnetic and geochemical study of the Chaco Concession. We do not anticipate any significant capital expenditures in Bolivia during 2004.

Italy. We had originally expected to spud the first of two planned exploration wells in the Po Valley in late 2003. However, due to delays in obtaining the required permits, spudding of the first well has been delayed until the second quarter of 2004. The initial drilling campaign will target shallow gas sands in a stratigraphic trap at a depth of approximately 4,800 feet. The play was defined by 2-D seismic and a geochemical survey. We operate two exploration blocks with a 70 percent working interest. These blocks encompass an area of approximately 275,000 gross acres in the north of Italy which has a well-developed gas market and pipeline infrastructure.

Yemen. On October 15, 2003 the Republic of Yemen s Ministry of Oil and Minerals approved our S-1 Damis block development plan covering 285,000 acres for a term of 20 years. This plan follows the Lam sand discovery made by the An Nagyah #2 well in December 2002, which was further delineated in 2003 with the drilling of the An Nagyah #3 and #4 wells. Operations are currently underway to begin development of the discovery in 2004. We are preparing to commence drilling of the An Nagyah #5 well to appraise the western side of the An Nagyah structure. Following this well, drilling will proceed on the first development well, the An Nagyah #6. In 2004, we plan to drill a total of six wells in Yemen to delineate and develop the An Nagyah structure. In addition to the Lam development, we plan to drill the first appraisal well to the Harmel oil discovery, which was drilled in the 2001 drilling campaign.

We are currently installing early production facilities which will allow production of oil before the central production facility and pipeline are in place. Initial production with the early production facility will be limited to 2,500 Bbls of oil per day (approximately 1,300 Bbls net) and should start late in the first quarter of 2004. Work is underway to design the permanent production facility and pipeline necessary to transport the oil to existing export infrastructure, with construction expected to commence in late 2004. Approximately one-third of our 2004 planned capital expenditures in Yemen of $27 million will be allocated to drilling, with the remainder for the design and construction of production facilities and pipeline.

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Bulgaria. We have been awarded an exploration permit for the Bourgas-Deep Sea block in the exclusive economic zone of the Republic of Bulgaria in the western Black Sea. The permit s initial exploration period expires in December 2005 and has provisions for extension. We have a 100 percent working interest and are the operator of this unexplored block that encompasses nearly two million acres (7,958 square kilometers). We acquired 1,575 kilometers of 2-D seismic data in 2003, which will aid us in the detailed mapping of an identified large structural lead. After completion of additional geological and geophysical work, we expect to secure participation by an industry partner with deep water experience to drill and operate this prospect.

Oil and Gas Properties

At December 31, 2003, we owned and operated domestic producing properties in nine states, with our U.S. proved reserves located primarily in four core areas: West Coast, Gulf Coast, East Texas and Mid-Continent. In addition, we established core areas in Argentina during 1995, Bolivia during 1996 and Canada in 2000. As of December 31, 2003, we operated 4,111gross (3,913 net) productive wells and also owned non-operating interests in 729 gross (216 net) productive wells. We continuously evaluate the profitability of our oil, gas and related activities and we have a policy of divesting ourselves of unprofitable leases or areas of operations that are not consistent with our operating philosophy. See Divestitures.

The following table sets forth estimates of our proved oil and gas reserves at December 31, 2003, as estimated by the independent petroleum consultants of Netherland, Sewell & Associates, Inc. for the U.S., Argentina and Yemen, as estimated by the independent petroleum consultants of DeGolyer and MacNaughton for Bolivia and as estimated by the independent petroleum consultants of Outtrim Szabo Associates Ltd. for Canada:

	Oil (MBbls)			Gas (MMcf)			MBOE
	Developed	Undeveloped	Total	Developed	Undeveloped	Total	Total
West Coast	48,171	4,331	52,502	92,391	4,198	96,589	68,600
Gulf Coast	20,777	6,591	27,368	60,518	37,045	97,563	43,629
East Texas	5,950	730	6,680	61,141	16,011	77,152	19,539
Mid-Continent	647	407	1,054	14,385	1,842	16,227	3,758
Total U.S.	75,545	12,059	87,604	228,435	59,096	287,531	135,526
Canada	3,462	34	3,496	66,433	304	66,737	14,619
Total North America	79,007	12,093	91,100	294,868	59,400	354,268	150,145
Argentina	103,973	88,545	192,518	35,645	87,642	123,287	213,066
Bolivia	5,632	411	6,043	384,393	64,090	448,483	80,790
Yemen		3,137	3,137				3,137
Total Company	188,612	104,186	292,798	714,906	211,132	926,038	447,138

Estimates of our 2003 proved reserves set forth above have not been filed with, or included in reports to, any federal authority or agency, other than the Securities and Exchange Commission.

Proved reserves at December 31, 2003, include 46.0 MMBbls of oil and 13.3 Bcf of gas (48.2 MMBOE) related to the ten year extension periods contained in our Argentina concession agreements. Proved developed reserves at December 31, 2003, include 22.6 MMBls of oil and 0.4 Bcf of gas (22.7 MMBOE) related to these extension periods. Upon approval by the government, the extension periods begin in 2015 through 2017, depending on the effective date each concession agreement was granted. We believe, based on historical precedent, that such extensions will be obtained as a matter of course.

Our proved developed non-producing reserves are largely concentrated behind-pipe in fields which we operate. Proved undeveloped reserves are predominantly concentrated in development drilling locations and secondary recovery projects, most of which we operate.

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The following is a brief discussion of our oil and gas operations in our core areas:

West Coast Area. The West Coast area includes oil and gas properties located primarily in Kern and Ventura counties and the Sacramento Basin of California. The Stevens, Forbes and Grubb formations are the dominant producing reservoirs on our acreage in California with well depths ranging from 800 feet to 14,300 feet. As of December 31, 2003, the area comprised 15 percent of our total proved reserves and 51 percent of our U.S. proved reserves. We currently operate 1,209 gross (1,179 net) productive wells in this area and we own an interest in 95 gross (seven net) productive wells operated by others. During 2003, net daily production for this area averaged approximately 11,400 BOE, or 41 percent of our total net daily U.S. production. Numerous workovers and recompletion opportunities exist in the San Miguelito and Rincon fields. Additional infill drilling locations are available in the San Miguelito, Pleito Ranch, and Tejon fields. The San Miguelito field also has waterflood potential that may add significant reserves and the Antelope Hills field has oil reserves that may be added through expansions of our steamflood project.

Gulf Coast Area. The Gulf Coast area includes properties located in southern Texas, the southern half of Louisiana, Alabama, Mississippi and wells located in shallow state and federal waters. The reservoirs in the coastal waters and federal waters range in age from Pliocene to middle and upper Miocene and Oligocene. Reservoirs further onshore are predominantly from Eocene and Cretaceous ages. The depths of the producing reservoirs range from 1,200 feet to 14,500 feet. At December 31, 2003, the Gulf Coast area comprised approximately 10 percent of our total proved reserves and 32 percent of our U.S. proved reserves. We currently operate 651 gross (636 net) productive wells in this area and we own an additional interest in 26 gross (nine net) productive wells operated by others. During 2003, net daily production from this area averaged approximately 10,600 BOE, or 39 percent of our total net daily U.S. production. A significant inventory of workovers and recompletions exists in Gulf Coast fields from Alabama to south Texas. Development drilling potential is also available in various fields in Texas and Louisiana.

East Texas Area. The East Texas area includes properties located in the northeastern portion of Texas and the northern half of Louisiana. The Cotton Valley, Smackover and Travis Peak formations are the dominant producing reservoirs on our acreage in this area with wells ranging in depth from 1,300 feet to 14,800 feet. The East Texas area comprised approximately four percent of our December 31, 2003, total proved reserves and 14 percent of our U.S. proved reserves. We currently operate 520 gross (450 net) productive wells in this area and we own an interest in an additional 30 gross (four net) productive wells operated by others. During 2003, net daily production for this area averaged approximately 4,500 BOE, or 16 percent of our total net daily U.S. production. Significant infill drilling potential exists on our acreage in the South Gilmer and Southern Pine fields.

Mid-Continent Area. The Mid-Continent area extends from the Arkoma Basin of eastern Oklahoma to the Texas panhandle and north to include Kansas. The Red Fork, Morrow, Skinner and Hoxbar formations are the dominant producing reservoirs on our acreage in this area with well depths ranging from 1,560 feet to 17,260 feet. This area comprised one percent of our December 31, 2003, total proved reserves and three percent of our U.S. proved reserves. We currently operate 65 gross (30 net) productive wells in this area and we own an interest in an additional 64 gross (eight net) productive wells operated by others. During 2003, net daily production for this area averaged approximately 1,100 BOE, or four percent of our total net daily U.S. production. Projects to improve the ultimate reserve recovery exist in the Shawnee Townsite waterflood. Significant production response was observed in our Missouri Flats waterflood project during 2003 as we anticipated.

Canada. Our Canadian producing properties are located in the provinces of Alberta, Saskatchewan and British Columbia. We also have approximately 1.5 million net undeveloped acres located in Canada. The Canadian properties comprised approximately three percent of our December 31, 2003, total proved reserves. We currently operate 371 gross (323 net) productive wells in Canada and we own interests in 274 gross (96 net) wells operated by others. During 2003, net daily production averaged approximately 3,400 Bbls of oil and 52.5 MMcf of gas.

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Argentina. Our Argentine properties consist primarily of 14 mature producing concessions located on the south flank of the San Jorge Basin, all of which we operate, four concessions located in the Cuyo Basin in western Argentina, two of which we operate, and three concessions in the Neuquen Basin, two of which we operate. These concessions comprised approximately 48 percent of our December 31, 2003, total proved reserves. During 2003, net daily production averaged approximately 28,500 Bbls of oil and 27.0 MMcf of gas. We currently operate 1,278 gross (1,278 net) productive wells. In addition, we own an interest in 240 gross (93 net) productive wells operated by others. At December 31, 2003, our proved reserves included approximately 463 development drilling locations on our Argentine acreage. In addition, we have an extensive inventory of workovers and development or infill drilling locations on our Argentine properties which are not included in proved reserves.

Bolivia. Our Bolivian properties consist of four producing concessions located in the Chaco Basin of Bolivia. We have a 100 percent working interest in the Naranjillos, Chaco Sur and Porvenir producing concessions. In the other producing concession, Nupuco, we have a 50 percent working interest. We operate all four producing concessions. These concessions comprise approximately 18 percent of our December 31, 2003, total proved reserves and include 14 gross (13 net) productive wells. Net daily production during 2003 averaged approximately 17.1 MMcf of gas and 225 Bbls of condensate. Current net daily productive capacity of our properties in Bolivia is approximately 46 MMcf of gas and 690 Bbls of condensate. We are working to develop additional gas markets, both inside and outside of Bolivia, to increase the level of production from our concessions.

Marketing

Generally, our U.S. oil production is sold under short-term contracts at posted prices, plus a premium in some cases, or at NYMEX prices less a specified differential. Our Canadian oil production is sold under short-term contracts at posted prices. Our Argentine oil production is currently sold at port to Esso S.A.P.A. (the Argentine affiliate of Exxon-Mobil), ENAP (the Chilean government-owned oil company) and Chevron-Texaco Corp. at West Texas Intermediate spot prices as quoted on the Platt s Crude Oil Marketwire (approximately equal to the NYMEX reference price) less a specified differential. During 2003, approximately 16 percent of our total revenues related to oil sales to ENAP.

In January 2002, the Argentine government devalued the Argentine peso (peso) and enacted an emergency law that, in part, required certain contracts that were previously payable in U.S. dollars to be payable in pesos. Subsequently, on February 13, 2002, the Argentine government announced a 20 percent tax on oil exports, effective March 1, 2002. The tax is limited by law to a term of no more than five years. The tax of 20 percent is applied on the sales value after the tax, thus the net effect is 16.7 percent. The export tax is not deducted in the calculation of royalty payments. For additional information, see Item 7A. Quantitative and Qualitative Disclosures About Market Risk Foreign Currency and Operations Risk included elsewhere in this From 10-K. Domestic Argentine oil sales, while valued in U.S. dollars, are now being paid in pesos. Export oil sales continue to be valued and paid in U.S. dollars.

We currently export approximately 45 percent of our Argentine oil production; however, in 2003 we exported approximately 60 percent. We believe that the export tax will have the effect of decreasing all future Argentine oil revenues (not only export revenues) by as much as the tax rate for the duration of the tax. The U.S. dollar equivalent value for domestic Argentine oil sales (now paid in pesos) has generally moved toward parity with the U.S. dollar denominated export values, net of the export tax. The adverse impact of this tax has been partially offset by the net cost savings resulting from the devaluation of the peso on peso denominated costs and is further reduced by the Argentine income tax savings related to deducting the impact of the export tax.

On January 2, 2003, at the Argentine government s request, crude oil producers and refiners agreed to cap amounts payable for certain domestic sales occurring during the first quarter 2003 at $28.50 per Bbl. The producers and refiners further agreed that the difference between the actual price and the capped price would be payable once actual prices fall below the cap. The debt payable under the original agreement accrues interest at eight percent. The total debt will be collected by invoicing future deliveries at $28.50 per Bbl after actual prices fall below the capped price. Additionally, the agreement allowed for renegotiation if the West Texas Intermediate reference price exceeded $35.00 per Bbl for 10 consecutive days, which occurred on February 24, 2003.

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On February 25, 2003, the agreement between the producers and the refiners was modified to limit the amount payable from refiners to producers for deliveries occurring between February 26, 2003, and March 31, 2003. While the $28.50 per Bbl payable cap was maintained, under the modified terms refiners have no obligation to pay producers for sales values that exceed $36.00 per Bbl. Furthermore, interest for debts established during this period was reduced to seven percent. Substantially in this form, the agreement has been extended through February 2004. An additional two-month extension is expected to occur in the near future.

We sold approximately 1.4 MMBbls of our net Argentine oil production (approximately 14 percent) under this agreement in 2003. We have not recorded revenue nor a receivable for any amounts above the $28.50 per Bbl maximum that have not yet been received. Repayments received from refiners will be recorded as revenues when received.

Our U.S. and Canada gas production and gathered gas are generally sold on the spot market or under market-sensitive, long-term agreements with a variety of purchasers, including intrastate and interstate pipelines, their marketing affiliates, independent marketing companies and other purchasers who have the ability to move the gas under firm transportation agreements. Because very little of our North American gas is committed to long-term fixed-price contracts, we are positioned to take advantage of future strong gas price environments, but we are also subject to any future gas price declines. Most of our Bolivian gas production is sold at average gas prices tied to a long-term contract under which the base price is adjusted for changes in specified fuel oil indexes. Our Argentine gas is sold under spot contracts of varying lengths and, as a result of the emergency law enacted in January 2002, these contracts are now paid in pesos. This has resulted in a decrease in sales revenue value when converted to U.S. dollars due to the devaluation of the peso and current market conditions. This value is improving over time as domestic Argentine gas drilling declines and market conditions improve.

Our U.S. gas marketing activities are handled by Vintage Gas, Inc., our wholly-owned gas marketing affiliate. This marketing affiliate earns fees through the marketing of gas we produce as well as purchases of gas on the spot market from third parties. Generally, the marketing affiliate purchases this gas on a month-to-month basis at a percentage of resale prices.

We have entered into certain firm gas transportation and compression agreements in Canada and Bolivia whereby we have committed to transport and compress certain volumes of gas at established government-regulated fees. While these fees are not fixed, they are government-regulated and therefore, we believe the risk of significant fluctuations is minimal. We entered into these arrangements to ensure our access to gas markets and we currently expect to produce sufficient volumes to utilize all of the contracted transportation and compression capacity under these arrangements. Based on the current fee level, these commitments total approximately $2.4 million in 2004, $0.9 million in 2005, $0.6 million in 2006, $0.4 million in 2007 and $0.3 million in each of the years 2008 and 2009.

We have also entered into deliver-or-pay arrangements where we have committed to deliver certain volumes of gas to third parties in Bolivia and Argentina for a specified period of time. These volumes will be sold at market prices. If the required volumes are not delivered, we must pay for the undelivered volumes at the then-current market price. Similar to the firm transportation and compression agreements, we entered into these arrangements to ensure our access to gas markets and we currently expect to produce sufficient volumes to satisfy all of our deliver-or-pay obligations. The volumes contracted under the agreement in Bolivia are 10.3 Bcf in 2004, 6.0 Bcf in 2005, 5.8 Bcf in 2006, 6.0 Bcf in 2007, 6.9 Bcf in 2008 and 6.9 Bcf in 2009. The volumes contracted under the agreement in Argentina are 5.8 Bcf in 2004, 3.8 Bcf in 2005, 3.3 Bcf in 2006, 3.6 Bcf in 2007 and 3.9 Bcf in 2008.

In Canada, we have entered into certain firm gas gathering and processing agreements whereby we have committed to process certain volumes of gas at a monthly capital fee based on a sliding scale and to pay our proportionate share of the plant operating costs based on our share of the total volumes processed through the plant. The volumes under these agreements total 2.3 MMcf per day in 2004 and 2.0 MMcf per day for the first six months of 2005.

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We have previously engaged in oil and gas hedging activities and we intend to continue to consider various hedging arrangements to realize commodity prices which we consider favorable. We have entered into various oil hedges (swap agreements) covering approximately 6.7 MMBbls at a weighted average price of $28.77 per Bbl (NYMEX reference price) for various periods of 2004 and 2005. We continue to monitor oil and gas prices and we may enter into additional oil and gas hedges or swaps in the future.

The following table reflects the Bbls hedged and the corresponding weighted average NYMEX reference prices by quarter:

Quarter Ending	Bbls	NYMEX Reference Price Per Bbl
March 31, 2004	1,410,500	$ 29.77
June 30, 2004	1,456,000	29.67
September 30, 2004	1,324,800	29.48
December 31, 2004	1,135,700	29.26
March 31, 2005	323,700	26.23
June 30, 2005	342,800	25.76
September 30, 2005	355,700	25.52
December 31, 2005	361,900	25.45

The counterparties to our current swap agreements are commercial or investment banks.

Gathering Systems and Plant

We own 100 percent interests in seven oil and gas gathering systems located in California, Kansas, Oklahoma and Texas. We operate all of these gathering systems. Together, these systems comprise approximately 115 miles of varying diameter pipe. Generally, the gathering systems transport oil and gas for various third parties, as well as for us, for a fee under contracts containing terms of one to ten years. However, at certain locations the gathering systems buy gas at the wellhead on the basis of a percentage of the resale price.

Our Santa Clara Valley gas plant is located in Ventura County, California and is a cryogenic expander plant designed for 17 MMcf per day of inlet gas. The plant is currently processing approximately nine MMcf of gas per day and producing approximately 27,000 gallons per day of natural gas liquids (butane-propane). The natural gas liquids are trucked from the plant for sale and the approximate split is 30 percent gasoline and 70 percent butane-propane mix. Gas is purchased from various third parties, as well as from us, primarily under wellhead gas purchase agreements.

In 2003, we constructed a carbon dioxide treating facility at our Shiells Canyon property in Ventura, California. This treater is designed to treat up to 7 MMcf per day of gas and deliver the treated gas volumes to the Santa Clara Valley gas plant for processing and residue re-delivery. We are currently processing 5.6 MMcf per day of both our gas and gas from third parties through the treater. The installation of the treater has allowed us to significantly increase the inlet volumes and the cash flow of the Santa Clara Valley gas plant.

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Reserves

At December 31, 2003, we had proved reserves of 447.1 MMBOE, comprised of 292.8 MMBbls of oil and 926.0 MMcf of gas, as estimated by the independent petroleum consultants of Netherland, Sewell & Associates, Inc. for the U.S., Argentina and Yemen, as estimated by the independent petroleum consultants of DeGolyer and MacNaughton for Bolivia and as estimated by the independent petroleum consultants of Outtrim Szabo Associates Ltd. for Canada. No reserve estimates have been filed with any federal authority or agency other than the SEC. For additional information on our oil and gas reserves, see Oil and Gas Properties. The following table sets forth, at December 31, 2003, the present value of future net revenues (revenues less production, development and abandonment costs) before income taxes attributable to our proved reserves at such date (in thousands):

Proved Reserves:	
Future net revenues before income taxes	$ 6,587,724
Present value of future net revenues before income taxes, discounted at 10 percent	3,507,673
Standardized measure of discounted future net cash flows	2,382,528
Proved Developed Reserves:	
Future net revenues before income taxes	$ 4,286,397
Present value of future net revenues before income taxes, discounted at 10 percent	2,454,656

In computing this data, assumptions and estimates have been utilized, and we caution against viewing this information as a forecast of future economic conditions. The estimated future net revenues are determined by using estimated quantities of proved reserves and the periods in which they are expected to be developed and produced based on December 31, 2003, economic conditions. The estimated future production is valued at prices prevailing at December 31, 2003. The resulting estimated future gross revenues are reduced by estimated future costs to develop and produce the proved reserves based on December 31, 2003, cost levels, but such costs do not include debt service, general corporate overhead expenses and income taxes.

Our proved reserves include amounts related to the 10 year extension periods contained in our Argentina concession agreements. Upon approval by the government, the extension periods begin in 2015 through 2017, depending on the effective date each concession agreement was granted. We believe, based on historical precedent, that such extensions will be obtained as a matter of course. The extension period reserves at December 31, 2003, consisted of 46.0 MMBbls of oil and 13.3 Bcf of gas (48.2 MMBOE). The proved reserves related to the extension periods represented $703.6 million of our future net revenues before income taxes, $165.5 million of our present value of future net revenues before income taxes, discounted at 10 percent and $92.6 million of our standardized measure of discounted future net cash flows. The proved developed reserves related to the extension periods represented $202.7 million of our future net revenues before income taxes and $48.5 million of our present value of future net revenues before income taxes, discounted at 10 percent.

For additional information concerning the historical discounted future net revenues to be derived from these reserves and the disclosure of the Standardized Measure information in accordance with the provisions of Statement of Financial Accounting Standards No. 69, *Disclosures about Oil and Gas Producing Activities*, see Note 13 Supplementary Financial Information for Oil and Gas Producing Activities to our consolidated financial statements included elsewhere in this Form 10-K.

The reserve data set forth in this Form 10-K represent estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. 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 estimate. Accordingly, reserve estimates often differ from the quantities of oil and gas that are ultimately recovered. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they were based.

For further information on reserves, costs relating to oil and gas activities and results of operations from producing activities, see Note 13 Supplementary Financial Information for Oil and Gas Producing Activities to our consolidated financial statements included elsewhere in this Form 10-K.

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Productive Wells; Developed Acreage

The following table sets forth our productive wells and developed acreage assignable to such wells at December 31, 2003:

	Developed Acreage		Productive Wells					
			Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
U.S.	451,768	329,481	2,137	1,966	523	357	2,660	2,323
Canada	374,375	183,064	197	141	448	278	645	419
Argentina	217,848	181,894	1,499	1,352	19	19	1,518	1,371
Bolivia	76,603	65,483			14	13	14	13
Yemen	285,654	214,240	3	2			3	2
Total	1,406,248	974,162	3,836	3,461	1,004	667	4,840	4,128

Productive wells consist of producing wells and wells capable of production, including gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Wells which are completed in more than one producing horizon are counted as one well.

Undeveloped Acreage

At December 31, 2003, we held the following undeveloped acres located in the U.S., Canada, Argentina, Italy and Bulgaria.

State/Country	Gross Acres	Net Acres
California	3,108	3,067
Louisiana	1,611	672
New Mexico	3,122	2,636
North Dakota	1,465	453
Oklahoma	4,026	1,512
Texas	27,265	20,502
Total U.S.	40,597	28,842
Canada	2,368,910	1,524,593

Argentina	1,267,183	1,065,486
Italy	275,107	192,575
Bulgaria	1,966,464	1,966,464
Total Company	5,918,261	4,777,960

With respect to such U.S. acreage held under leases, 29,797 gross (18,670 net) acres are held under leases with primary terms that expire at varying dates through December 31, 2007, unless commercial production has commenced. With respect to such Canadian acreage held under leases, 1,621,915 gross (1,024,103 net) acres are held under leases with primary terms that expire at varying dates through December 31, 2007, unless commercial production has commenced, the leases are validated by the drilling of a well or the leases are continued on the basis of geological evidence. We have the option to relinquish portions of our undeveloped acreage in Argentina at various dates through 2007 or pay increased lease rentals. Our acreage in Italy is held under exploration concessions that expire on March 31, 2007, unless commercial quantities of hydrocarbons are found and the concessions are converted to production concessions, which have a 30 year term. We can extend the term of the exploration concessions two times for a period of three years each time. However, each time an exploration concession is extended, we must relinquish 25 percent of its area. Our acreage in Bulgaria is held under our exploration permit, which expires in December 2005, with provisions for extension.

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Production; Unit Prices; Costs

The following table sets forth information with respect to production, average unit prices and costs for the periods indicated:

	Years Ended December 31,		
	2003	2002	2001
Production:			
Oil (MBbls) -			
U.S.	6,199	6,796	8,409
Canada	1,248	1,829	1,539
Argentina [a]	10,388	10,942	10,548
Bolivia [b]	83	118	101
Continuing operations	17,918	19,685	20,597
Ecuador [c]	114	1,174	1,375
Trinidad			2
Total	18,032	20,859	21,974
Gas (MMcf) -			
U.S.	23,097	24,841	34,168
Canada	19,153	29,951	22,132
Argentina	9,838	8,630	10,253
Bolivia	6,252	6,424	9,088
Total	58,340	69,846	75,641
MBOE from continuing operations	27,641	31,326	33,204
Total MBOE	27,755	32,500	34,581
Average Sales Price (including impact of hedges):			
Oil (per Bbl) -			
U.S.	$ 24.98	$ 21.78	$ 23.08
Canada	28.18	21.62	20.55
Argentina	26.14	20.98(d)	21.80
Bolivia	23.04	20.73	20.06
Continuing operations	25.87	21.31(d)	22.22
Ecuador	26.87	20.46	17.65
Total	25.88	21.27(d)	21.93
Gas (per Mcf) -			
U.S.	$ 4.20	$ 2.85	$ 4.83
Canada	4.35	2.48	2.50
Argentina	0.46	0.37	1.30
Bolivia	2.01	1.54	1.72
Total	3.38	2.26	3.30
Average Sales Price (excluding impact of hedges):			
Oil (per Bbl) -			
U.S.	$ 28.23	$ 22.66	$ 22.17
Canada	27.90	21.62	20.55
Argentina	26.14	21.06(d)	20.66
Bolivia	23.04	20.73	20.06
Continuing operations	26.98	21.66(d)	21.27
Ecuador	26.87	20.46	17.65
Total	26.98	21.60(d)	21.04

Gas (per Mcf) -			
U.S.	$ 4.81	$ 2.94	$ 4.83
Canada	4.67	2.49	2.50
Argentina	0.46	0.37	1.30
Bolivia	2.01	1.54	1.72
Total	3.73	2.30	3.30

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	Years Ended December 31,		
	2003	**2002**	**2001**
Production Costs (per BOE):			
U.S.	$ 9.16	$ 8.05	$ 7.56
Canada	8.91	6.61	6.23
Argentina	6.96	5.40	4.98
Bolivia	4.01	3.64	2.71
Continuing operations	7.95	6.52	6.16
Ecuador	6.50	7.68	6.47
Total	7.95	6.56	6.18

(a) Production for Argentina for the years ended December 31, 2003, 2002 and 2001, before the impact of changes in inventories was 10,273 MBbls, 10,771 MBbls, and 10,644 MBbls, respectively.

(b) Production for Bolivia for the years ended December 31, 2003, 2002 and 2001, before the impact of changes in inventories was 83 MBbls, 95 MBbls and 125 MBbls, respectively.

(c) Production for Ecuador for the years ended December 31, 2003, 2002 and 2001, before the impact of changes in inventories was 114 MBbls, 1,191 MBbls and 1,375 MBbls, respectively.

(d) Reflects the impact of the one-time government-mandated forced settlement of domestic Argentine oil sales which decreased the amounts for Argentina, total continuing operations and total average oil prices per Bbl for the year ended December 31, 2002, by $0.73, $0.41 and $0.38, respectively.

The components of production costs may vary substantially among wells depending on the methods of recovery employed and other factors, but generally include export taxes, production taxes, ad valorem taxes, transportation and storage costs, maintenance and repairs, labor and utilities.

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Drilling Activity

During the periods indicated, we drilled or participated in the drilling of the following exploratory and development wells:

	Years Ended December 31,					
	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Development:						
United States -						
Productive	26	22.71	2	1.42	16	7.40
Non-Productive	5	3.64			2	1.45
Canada -						
Productive	24	13.40	39	28.70	47	33.40
Non-Productive	1	1.00	10	8.40	7	6.80
Argentina -						
Productive	67	65.80	20	18.00	68	68.00
Non-Productive	1	1.00			1	1.00
Ecuador -						
Productive			3	2.15	1	0.75
Non-Productive						
Total	124	107.55	74	58.67	142	118.80
Exploratory:						
United States -						
Productive	1	.33	1	.35	7	4.44
Non-Productive	1	.42	1	.25	4	2.53
Canada -						
Productive	2	.70	17	13.60	26	20.00
Non-Productive	5	4.00	19	18.20	10	8.90
Yemen -						
Productive	3	2.25	1	.75		
Non-Productive			1	.75		
Trinidad -						
Productive					2	0.72
Non-Productive						
Total	12	7.70	40	33.90	49	36.59
Total:						
Productive	123	105.19	83	64.97	167	134.71
Non-Productive	13	10.06	31	27.60	24	20.68
Total	136	115.25	114	92.57	191	155.39

The above well information excludes wells in which we have only a royalty interest.

At December 31, 2003, we were a participant in the drilling, completion or evaluation of 34 gross (23 net) wells. All of our drilling activities are conducted with independent contractors. We do not own any drilling equipment.

Seasonality

Historically, our results of operations are somewhat seasonal due to seasonal fluctuations in the price for gas with gas prices having been generally higher in the winter months. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of results which may be realized on an annual basis. The production of natural gas is generally not directly affected by seasonal swings in demand, except in Argentina and Bolivia. However, we may decide during periods of low commodity prices to decrease development activity, which can result in decreased gas production volumes. Production of oil usually is not affected by seasonal swings in demand or in market prices.

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Competition

Competition in the oil and gas industry is intense. In seeking to acquire desirable producing properties, new leases and exploration prospects and in marketing oil and gas, we face competition from both major and independent oil and gas companies, as well as from numerous individuals and drilling programs. Many of these competitors have financial and other resources substantially in excess of those available to us. Alternative fuel sources also present competition.

Exploration for and production of oil and gas are affected by the availability of pipe, casing and other tubular goods and certain other oilfield equipment, including drilling rigs and tools. We are dependent upon independent drilling contractors to furnish rigs, equipment and tools to drill the wells we operate. We have not experienced and do not anticipate difficulty in obtaining supplies, materials, equipment or tools. If higher prices for oil and gas production are accompanied by increased oilfield activity, increased competition for these items as well as for drilling and workover rigs, in particular, may result in increased costs of operations, which could impact the timing of our planned projects.

Regulation

Domestic Operations. The domestic oil and gas industry is extensively regulated by federal, state and local authorities. Legislation affecting the oil and gas industry is under constant review for amendment or expansion. Numerous departments and agencies, both federal and state, have issued rules and regulations affecting the oil and gas industry and its individual members, some of which carry substantial penalties for non-compliance. The regulatory burden on the oil and gas industry increases its cost of doing business and, consequently, affects its profitability. Inasmuch as such laws and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such regulations.

Our exploration and production are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandoning of wells. Our operations are also subject to various conservation regulations, including regulation of the size of drilling and spacing units or proration units, the density of wells which may be drilled and the unitization or pooling of oil and gas properties. In this regard, some states allow the forced pooling or integration of land and leases to facilitate exploration, while other states rely on voluntary pooling of land and leases. In addition, state conservation laws establish maximum, quarterly and/or daily allowable rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose certain requirements regarding the ratability of production. The effect of these regulations is to limit the amounts of oil and gas we can produce from our wells and the number of wells or the locations at which we can drill.

Various federal, state and local laws and regulations covering the discharge of materials into the environment, or otherwise relating to the protection of the environment, may affect our exploration, development and production operations. For example, the discharge or substantial threat of a discharge of oil by us into U.S. waters or onto an adjoining shoreline may subject us to liability under the Oil Pollution Act of 1990 and similar state laws. While liability under the Oil Pollution Act of 1990 is limited under certain circumstances, such limits are so high that the maximum liability would likely have a significant adverse effect on us. Our operations generally will be covered by insurance which we believe is adequate for these purposes. However, there can be no assurance that such insurance coverage will always be in force or that, if in force, it will adequately cover any losses or liabilities we may incur. We are also subject to laws and regulations concerning occupational safety and health. It is not anticipated that we will be required in the near future to expend any amounts that are material in the aggregate to our overall operations by reason of environmental or occupational safety and health laws and regulations, but because such laws and regulations are frequently changed, we are unable to predict the ultimate cost of compliance.

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Certain of our oil and gas leases are granted by the federal government and administered by various federal agencies. Such leases require compliance with detailed federal regulations and orders which regulate, among other matters, drilling and operations on these leases and calculation of royalty payments to the federal government. The Mineral Lands Leasing Act of 1920 places limitations on the number of acres under federal leases that may be owned in any one state. While subject to this law, we do not have a substantial federal lease acreage position in any state or in the aggregate. The Mineral Lands Leasing Act of 1920 and related regulations also may restrict a corporation from holding a federal onshore oil and gas lease if stock of such corporation is owned by citizens of foreign countries which are not deemed reciprocal under such Act. Reciprocity depends, in large part, on whether the laws of the foreign jurisdiction discriminate against a U.S. person s ownership of rights to minerals in such jurisdiction. The purchase of our shares by citizens of foreign countries who are not deemed to be reciprocal under such Act could have an impact on our ownership of federal leases.

Federal legislation and regulatory controls have historically affected the price of the gas we produce and sell and the manner in which our production is marketed. Historically, the transportation and sale for resale of gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938 (the NGA), the Natural Gas Policy Act of 1978 (the NGPA) and the regulations promulgated thereunder by the Federal Energy Regulatory Commission (the FERC). The Natural Gas Wellhead Decontrol Act of 1989 amended the NGPA to remove, as of January 1, 1993, the remaining natural gas wellhead pricing, sales, certificate and abandonment regulation of first sales that had been regulated by the FERC.

Commencing in 1985, the FERC, through Order Nos. 436, 500, 636 and 637, promulgated changes that significantly affect the transportation and marketing of gas. These changes have been intended to foster competition in the gas industry by, among other things, inducing or mandating that interstate pipeline companies provide nondiscriminatory transportation services to producers, distributors, buyers and sellers of gas and other shippers (so-called open access requirements). The FERC has also sought to expedite the certification process for new services, facilities, and operations of those pipeline companies providing open access services.

In 1992, the FERC issued Order 636. Among other things, Order 636 required each interstate pipeline company to unbundle its traditional wholesale services and create and make available on an open and nondiscriminatory basis numerous constituent services (such as gathering services, storage services, firm and interruptible transportation services, and stand-by sales services) and to adopt a new rate-making methodology to determine appropriate rates for those services. Each pipeline company was required to develop the specific terms of service in individual proceedings. Although the regulations do not directly regulate gas producers such as us, the availability of non-discriminatory transportation services and the ability of pipeline customers to modify or terminate their existing purchase obligations under these regulations have greatly enhanced the ability of producers to market their gas directly to end users and local distribution companies. In this regard, access to markets through interstate gas pipelines is critical to our marketing activities.

In 2000, the FERC issued Order 637 to make short-term capacity release more viable and to foster a more competitive and transparent market in which prices are more efficient. Among other things, Order 637 removes the price cap on short-term capacity releases, allows peak/off peak rates for short-term services to better reflect seasonal market demands and permits pipelines to propose term-differentiated rates to better reflect the underlying contracting risks of both pipelines and shippers.

The FERC has issued a new policy regarding the use of nontraditional methods of setting rates for interstate gas pipelines in certain circumstances as alternatives to cost-of-service based rates. A number of pipelines have obtained FERC authorization to charge negotiated rates as one such alternative.

Under the NGA, gas gathering facilities are generally exempt from FERC jurisdiction. On the other hand, interstate transmission facilities are subject to FERC jurisdiction. The FERC has historically distinguished between these types of activities on a very fact-specific basis which makes it difficult to predict with certainty the status of our gathering facilities. While the FERC has not issued any order or opinion declaring our facilities as gathering rather than transmission facilities, we believe that these systems meet the traditional tests that the FERC has used to establish a pipeline s status as a gatherer. As a result of the FERC s decision to allow a number of interstate pipelines to spin-off gathering systems and thereby exempt them from federal regulation, some states enacted and others continually consider statutory and/or regulatory provisions to regulate gathering systems. Our gathering systems could be adversely affected should they be subjected in the future to the application of such state regulation.

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With respect to oil pipeline rates subject to the FERC s jurisdiction, in October 1993, the FERC issued Order 561 to fulfill the requirements of Title XVIII of the Energy Policy Act of 1992. Order 561 established an indexing system, effective January 1, 1995, under which most oil pipelines will be able to readily change their rates to track changes in the Producer Price Index for Finished Goods (PPI-FG), minus one percent. This index established ceiling levels for rates. Order 561 also permits cost-of-service proceedings to establish just and reasonable rates. The order does not alter the right of a pipeline to seek FERC authorization to charge market-based rates. However, until the FERC makes the finding that the pipeline does not exercise significant market power, the pipeline s rates cannot exceed the applicable index ceiling level or a level justified by the pipeline s cost of service.

Foreign Operations. Our operations in Argentina are subject to the laws and regulations of the country. Beginning in December 2001, new measures have been enacted by law and executive order that may materially impact, among other items, (i) the realized prices we receive for oil and gas we produce and sell; (ii) the timing and amount of repatriations of cash to the U.S.; (iii) the amount of permitted export sales; (iv) the Argentine banking system; (v) our asset valuations; and (vi) peso-denominated monetary assets and liabilities. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Foreign Currency and Operations Risk.

Our operations in Canada, Bolivia, Yemen, Italy and Bulgaria are subject to various laws and regulations in those countries. Those laws and regulations, as currently imposed, are not anticipated to have a material adverse effect upon our operations.

Risk Factors

The nature of our business activities and operations subjects us to a number of risks and uncertainties. If any of the events described below were to occur, they could have a material adverse effect on our business, financial condition and operating results.

Oil and gas prices fluctuate widely, and low oil and gas prices could adversely affect, and in the past have adversely affected, our financial results.

Our revenues, operating results, cash flows and future rate of growth depend substantially upon prevailing prices for oil and gas. Historically, oil and gas prices and markets have been volatile and are likely to continue to be volatile in the future. The average prices that we currently receive for our production are higher than historical averages. However, a future significant decrease in oil and gas prices, such as that experienced in 1998 and the first half of 1999, could have a material adverse effect on our cash flows and profitability. The substantial and extended decline in oil and gas prices during 1998 and 1999 adversely affected our financial condition and results of operations. A sustained period of low prices could have a material adverse effect on our earnings and financial condition.

Prices for oil and gas are subject to wide 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 that are beyond our control, including:

- political conditions in oil producing regions, including the Middle East;

domestic and foreign supplies of oil and gas;

levels of consumer demand;

weather conditions;

domestic and foreign government regulations;

prices and availability of alternative fuels; and

overall economic conditions.

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In addition, various factors may adversely affect our ability to market our oil and gas production, including:

- capacity and availability of oil and gas gathering systems and pipelines;
- effects of foreign, federal and state regulation of production and transportation;
- general economic conditions;
- changes in supply due to drilling by other producers;
- availability of drilling rigs; and
- changes in demand.

Lower oil and gas prices may adversely affect our level of capital expenditures, reserve estimates and borrowing capacity.

Lower oil and gas prices, such as those we experienced in 1998 and the first half of 1999, have various adverse effects on our business, including reducing cash flows which, among other things, have caused us in the past, and may cause us in the future, to decrease our capital expenditures. A smaller capital expenditure program may adversely affect our ability to increase or maintain our reserve and production levels. Lower prices may also result in reduced reserve estimates, write-offs of impaired assets and decreased earnings or losses due to lower reserves and higher depreciation, depletion and amortization expense. For example, in the fourth quarter of 1998 we recorded a significant non-cash charge for the impairment of oil and gas properties due to lower oil and gas prices.

The amount we can borrow under our revolving credit facility is subject to periodic redetermination based, in part, on expectations of future oil and gas prices applied to our oil and gas reserve estimates. Lower oil and gas prices could result in future reductions in the borrowing base under our revolving credit facility because lower oil and gas reserve values would reduce our liquidity and possibly trigger mandatory loan repayments. Furthermore, reduction in our liquidity could impede our ability to fund future acquisitions. Lower prices may also cause us to not be in compliance with maintenance covenants under our revolving credit facility and may negatively affect our credit statistics and coverage ratios.

Our significant level of indebtedness requires that a significant portion of our cash flows be used to pay interest and may limit our ability to fund capital expenditures or obtain additional financing to fund other obligations.

We currently have a significant amount of indebtedness. At December 31, 2003, our total long-term debt outstanding was approximately $699.9 million and we had a long-term debt to total capitalization ratio of 60 percent, considering cash on hand. Our significant indebtedness could have important consequences. For example:

our ability to obtain any necessary financing in the future for working capital, capital expenditures, acquisitions, debt service requirements or other purposes may be limited;

a portion of our cash flows from operations must be utilized for the payment of interest on our indebtedness and will not be available for financing capital expenditures or other purposes;

our level of indebtedness and the covenants governing our current indebtedness could limit our flexibility in planning for, or reacting to, changes in our business because certain financing options may be limited or prohibited;

we are more highly leveraged than some of our competitors, which may place us at a competitive disadvantage;

our level of indebtedness may make us more vulnerable during periods of low oil and gas prices or in the event of a downturn in our business because of our fixed debt service obligations; and

the terms of our revolving credit facility require interest and principal payments and maintenance of stated financial covenants. If the requirements of this facility are not satisfied, the lenders under this facility would be entitled to accelerate the payment of all outstanding indebtedness under this facility, and a default would be deemed to have occurred under the terms of our senior and senior subordinated notes. In such event, we cannot provide assurance that we would have sufficient funds available or could obtain the financing required to meet our obligations.

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We may be able to incur substantial additional indebtedness in the future. Our revolving credit facility would permit additional borrowings of up to approximately $157.6 million (considering outstanding letters of credit of approximately $0.9 million), as of February 27, 2004. For further discussion of our borrowing base, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity. If we were to add additional indebtedness to our current debt levels, the related risks discussed above, which we now face, could intensify.

Our future performance depends on our ability to find or acquire additional oil and gas reserves that are economically recoverable.

Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in oil and gas production and lower revenues and cash flows from operations. We have historically succeeded in substantially replacing reserves through acquisitions, exploration and development. We have conducted such activities on our existing oil and gas properties as well as on newly acquired properties. We may not be able to continue to replace reserves from such activities at acceptable costs. Lower oil and gas prices may further limit the types of reserves that can be developed at acceptable costs. Lower prices also decrease our cash flows and may cause us to reduce capital expenditures. The business of exploring for, developing or acquiring reserves is capital intensive. We may not be able to make the necessary capital investments to maintain or expand our oil and gas reserves if cash flows from operations are reduced and external sources of capital become limited or unavailable. In addition, exploration and development activities involve numerous risks that may result in dry holes, the failure to produce oil and gas in commercial quantities and the inability to fully produce discovered reserves.

We are continually identifying and evaluating acquisition opportunities, including acquisitions that would be significantly larger than those we have consummated to date. We cannot ensure that we will successfully consummate any acquisition, that we will be able to acquire producing oil and gas properties that contain economically recoverable reserves or that any acquisition will be profitably integrated into our operations.

Acquisitions carry unknown risks including the potential for environmental problems.

Our focus on acquiring producing oil and gas properties may increase our potential exposure to liabilities and costs for environmental and other problems existing on such properties. We expect to continue to focus, as we have done in the past, on acquiring producing oil and gas properties to replace reserves. Although we perform reviews of the acquired properties that we believe are consistent with industry practice, such reviews are inherently incomplete. In general, it is not feasible to perform an in-depth review of each individual property being acquired. Ordinarily, we focus our review efforts on the higher-valued properties and sample the remainder. However, even an in-depth review of all properties and records may not necessarily reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on each well included in an acquisition, and environmental problems, such as ground water contamination and surface and subsurface damages from leakage, spills, disposal or other releases of hazardous substances on such properties or from adjoining properties that have migrated to such properties, are not necessarily observable even when an inspection is performed.

Estimating reserves and future net revenues involves uncertainties and negative revisions to reserve estimates and oil and gas price declines may lead to impairment of oil and gas assets.

Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. The process relies on interpretations of available geological, geophysical, engineering and production data. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of developmental expenditures, including many factors beyond the control of the producer. The reserve data included in this Form 10-K represent estimates. In addition, the estimates of future net revenues from our proved reserves and the present value of such estimates are based on certain assumptions about future production levels, prices and costs that may not prove to be correct over time.

Quantities of proved reserves are estimated based on economic conditions in existence during the period of assessment. Lower oil and gas prices may have the impact of shortening the economic lives of certain fields because it becomes uneconomical to produce all recoverable reserves on such fields, which reduces proved property reserve estimates.

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If negative revisions in the estimated quantities of proved reserves were to occur, it would have the effect of increasing the rates of depreciation, depletion and amortization on the affected properties, which would decrease earnings or result in losses through higher depreciation, depletion and amortization expense. The revisions may also be sufficient to trigger impairment losses on certain properties which would result in a further non-cash charge to earnings. For example, we recorded a significant non-cash charge for the impairment of proved oil and gas properties in the fourth quarter of 1998 due to lower oil and gas prices and we recorded significant non-cash charges for the impairment of proved oil and gas properties in the fourth quarter of 2002 and in the second, third and fourth quarters of 2003 due to reserve revisions that resulted from additional geological, geophysical and engineering information and from revised production projections.

Our international operations may be adversely affected by political and economic instability, changes in the legal and regulatory environment and other factors.

International investments represent, and are expected to continue to represent, a significant portion of our total assets. We have international operations in Canada, Argentina, Bolivia, Yemen, Italy and Bulgaria. For 2003, our operations in Argentina accounted for approximately 37 percent of our revenues and 37 percent of our total assets. For 2003, our operations in Canada accounted for approximately 16 percent of our revenues and 15 percent of our total assets. During 2003, our operations in Argentina and Canada represented our only foreign operations accounting for more than 10 percent of our revenues or total assets. We continue to identify and evaluate international opportunities, but currently have no binding agreements or commitments to make any material international investment. As a result of such significant foreign operations, our financial results could be affected by factors such as changes in foreign currency exchange rates, weak economic conditions or changes in the political climate in these foreign countries.

Our foreign properties, operations or investments in Canada, Argentina, Bolivia, Yemen, Italy and Bulgaria may be adversely affected by political and economic instability, changes in the legal and regulatory environment and other factors. For example:

- local political and economic developments could restrict or increase the cost of our foreign operations;
- exchange controls and currency fluctuations could result in financial losses;
- royalty and tax increases and retroactive tax claims could increase costs of our foreign operations;
- expropriation of our property could result in loss of revenue, property and equipment;
- civil uprisings, riots, terrorist attacks and wars could make it impractical to continue operations, adversely affect both budgets and schedules and expose us to losses;
- import and export regulations and other foreign laws or policies could result in loss of revenues;
- repatriation levels for export revenues could restrict the availability of cash to fund operations outside a particular foreign country; and

laws and policies of the U.S. affecting foreign trade, taxation and investment could restrict our ability to fund foreign operations or may make foreign operations more costly.

Particularly, our Bolivian projects are dependent, in part, on the continued operation of the Bolivia-to-Brazil gas pipeline and the further development of gas markets in South America. The operation of this pipeline and the development of markets are subject to various factors outside of our control. In addition, in the event of a dispute arising from foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of the courts in the U.S. We may also be hindered or prevented from enforcing our rights with respect to actions taken by a foreign government or its agencies.

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The Argentine economic and political situation continues to evolve and the Argentine government may enact future regulations or policies that, when finalized and adopted, may materially impact, among other items:

- the realized prices we receive for oil and gas that we produce and sell;
- the timing of repatriations of cash to the U.S.;
- the amount of permitted export sales;
- the Argentine banking system;
- our asset valuations; and
- peso-denominated monetary assets and liabilities.

See Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Foreign Currency and Operations Risk included elsewhere in this Form 10-K.

Our hedging activities may expose us to the risk of financial loss in certain circumstances.

We have previously engaged in oil and gas hedging activities and intend to continue to consider various hedging arrangements to realize commodity prices which we consider favorable. The impact of changes in market prices for oil and gas on the average oil and gas prices we receive may be reduced based on the level of our hedging activities. These hedging arrangements may limit our potential gains if the market prices for oil and gas were to rise substantially over the price established by the hedge. In addition, our hedging arrangements expose us to the risk of financial loss in certain circumstances, including instances in which:

- production is less than expected;
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement; or
- the counterparties to our hedging arrangements fail to honor their financial commitments.

We currently have contracts hedging 6.7 MMBbls of oil for various periods in 2004 and 2005 at an average NYMEX reference price of $28.77 per Bbl.

Uninsured risks associated with our operations could result in a substantial financial loss.

Our operations are subject to all of the risks and hazards typically associated with the exploitation, development and exploration for, and the production and transportation of oil and gas. These operating risks include, but are not limited to:

- blowouts, cratering and explosions;
- uncontrollable flows of oil, natural gas or well fluids;
- fires;
- formations with abnormal pressures;
- pollution and other environmental risks; and
- natural disasters.

Any of these events could result in loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of such risks and losses. The occurrence of such an event not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

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Governmental and environmental regulations could adversely affect our business.

Our business is subject to certain foreign, federal, state and local laws and regulations on taxation, the exploration for and development, production and marketing of oil and gas, and environmental and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, prevention of waste and other matters. Such laws and regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning our oil and gas wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could decrease our revenues.

Our operations are subject to complex environmental laws and regulations adopted by the various jurisdictions where we operate. We could incur liabilities to governments or third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil or water, including responsibility for remedial costs. We could potentially discharge such materials into the environment in any of the following ways:

- from a well or drilling equipment at a drill site;
- leakage from gathering systems, pipelines, transportation facilities and storage tanks;
- damage to oil and natural gas wells resulting from accidents during normal operations; and
- blowouts, cratering and explosions.

Because the requirements imposed by such laws and regulations are frequently changed, we cannot ensure that laws and regulations enacted in the future, including changes to existing laws and regulations, will not adversely affect our business. In addition, because we acquire interests in properties that have been previously operated by others, we may be liable for environmental damage caused by such former operators.

Industry competition may impede our growth.

The oil and gas industry is highly competitive, and we may not be able to compete successfully or grow our business. We compete in the areas of property acquisitions and the development, production and marketing of, and exploration for, oil and gas with major oil companies, other independent oil and gas concerns and individual producers and operators. We also compete with major and independent oil and gas concerns in recruiting and retaining qualified employees. Many of these competitors have substantially greater financial and other resources than us. We may not be able to successfully expand our business or attract or retain qualified employees.

Employees

We employ approximately 240 full-time people in our Tulsa office whose functions are associated with management, engineering, geology, land, legal, accounting, financial planning and administration. In addition, approximately 160 full-time employees are responsible for the supervision and operation of our U.S. field activities. We also employ approximately 300 people for the management and operation of our properties in Canada, Argentina, Bolivia and Yemen. We believe our relations with our employees are excellent.

Item 3. Legal Proceedings.

We are a named defendant in lawsuits and are a party in governmental proceedings from time to time arising in the ordinary course of business. While the outcome of such lawsuits or proceedings against us cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position or results of operations.

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

There were no matters submitted to our stockholders during the fourth quarter of the fiscal year ended December 31, 2003.

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Item 4A. Executive Officers of the Registrant.

The following table sets forth as of the date hereof certain information regarding our executive officers. Officers are elected annually by the Board of Directors and serve at its discretion.

Name	Age	Position
Charles C. Stephenson, Jr.	67	Director, Chairman of the Board of Directors, President and Chief Executive Officer
William L. Abernathy	52	Director, Executive Vice President and Chief Operating Officer
William C. Barnes	49	Director, Executive Vice President, Chief Financial Officer, Secretary and Treasurer
William E. Dozier	51	Senior Vice President - Business Development
Larry W. Sheppard	49	Senior Vice President - New Ventures
Kellam Colquitt	56	Vice President - Exploration
Robert W. Cox	58	Vice President - General Counsel
Murphy B. Herrington	45	Vice President - Acquisitions
J. Chris Jacobsen	48	Vice President - U.S. Operations
Andy R. Lowe	52	Vice President - Marketing
Michael F. Meimerstorf	47	Vice President and Controller
Robert E. Phaneuf	57	Vice President - Corporate Development
Gary A. Watson	46	Vice President - Canadian Operations

Mr. Stephenson, our co-founder, has been a Director since June 1983 and Chairman of our Board of Directors since April 1987. He assumed the position of President and Chief Executive Officer on February 18, 2004. He was previously our Chief Executive Officer from April 1987 to March 1994 and our President from June 1983 to May 1990. From October 1974 to March 1983, he was President of Santa Fe-Andover Oil Company (formerly Andover Oil Company), an independent oil and gas company (Andover), and from January 1973 to October 1974, he was Vice President of Andover. Mr. Stephenson has a B.S. Degree in Petroleum Engineering from the University of Oklahoma and has approximately 44 years of oil and gas experience.

Mr. Abernathy has been a Director since October 1999, and an Executive Vice President and our Chief Operating Officer since December 1997. He was our Senior Vice President Acquisitions from March 1994 to December 1997, our Vice President Acquisitions from May 1990 to March 1994 and our Manager Acquisitions from June 1987 to May 1990. From June 1976 to June 1987, Mr. Abernathy was employed by Exxon Company USA, where he served at various times as Senior Staff Engineer, Senior Supervising Engineer and in other engineering capacities, with assignments in drilling, production and reservoir engineering in the Gulf Coast and offshore. He has B.S. and M.S. Degrees in Mechanical Engineering from Auburn University.

Mr. Barnes, a certified public accountant, has been a Director, and our Treasurer and Secretary since April 1987, an Executive Vice President since March 1994 and our Chief Financial Officer since May 1990. He was also a Senior Vice President from May 1990 to March 1994 and our Vice President Finance from January 1984 to May 1990. From November 1982 to December 1983, Mr. Barnes was an audit manager for Arthur Andersen & Co., an independent public accounting firm, where he dealt primarily with clients in the oil and gas industry. He was Assistant Controller Finance of Andover from December 1980 to November 1982. From June 1976 to December 1980, he was an auditor with Arthur Andersen & Co., where he dealt primarily with clients in the oil and gas industry. Mr. Barnes has a B.S. Degree in Business Administration from Oklahoma State University.

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Mr. Dozier has been our Senior Vice President Business Development since November 2002. He was our Senior Vice President Operations from December 1997 to November 2002 and from May 1992 to December 1997, he was our Vice President Operations. From June 1983 to April 1992, he was employed by Santa Fe Minerals, Inc., an independent oil and gas company (Santa Fe Minerals), where he held various engineering and management positions serving most recently as Manager of Operations Engineering. From January 1975 to May 1983, he was employed by Amoco Production Company serving in various positions where he worked all phases of production, reservoir evaluations, drilling and completions in the Mid-Continent and Gulf Coast areas. He has a B.S. Degree in Petroleum Engineering from the University of Texas.

Mr. Sheppard has been our Senior Vice President New Ventures since July 2003. He was our Vice President New Ventures from May 2001 to July 2003. From November 1994 to May 2001, he was our Vice President International. From June 1984 to August 1994, he was employed by Santa Fe Minerals serving as Manager Acquisitions & Special Projects, Manager International Operations, and in various other management and supervisory capacities. From August 1977 to June 1984, he was employed by Amoco Production Company serving in various engineering and supervisory capacities. He has a B.S. Degree in Petroleum Engineering from Texas Tech University.

Mr. Colquitt has been our Vice President Exploration since May 2001. From April 2000 to May 2001, he was our General Manager North American Exploration. He was employed by Ranger Oil Company, an independent oil and gas company, from August 1995 to January 2000 where he served as Vice President, International Exploration Western Hemisphere and Vice President, U.S. Operations. From December 1983 to July 1995 he was employed by Santa Fe Minerals serving as Manager International Exploitation, Exploration and Production, and in various other management and supervisory capacities. He was President of Colquitt Exploration, Inc. from 1978 to December 1983, providing contract exploration services. From 1971 to 1978, he served in various geology and supervisory capacities for Placid Oil Company. He has a B.S. Degree in Geology from Texas A&M University.

Mr. Cox has been our Vice President General Counsel since March 1988. From August 1982 to March 1988, he was employed by Santa Fe Minerals and its subsidiary, Andover, where he served at various times as Vice President Law and Regional Attorney. From April 1982 to August 1982, he was employed as Corporate Attorney by Andover. Prior to that time, Mr. Cox was employed by Amerada Hess Corporation, a major oil company, served as General Counsel and Secretary of Kissinger Petroleum Corporation, an independent oil and gas company, and served on the legal staff of Champlin Petroleum Company, an independent oil and gas company. He has a B.S. Degree in Business Administration with a major in Petroleum Marketing from the University of Tulsa, and a Juris Doctor from the University of Michigan Law School.

Mr. Herrington has been our Vice President Acquisitions since June 2003. He was our Acquisitions Technical Manager from May 1998 to June 2003 and an Acquisitions Engineer with us from March 1993 to May 1998. From December 1980 to March 1993, he was employed by Exxon Company USA, serving as a Reservoir Engineer. He has a B.S. Degree in Chemical Engineering from Mississippi State University.

Mr. Jacobsen has been our Vice President U.S. Operations since November 2002. Mr. Jacobsen was Senior Vice President of various exploitation and exploration staffs for KCS Energy, Inc. and Medallion Production Company, independent oil and gas companies, from 1994 to 2002. KCS Energy, Inc. declared bankruptcy under Chapter 11 of the U.S. Bankruptcy Code in January 2000. He was Senior Vice President at Netherland, Sewell & Associates, Inc., an independent petroleum engineering firm, where he managed engineering and geological teams from 1982 to 1994. From 1977 to 1982, he held various engineering and supervisory assignments with Exxon Company USA in Lafayette and New Orleans, Louisiana. He has a B.S. Degree in Chemical Engineering from Rose Hulman Institute of Technology.

Mr. Lowe has been our Vice President Marketing since December 1997. He was our General Manager Marketing from July 1992 to December 1997. He was President of Quasar Energy, Inc. from November 1990 to July 1992, providing downstream natural gas marketing services. From

September 1983 to November 1990, he was employed by Maxus Energy Corporation, formerly Diamond Shamrock Exploration Company, serving as Manager Marketing and in various other management and supervisory capacities. From 1981 to September 1983, he was employed by American Quasar Exploration Company as Manager Oil and Gas Marketing. From 1978 to 1981, he was employed by Texas Pacific Oil Company serving in various positions in production and marketing. He has a B.S. Degree in Education from Texas Tech University.

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Mr. Meimerstorf, a certified public accountant, has been our Controller since January 1988 and a Vice President since May 1990. He was our Accounting Manager from February 1984 to January 1988. From April 1981 to February 1984, he was the Financial Reporting Supervisor for Andover. From June 1979 to April 1981, he was an auditor with Arthur Andersen & Co. He has a B.S. Degree in Accounting from Arkansas Tech University and an M.B.A. Degree from the University of Arkansas.

Mr. Phaneuf has been our Vice President Corporate Development since October 1995. From June 1995 to October 1995, he was employed in the Corporate Finance Group of Arthur Andersen LLP, specializing in energy industry corporate finance activities. From April 1993 to August 1994, he was Senior Vice President and head of the Energy Research Group at Kemper Securities, an investment banking firm. From 1988 until April 1993, he was employed by Rauscher, Pierce Refsnes, Inc., an investment banking firm, as a Senior Vice President, serving as an energy analyst involved in equity research. From 1978 to 1988, Mr. Phaneuf was Vice President of Kidder, Peabody, & Co., an investment banking firm, serving as an energy analyst in the Research Department. From 1976 to 1978, he was employed by Schneider, Bernet, and Hickman, serving as an energy analyst in the Research Department. From 1972 to 1976, he held the position of Investment Advisor for First International Investment Management, a subsidiary of NationsBank. He holds a B.A. Degree in Psychology and an M.B.A. Degree from the University of Texas.

Mr. Watson has been our Vice President Canadian Operations since June 2001. He was our General Manager Latin American Operations from February 1998 to June 2001 and General Manager Vintage Oil Argentina, Inc. from August 1995 to February 1998. From March 1987 to July 1995, he was employed by Santa Fe Minerals where he held various engineering and management positions serving most recently as Manager of Project Development. From August 1985 to January 1987, he was employed by Williams Exploration Company as an engineer, with assignments in operations and reservoir engineering. From September 1984 to July 1985, he was Bank Representative in the Energy Group of Texas Commerce Bank. From May 1979 to August 1984, he was employed by Texaco, Inc. as an engineer in the New Orleans Division. He has a B.S. Degree in Chemical Engineering (Petroleum Option) from the University of Pittsburgh.

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PART II

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

Our common stock commenced trading on the New York Stock Exchange on August 3, 1990, under the symbol VPI. The following table sets forth the high and low sales prices per share of our common stock, as reported in the New York Stock Exchange composite transactions, and the cash dividends paid per share of our common stock for the periods indicated:

	High	Low	Dividends Paid
2003			
First Quarter	$ 11.46	$ 9.00	$ 0.040
Second Quarter	12.34	9.10	0.040
Third Quarter	12.10	10.51	0.045
Fourth Quarter	12.93	10.14	0.045
2002			
First Quarter	$ 14.70	$ 7.85	$ 0.035
Second Quarter	14.96	10.61	0.035
Third Quarter	11.80	8.10	0.040
Fourth Quarter	11.50	8.32	0.040

Substantially all of our stockholders maintain their shares in street name accounts and are not, individually, stockholders of record. As of December 31, 2003, our common stock was held by 210 holders of record and approximately 12,500 beneficial owners.

We began paying a quarterly cash dividend in the fourth quarter of 1992 and we continued paying a regular quarterly cash dividend through the first quarter of 1999. Due to the historically low oil and gas price environment during the first quarter of 1999, we suspended our regular quarterly cash dividend for the remainder of 1999. We re-instituted the payment of dividends beginning in the first quarter of 2000 with a $0.025 per share cash dividend and we expect to continue paying a regular quarterly cash dividend.

Our credit arrangements (including the indentures for our outstanding senior and senior subordinated indebtedness) contain certain restrictions on the distributions to common stockholders, including payment of cash dividends. However, none of these restrictions materially limit our ability to pay dividends at this time. Subject to these restrictions in our credit arrangements, the determination of the amount of future cash dividends, if any, to be declared or paid, will depend on, among other things, our financial condition, funds from operations, the level of our capital expenditures and our future business prospects.

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Item 6. Selected Financial Data.

SELECTED FINANCIAL AND OPERATING DATA

	Years Ended December 31,				
	2003	2002	2001	2000	1999
	(In thousands, except per share amounts and operating data)				
Statement of Operations Data:					
Oil and gas sales	$ 660,873	$ 577,699	$ 707,090	$ 649,736	$ 366,608
Gas marketing revenues	98,451	66,516	130,209	128,836	60,275
Oil and gas gathering and processing revenues	8,089	5,731	17,032	19,998	6,955
Total revenues and other income (expense)	756,327	664,263	884,967	775,380	492,561
Operating and administrative costs	387,994	325,998	396,912	334,118	217,540
Exploration costs	74,932	42,734	21,587	22,677	14,684
Depreciation, depletion and amortization	143,695	178,902	165,984	98,042	106,484
Impairment of proved oil and gas properties	370,244	98,720	29,050	225	3,306
Accretion	7,340				
Amortization of goodwill			11,940		
Impairment of goodwill	25,673	76,351			
Interest	69,917	77,714	64,720	48,437	58,634
Loss on early extinguishment of debt	6,909	8,154			
Income (loss) from continuing operations before cumulative effect of changes in accounting principles	(258,870)	(105,222)	126,449	171,486	67,661
Income from discontinued operations, net of income taxes	10,844	22,105	7,058	25,421	5,710
Income (loss) before cumulative effect of changes in accounting principles	(248,026)	(83,117)	133,507	196,907	73,371
Net income (loss)	(240,907)	(143,664)	133,507	195,893	73,371
Income (loss) per share from continuing operations before cumulative effect of changes in accounting principles:					
Basic	(4.04)	(1.66)	2.01	2.74	1.17
Diluted	(4.04)	(1.66)	1.98	2.68	1.14
Income (loss) per share before cumulative effect of changes in accounting principles:					
Basic	(3.87)	(1.31)	2.12	3.15	1.27
Diluted	(3.87)	(1.31)	2.09	3.08	1.24
Income (loss) per share:					
Basic	(3.76)	(2.27)	2.12	3.13	1.27
Diluted	(3.76)	(2.27)	2.09	3.06	1.24
Dividends declared per share	0.18	0.16	0.14	0.14	
Balance Sheet Data (end of year):					
Total assets	$ 1,446,838	$ 1,775,804	$ 2,107,902	$ 1,352,002	$ 1,168,454
Long-term debt	699,943	883,180	1,010,673	464,229	625,318
Stockholders equity	422,486	570,992	729,443	624,857	431,129

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	Years Ended December 31,				
	2003	2002	2001	2000	1999
	(In thousands, except per share amounts and operating data)				
Operating Data:					
Production:					
Oil (MBbls)	18,032	20,859	21,974	19,861	16,877
Gas (MMcf)	58,340	69,846	75,641	53,729	48,354
BOE	27,755	32,500	34,581	28,816	24,936
Average Sales Prices:					
Oil (per Bbl)	$ 25.88	$ 21.27	$ 21.93	$ 25.55	$ 16.92
Gas (per Mcf)	3.38	2.26	3.30	3.22	1.89
Proved Reserves (end of year):					
Oil (MBbls)	292,798	348,697	332,261	318,560	303,190
Gas (MMcf)	926,039	1,083,546	1,216,724	1,023,208	988,989
Total proved reserves (MBOE)	447,138	529,288	535,048	489,095	468,022
Present value of estimated future net revenues before income taxes discounted at 10 percent (in thousands)	$ 3,506,125	$ 4,009,322	$ 1,914,073	$ 4,338,616	$ 2,989,626
Standardized measure of discounted future net cash flows (in thousands)	2,382,528	2,746,257	1,438,141	2,951,121	2,247,237

Significant acquisitions of producing oil and gas properties during 2001 and 1999 and significant dispositions of oil and gas properties during 2003, 2002, 2001 and 1999 affect the comparability between the Financial and Operating Data for the years presented above. The statement of operations data reflect the presentation of our operations in Trinidad and Ecuador as discontinued operations for all periods (see Note 9 to our consolidated financial statements included elsewhere in this Form 10-K). The operating data include the results from discontinued operations for all periods.

The amounts in the Proved Reserves (end of year) section above include amounts related to the 10 year extension periods contained in our Argentina concession agreements. See Note 13 to our consolidated financial statements included elsewhere in this Form 10-K.

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

Overview

We are an independent energy company with operations primarily in the exploration and production, gas marketing and oil and gas gathering and processing segments of the oil and gas industry. We have operations or exploration activities in North America, South America, Yemen, Italy and Bulgaria. We are focused on the acquisition of oil and gas properties which contain the potential for increased value through exploitation and exploration. In addition, we are focused on continuing to build an inventory of exploration prospects in North America that may impact production in the near term as well as high potential frontier prospects that may impact production in the longer term.

For the last two years we have been focused on managing our financial leverage, maintaining liquidity and positioning ourselves for long-term growth. As a result of the acquisitions in Canada and Argentina in 2001, we ended 2001 with $1.0 billion of long-term debt. Since that time, we have improved our balance sheet and leverage position by reducing long-term debt by over $300 million. In addition, we have $55 million of cash at December 31, 2003. We funded this reduction in debt with proceeds from property sales, reducing our capital expenditures and cash provided by operating activities. In addition to cash on hand, as of February 27, 2004, we have unused availability under our revolving credit facility of $157.6 million (considering outstanding letters of credit of approximately $0.9 million).

Our cash provided by continuing operations for 2003 was $273.6 million, which was 21 percent greater than 2002, even though our production in 2003 declined 12 percent versus 2002 on a BOE basis, as significantly higher oil and gas prices more than offset the impact of this decline. The production decline is the result of the property sales and natural production declines, impacted by reduced capital expenditure programs in 2002.

Even though our cash provided by operating activities was strong, we reported a net loss of $240.9 million in 2003 versus a net loss of $143.7 million in 2002. The losses in both years were driven by non-cash charges for impairments of our Canadian oil and gas properties and goodwill as a result of negative revisions to our Canadian reserves. While we are disappointed with these results, our liquidity and financial position remain strong as these non-cash charges had no material adverse impact on our financial covenants under our debt instruments. We will be focused on returning to profitability in 2004.

We have 447.1 million BOE of oil and gas reserves as of December 31, 2003, reflecting the sale of 55.2 million BOE of reserves and production of 27.8 million BOE in 2003. Excluding the negative additions and revisions to our Canadian reserves, we added 27.2 million BOE to our reserves, at a cost of $6.69 per BOE, replacing 97 percent of our production. However, the substantial negative net additions and revisions in Canada totaled 26.3 million BOE negated all of the net additions and results generated from our operations in our other countries. During 2003, we made oil and gas capital expenditures of $181.8 million, spending 66 percent of our cash provided by continuing operations.

Our focus for 2004 is to return to profitability with production and reserve growth from a balance of acquisitions, exploitation and exploration. We have increased our non-acquisition oil and gas capital expenditure budget to $225 million, which is 24 percent greater than our spending in 2003. We expect to have sufficient internally generated cash flows to fund our non-acquisition capital expenditures plus provide additional cash for debt reduction. In the event we successfully secure acquisitions of oil and gas properties, we will seek appropriate levels of oil and gas price risk management and equity capital in order to maintain or improve our capital structure. We have already reduced our expected interest costs for 2004 by advancing funds under our revolving credit facility to repay our 9 3/4% senior subordinated notes due 2009.

Our future financial results depend on a number of factors, including in particular oil and gas prices, our ability to find or acquire oil and gas reserves, access to capital, our ability to control costs and both domestic and foreign regulatory developments. Commodity prices are impacted by many factors that are outside of our control. Historically, commodity prices have been volatile and we expect them to remain volatile. Oil and gas prices are affected by changes in market demands, overall economic activity, political events, weather, inventory storage levels, basis differentials and other factors. As a result, we can not accurately predict future oil and gas prices, and therefore, we can not determine what effect increases or decreases will have on our capital programs, production volumes, future revenues or our ability to acquire oil and gas properties. In addition to production volumes and commodity prices, acquiring, finding and developing sufficient amounts of oil and gas reserves at economical costs are critical to our long-term success.

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Results of Operations

Our results of operations have been significantly affected by our success in acquiring oil and gas properties and our ability to maintain or increase production through our exploitation and exploration activities. Significant acquisitions and dispositions of producing oil and gas properties during 2003, 2002 and 2001 affect the comparability of operating data for the periods presented in the tables below. Fluctuations in oil and gas prices have also significantly affected our results. The following tables reflect our oil and gas production and our average oil and gas prices for the periods presented:

	Years Ended December 31,		
	2003	**2002**	**2001**
Production:			
Oil (MBbls) -			
U.S.	6,199	6,796	8,409
Canada	1,248	1,829	1,539
Argentina [(a)]	10,388	10,942	10,548
Bolivia [(b)]	83	118	101
Continuing operations	17,918	19,685	20,597
Ecuador [(c)]	114	1,174	1,375
Trinidad			2
Total	18,032	20,859	21,974
Gas (MMcf) -			
U.S.	23,097	24,841	34,168
Canada	19,153	29,951	22,132
Argentina	9,838	8,630	10,253
Bolivia	6,252	6,424	9,088
Total	58,340	69,846	75,641
MBOE from continuing operations	27,641	31,326	33,204
Total MBOE	27,755	32,500	34,581

(a) Production for Argentina for the years ended December 31, 2003, 2002 and 2001, before the impact of changes in inventories was 10,273 MBbls, 10,771 MBbls, and 10,644 MBbls, respectively.

(b) Production for Bolivia for the years ended December 31, 2003, 2002 and 2001, before the impact of changes in inventories was 83 MBbls, 95 MBbls and 125 MBbls, respectively.

(c) Production for Ecuador for the years ended December 31, 2003, 2002 and 2001, before the impact of changes in inventories was 114 MBbls, 1,191 MBbls and 1,375 MBbls, respectively.

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	Years Ended December 31,		
	2003	2002	2001
Average Sales Price (including impact of hedges):			
Oil (per Bbl) -			
U.S.	$ 24.98	$ 21.78	$ 23.08
Canada	28.18	21.62	20.55
Argentina	26.14	20.98(a)	21.80
Bolivia	23.04	20.73	20.06
Continuing operations	25.87	21.31(a)	22.22
Ecuador	26.87	20.46	17.65
Total	25.88	21.27(a)	21.93
Gas (per Mcf) -			
U.S.	$ 4.20	$ 2.85	$ 4.83
Canada	4.35	2.48	2.50
Argentina	0.46	0.37	1.30
Bolivia			