VINTAGE PETROLEUM INC
Form 10-K
March 17, 2003
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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, 2002

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, $.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 28, 2002, the aggregate market value of the Registrant s Common Stock held by non-affiliates was approximately $606,800,000.

As of February 28, 2003, 63,936,275 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 13, 2003, 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, 2002

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PART I

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Certain Definitions

As used in this Form 10-K:

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

Mcf means thousand cubic feet, MMcf means million cubic feet, Bcf means billion cubic feet, Tcf means trillion cubic feet, MMBtu means million British thermal units, Bbl means barrel, MBbls means thousand barrels, 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.

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

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.

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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 the Company expects, believes or anticipates will or may occur in the future are forward-looking statements. The words believes, intends, expects, anticipates, projects, estimates, predicts an expressions 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; and**
- **expansion and growth of our business and operations.**

These statements are based on certain assumptions and analyses made by the Company in light of its experience and its perception of historical trends, current conditions and expected future developments as well as other factors it believes are appropriate in the circumstances. However, whether actual results and developments will conform with the Company s expectations and predictions is subject to a number of risks and uncertainties which could cause actual results to differ materially from the Company s expectations, including:

- **risk factors discussed in this Form 10-K and listed from time to time in the Company s filings with the Securities and Exchange Commission;**
- **oil and gas prices;**
- **exploitation and exploration successes;**
- **actions taken and to be taken by the Argentine government as a result of the country s economic instability;**
- **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 the Company;**
- **changes in laws or regulations; and**
- **other factors, most of which are beyond the control of the Company.**

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 the Company will be realized or, even if substantially realized, that they will have the expected consequences to or effects on the Company or its business or operations. The Company assumes 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

The Company s public internet site is http://www.vintagepetroleum.com. The Company makes available free of charge through its internet site, via a link to the EDGAR database of the Securities and Exchange Commission (SEC), its 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 the Company electronically files such material with, or furnishes it to, the SEC.

In addition, the Company makes available on http://www.vintagepetroleum.com its 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

The Company is 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. The Company is focused on the acquisition of oil and gas properties which contain the potential for increased value through exploitation and exploration. The Company, through its experienced management and technical staff, has 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 its exploration and development activities associated with acquisitions, the Company continues to build an inventory of exploration prospects in North America that may impact production in the near term as well as high impact frontier prospects that may impact production in the longer term.

At December 31, 2002, the Company owned and operated producing properties in nine states in the U.S., with its domestic proved reserves located primarily in four core areas: West Coast, Gulf Coast, East Texas and Mid-Continent. During 2001, the Company significantly expanded its North American operations in Canada through the acquisition of 100 percent of Genesis Exploration Ltd. (Genesis, now Vintage Petroleum Canada, Inc.). See Acquisitions. Additionally, the Company has international core areas located in Argentina and Bolivia. In Argentina, the Company owns 20 oil concessions, 16 of which are operated by the Company. Fourteen of these operated concessions are located in the south flank of the San Jorge Basin in southern Argentina. The Company expanded its 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, the Company owns and operates three blocks in the Chaco Plains area of southern Bolivia and the Naranjillos concession located in the Santa Cruz Province. The Company has exploration activities currently ongoing in Yemen and Italy. The Company also previously operated three blocks in the Oriente Basin in Ecuador. However, on January 31, 2003, the Company sold its operations in Ecuador. See Divestitures.

As of December 31, 2002, the Company owned interests in 3,567 gross (3,006 net) productive wells in the U.S., of which approximately 89 percent are operated by the Company, 720 gross (483 net) productive wells in Canada, of which approximately 61 percent are operated by the

Company, 1,589 gross (1,428 net) productive wells in Argentina, of which approximately 83 percent are operated by the Company, 15 gross (14 net) productive wells in Bolivia, all of which are operated by the Company, and 11 gross (8 net) productive wells in Ecuador, all of which were operated by the Company. As of December 31, 2002, the Company s properties had proved reserves of 529.3 MMBOE, comprised of 348.7 MMBbls of oil and 1.1 Tcf of gas, with a present value of estimated future net revenues before income taxes (utilizing a 10 percent discount rate) of $4.0 billion and a standardized measure of discounted future net cash flows of $2.7 billion. From the first quarter of 2000 through the fourth quarter of 2002, the Company increased its average net daily production from 52,900 Bbls of oil to 53,300 Bbls of oil and from 125,000 Mcf of gas to 182,200 Mcf of gas.

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

The Company was incorporated in Delaware on May 31, 1983. The Company s principal office is located at 110 West Seventh Street, Tulsa, Oklahoma 74119-1029, and its telephone number is (918) 592-0101.

Business Strategy

The Company s overall goal is to maximize its value through profitable growth in its oil and gas reserves and production. The Company has been successful at achieving this goal through its 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 a low cost structure and (d) maintaining financial flexibility. Key elements of the Company s strategy include:

Acquisitions of Producing Properties. The Company has an experienced management and technical team which focuses on acquisitions of operated producing properties that meet its 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. The Company s emphasis on property acquisitions reflects its 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 the Company to rapidly grow its reserves at favorable acquisition prices. From January 1, 2000, through December 31, 2002, the Company has spent $698.7 million acquiring 96.2 MMBOE of proved oil and gas reserves at an average acquisition cost of $7.26 per BOE. The Company replaced, through acquisitions, approximately 100 percent of its production of 95.9 MMBOE during the same period. For additional information, see Acquisitions. Although the Company made no acquisitions in 2002, management is continually identifying and evaluating acquisition opportunities, including acquisitions that would be significantly larger than many of those consummated to date by the Company. No assurance can be given that any such acquisitions will be successfully consummated.

Exploration and Development. The Company pursues workovers, recompletions, secondary recovery operations and other production optimization techniques on its properties, as well as development and infill drilling, with the goals of offsetting normal production declines and replacing the Company s annual production. The Company s overall exploration strategy balances high potential international prospects with lower risk drilling in known formations in North America and Argentina. The Company makes extensive use of geophysical studies, including 3-D seismic data, which reduces the cost of its exploration program by increasing its success rate. From January 1, 2000, through December 31, 2002, the Company spent approximately $526.5 million on exploration and development activities. As a result of all of these activities, including the impact of reserve revisions, during the three-year period ended December 31, 2002, the Company succeeded in adding 85.2 MMBOE to proved reserves, replacing approximately 89 percent of production during the same period at a cost of $6.18 per BOE. During 2002, the Company spent $129.7 million on exploration and development activities and added 40.0 MMBOE to proved reserves (including the impact of reserve revisions), replacing approximately 123 percent of 2002 production at a cost of $3.23 per BOE. For additional information, see Exploration and Development. The Company continues to maintain an extensive inventory of exploration and development opportunities. The total 2003 non-acquisition capital budget has been set at $185 million, a 43 percent increase over 2002 spending. The exploration portion of the 2003 capital budget of approximately $56 million will primarily focus on North America, with other projects planned for Yemen, Bolivia and Italy.

Low Cost Structure. The Company believes it is an efficient operator and capitalizes on its low cost structure in evaluating acquisition opportunities. The Company has generally achieved substantial reductions in labor and other field level costs from those experienced by the previous operators. In addition, the Company targets acquisition candidates which are located in its core areas and provide opportunities for cost efficiencies through consolidation with other Company operations. The lower cost structure has generally allowed the Company to substantially improve the cash flows of newly acquired properties.

Financial Flexibility. The Company is committed to maintaining financial flexibility, which management believes is important for the successful execution of its acquisition, exploitation and exploration strategy. Since 1990, the Company has completed five public equity offerings, two public debt offerings and three Rule 144A private debt offerings, all of which have provided the Company with aggregate net proceeds of approximately $1.2 billion. The Company announced in early 2002 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 the Company s operations in Trinidad and its heavy oil properties in California in 2002, along with the Company s operations in Ecuador in January 2003, resulted in the achievement of the Company s $200 million debt reduction goal. After giving pro forma effect to the estimated after-tax proceeds from the sale of its operations in Ecuador, the Company s net debt at December 31, 2002, would be approximately $775 million. This compares to net debt at December 31, 2001, of approximately $1.0 billion. The Company is considering additional debt reduction in 2003 to continue its progress toward lower debt levels. Currently, the Company anticipates that any such de-leveraging would be funded by additional sales of non-strategic assets. Cash on hand, internally generated cash flows, the borrowing capacity under its revolving credit facility and its ability to adjust its level of capital expenditures are the Company s major sources of liquidity. In addition, the Company may use other sources of capital, including the issuance of additional debt securities or equity securities, to fund any major acquisitions it might secure in the future and to maintain its 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, the Company has allocated a substantial portion of its capital expenditures to the acquisition of producing oil and gas properties. The Company s continuing emphasis on reserve additions through property acquisitions reflects its belief that consolidation and restructuring activities on the part of major integrated, large independent and national oil companies has afforded in recent years, and should afford in the future, favorable opportunities to purchase domestic and international producing properties.

Since the Company s incorporation in May 1983, it has 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, a series of acquisitions made by the Company established a new core area in the San Jorge Basin in southern Argentina. In late 1996, the Company expanded its South American operations into Bolivia and, in 1998, into Ecuador. In 1999, the Company entered into a farm-in agreement for the S-1 Damis exploration block in Yemen and in December 2000, made its initial entrance into Canada and Trinidad with the purchase of 100 percent of Cometra Energy (Canada), Ltd. (Cometra), a privately-held Canadian company. The Company significantly expanded its Canadian operations in 2001 with the purchase of 100 percent of Genesis, a publicly-traded Canadian company. The Company also extended its Argentine operations in 2000 with its acquisition of two concessions from Perez Companc and in 2001 with its 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 the Company made no acquisitions in 2002, management is constantly identifying and evaluating additional acquisition opportunities which may lead to expansion into new domestic core areas or other countries which the Company believes are politically and economically stable.

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From January 1, 2000, through December 31, 2002, the Company made oil and gas reserve acquisitions with costs totaling approximately $698.7 million. As a result of these acquisitions, the Company acquired approximately 96.2 MMBOE of proved oil and gas reserves. The following table summarizes the Company s acquisition experience during the periods indicated:

	Acquisition Costs (In thousands)	Proved Reserves When Acquired Oil (MBbls)	Gas (MMcf)	MBOE	Cost Per BOE When Acquired
North America Acquisitions:					
2000	$ 53,962	2,854	41,166	9,715	$ 5.55
2001	564,950	27,493	207,701	62,110	9.10
2002					
Total North America Acquisitions	618,912	30,347	248,867	71,825	8.62
South America Acquisitions:					
2000	37,486	11,970	2,278	12,350	3.04
2001	42,267	11,724	1,636	11,997	3.52
2002					
Total South America Acquisitions	79,753	23,694	3,914	24,347	3.28
Total Acquisitions	$ 698,665	54,041	252,781	96,172	$ 7.26

Divestitures

During 2002, the Company continued its divestiture program designed to sell properties that were either marginally economical or non-strategic to the Company s areas of operation. The Company determined that the level of investment and time horizon required to continue the development of its interests in Ecuador and Trinidad were inconsistent with the timing of its desire to reduce leverage. These assets, along with the Company s remaining heavy oil properties in the Santa Maria area of southern California, were identified for sale. The Company s heavy oil properties in the Santa Maria area of southern California 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. The Company received a cash payment as final settlement of this note in October 2002. The Company s interest in Trinidad was sold in July 2002 for $40 million in cash. In total, property sales in 2002 resulted in $48.4 million in gains ($25.1 million after tax), which were included in the Company s 2002 operating results. Combined, the Company estimates that the properties sold in 2002 accounted for proved reserves of 2.4 MMBbls of oil and 65.0 Bcf of gas as of the closing dates of the sales, which represents three percent of the Company s total proved reserves at December 31, 2002.

On December 16, 2002, the Company announced that it had signed an agreement to sell its operations in Ecuador. The transaction was approved by the Company s Board of Directors in December 2002 and the sale closed on January 31, 2003. The Company received $137.4 million in cash, subject to post-closing adjustments. As of December 31, 2002, the Company s operations in Ecuador had proved reserves of 45.4 MMBbls of oil, which represents nine percent of the Company s total proved reserves at December 31, 2002.

The Company is also considering additional sales of other non-strategic assets in 2003. The Company has signed an agreement to sell certain U.S. Mid-Continent gas properties for $30 million, subject to post-closing adjustments, with closing anticipated by the end of the first quarter of 2003. With over one and one-half years of operating experience with the Genesis and Cometra properties, the Company has identified the Canadian assets most strategic to the future growth of its Canadian operation. As such, a 2003 divestiture program has been initiated to dispose of non-strategic Canadian assets and to provide for a more focused effort on future development and growth in Canada.

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Exploration and Development

The Company concentrates its acquisition efforts on proved producing properties which 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. The Company has pursued an active workover, recompletion and development drilling program on the properties it has acquired and intends to continue these activities in the future. The Company s exploitation staff focuses on maximizing the value of the properties within its reserve base, striving to offset normal production declines and to replace the Company s annual production.

The Company s exploration program is designed to contribute significantly to its growth. Management divides the strategic objectives of its exploration program into two parts. First, in North America and Argentina, the Company s exploration focus is in its core areas where its geological and engineering expertise and experience are greatest. State-of-the-art technology, including 3-D seismic data, is employed to identify prospects. Exploration in North America is designed to generate reserve growth in this core area in combination with its exploitation activities. The Company is increasing the magnitude of this program 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. The Company s international exploration projects currently underway in Yemen and Italy are characterized by higher potential and higher risk.

As a result of a reduced capital spending program, which was curtailed in order to provide funds for debt reduction, the Company spent $24.7 million on workovers, recompletion operations and other projects during 2002, significantly lower than 2001 s $62.0 million. A measure of the overall success of the Company s recompletion and workover operations during 2002 (excluding minor equipment repair and replacement) was that improved production or operating efficiencies were achieved from approximately 81 percent of such operations consistent with the average for the last three years of 80 percent.

Development drilling activity is generated both through the Company s 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 Company leases currently producing oil and gas. The Company intends to continue to pursue development drilling opportunities which offer potentially significant returns to the Company.

During 2002, the Company participated in the drilling of 74 gross (59 net) development wells, of which 64 gross (50 net) were productive. At December 31, 2002, the Company s proved reserves included approximately 154 development or infill drilling locations on its U.S. acreage, 82 locations on its Canada acreage, 417 locations on its Argentine acreage, 40 locations on its acreage in Ecuador, and 16 locations on its Bolivian acreage. In addition, the Company has an extensive inventory of development and infill drilling locations on its existing properties which are not included in proved reserves. Consistent with the reduced capital spending programs in 2002, the Company decreased its development and infill drilling capital expenditures for 2002, spending an aggregate of $50.5 million, compared to $96.2 million in 2001. Included in the 2002 development drilling was approximately $1.7 million in the U.S., $27.2 million in Canada, $10.4 million in Argentina and $11.2 million in Ecuador. The Company also spent approximately $4.1 million on the acquisition of development seismic data and other development activities in 2002.

The Company spent approximately $45.4 million on exploration activities in 2002, participating in the drilling of 40 gross (34 net) exploratory wells, of which 19 gross (15 net) were productive. Exploration spending for 2002 included $37.6 million in North America and $7.6 million in Yemen. The Company also spent approximately $5.0 million on the acquisition of unproved acreage in 2002, primarily in North America.

The Company s total 2003 non-acquisition capital budget has been set at $185 million, a 43 percent increase over 2002 spending. Planned development expenditures for 2003 are $129 million, including $79 million in North America and $48 million in Argentina. The exploration portion of the 2003 capital budget of approximately $56 million includes $39 million in North America, $6 million in Bolivia and $5 million in Yemen.

Exploration and development activities for 2002 were concentrated mainly in the U.S., Canada and Argentina core areas of the Company. The following is a brief description of significant developments in the Company s recent exploration and development activities:

United States. Consistent with the reduced capital spending programs in 2002, the Company decreased its United States capital expenditures for 2002, spending an aggregate of $29.5 million, compared to $61.8 million in 2001. The Company s U.S. development program for 2002 included the drilling of two gross (one net) development wells, of which 100 percent were successful. These two wells were drilled in the fourth quarter of 2002, one in California and one in Oklahoma, and had a combined initial gross daily production rate of 23 Bbls (21 Bbls net) of oil and 1.4 MMcf (0.4 MMcf net) of gas. The Company s 2002 U.S. development program also included 60 gross (48 net) workovers and recompletions (excluding minor equipment repair and replacement), of which 44 gross (37 net) resulted in improved production or operating efficiencies, for a 73 percent success rate. These workovers resulted in a combined initial gross daily production rate of 1,272 Bbls (511 Bbls net) of oil and 21.3 MMcf (4.9 MMcf net) of gas. The Company s gas reservoir de-watering project in the West Ranch field in south central Texas increased gross daily production from 21 producing wells to 5.0 MMcf (4.4 MMcf net) of gas and 250 Bbls (219 Bbls net) of oil. Response from this project is continuing to improve as reservoir pressure is drawn down, liberating previously unrecoverable trapped gas.

The Company s 2003 development budget has been significantly increased to include $49 million targeted towards U.S. projects. These projects will focus primarily on 35 development wells or sidetracks and 145 workovers and production enhancement projects. The Company initiated drilling on two horizontal infill development programs in the Luling and West Ranch fields in south central Texas during December 2002.

During 2003, the Company anticipates spending $31 million on its exploration activities in the U.S. Targeted activities for 2003 include plans to drill several prospects in its current inventory and to continue to build the inventory of prospects for future drilling opportunities. The Company is participating in the drilling of the Norman No. 1, an exploration well on the Richaud prospect developed from a 3-D seismic survey in Terrebonne Parish in south Louisiana. The well is currently drilling below 16,000 feet toward a targeted total depth of 20,000 feet. Results are expected during the second quarter of 2003. This gas prospect targets multiple lower Miocene Operc sands that are analogous to the producing sands in the prolific Lilly Boom field which is three miles to the southwest of and on trend with the Richaud prospect. The Company holds a 38 percent working interest in this prospect that has significant estimated gross unrisked reserve potential.

Using an established play concept in the Permian Basin of west Texas, the Company has generated three, multi-well, lower-risk gas prospects and will use horizontal drilling and fracture stimulation technology to produce gas from tight carbonate rocks in areas of known production. The Company has an interest in over 19,500 gross acres encompassing these three exploration prospects. The first well has begun drilling on the first of these prospects, the Leatherwood prospect, in Terrell County, Texas. Leatherwood is targeting Devonian Age tight carbonates at approximately 15,800 feet with significant estimated gross unrisked reserve potential. The Company has a 33 percent working interest in this well and results are expected during the second quarter of 2003. Two additional prospects are scheduled for drilling during the second and third quarters of 2003 and the Company s exploration team continues to generate additional tight carbonate prospects.

The Company is also pursuing Oligocene and Miocene Age exploration prospects offshore Texas, acquiring over 500 square miles of 3-D seismic data which is being used to generate multiple prospects. Lease acquisition should occur during the first half of 2003 and drilling is anticipated to begin by late 2003.

Canada. In 2002, the Company continued exploitation and exploration activity identified as part of the Genesis and Cometra acquisitions. The Company drilled 85 gross (69 net) development and extensional wells in 2002, of which 56 gross (42 net), or 66 percent, were successful. Drilling in 2002 continued to focus on the Sturgeon Lake, Grouard and West Central operating areas where the Company s most successful Canadian programs have been realized.

Wells in the Sturgeon Lake area target attic oil accumulations in Devonian reef structures identified and exploited by the application of 3-D seismic data and horizontal drilling. Successful wells may be significant, as demonstrated by North Sturgeon Lake 10-16 which began producing at an initial net daily rate of 278 Bbls of oil in July and was producing at a net daily rate of 209 Bbls of oil as of December 31, 2002. In total, Sturgeon Lake Leduc drilling provided an aggregate initial net daily production of 1,225 Bbls of oil from eight gross (eight net) wells (75 percent of which were successful) drilled during 2002. Detailed evaluation of this massive reef structure continues to provide additional drilling opportunities for undrained oil accumulations. Two prospects are currently scheduled for drilling in the first half of 2003, with additional locations budgeted for later in the year.

Ten gross (nine net) wells were drilled in the Grouard operating area during 2002, targeting the oil-productive Devonian Gilwood formation. At an average success rate of 50 percent, this program contributed an aggregate initial net daily production of 408 Bbls of oil to the Company in 2002. Reserve potential is delineated in Gilwood structural traps by the application of 3-D seismic data and surface geochemistry. With 16 square miles of additional 3-D seismic data recently acquired and processed, additional Gilwood locations are being identified for drilling in 2003.

In the West Central operating area, the Company is participating in an aggressive development program in the outside operated Oldman Field. This development targets gas accumulations in the Cretaceous Cardium formation. In 2002, the Company participated in the drilling of seven gross (three net) wells in this field at an overall success rate of 100 percent. Aggregate initial net daily production from this program was 3.6 MMcf of gas. Additional drilling is scheduled for 2003.

Consistent with the strategy that led to the entry into Canada, the Company is intensifying its efforts in generating additional impact exploration prospects within the country. Current exploration efforts include prospecting in three provinces and the Northwest Territories. Although several exploration prospects target oil accumulations, the majority of these high-potential prospects will target gas. This gas weighting is consistent with the Company s overall business plan to focus its North American exploration endeavor on gas prospects with significant reserve potential.

The Company has set its 2003 Canadian exploration and development budget at $38 million. During 2003, the Company anticipates drilling 52 gross (36 net) development and extensional wells in Canada. Activity will be concentrated in the Sturgeon Lake, Grouard and West Central operating areas. The first exploration efforts in 2003 focused upon the completion and testing of the three previously drilled exploratory wells in the Northwest Territories. As follow-up to surface geochemistry acquired during 2002, an additional exploration well in the Northwest Territories was drilled in the first quarter of 2003. These exploration efforts were unsuccessful at discovering commercial quantities of hydrocarbons. The Company will utilize the data obtained from these wells to continue the assessment of the exploration potential of the Northwest Territories assets. The Company may also obtain additional seismic and/or geochemical data to aid in the evaluation of future exploration prospects.

Argentina. Development and extensional drilling, workovers, and implementation of secondary recovery projects have been the focus of the Company s historical efforts on its Argentine properties. The Company continued its highly successful development drilling program in Argentina with the drilling of 20 gross (18 net) wells in 2002 with a 100 percent success rate. The Company s number of development drilling locations in Argentina has increased substantially in recent years, to 417 drilling locations recorded in its year-end 2002 proved reserves, due to a combination of acquisitions, development drilling and workover results, and additional locations identified from new seismic surveys acquired on the Company s acreage.

The Company s Argentine drilling program was suspended in early May 2002 due to economic and political uncertainty in Argentina, but was reinitiated in November 2002 once signs of stability had appeared in the economy. Due to the uncertainties, the Company instead focused a significant part of its 2002 capital effort on workovers and recompletions, which require less capital, are less risky, and provide short pay outs. The Company completed 107 gross (100 net) workovers and recompletions (excluding minor equipment repair and replacement), of which 95 gross (88 net), or 89 percent, resulted in improved production or operating efficiencies.

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The Company s drilling program in Argentina relies heavily on interpretation of 3-D seismic data to aid in the optimum placement of wells. A total of 178 square miles of new 3-D seismic data was recorded in the Las Heras, Piedra Clavada and Meseta Espinosa concessions in December 2002. Interpretation of this data is underway to identify additional drilling prospects. With this new seismic data, the Company now has 682 square miles of 3-D seismic data which covers 37 percent of the area of all of its operated concessions. The Company believes that significant additional drilling potential will continue to be identified through the acquisition of future 3-D seismic surveys.

Planned 2003 investment activity in Argentina includes an increased level of drilling and workovers relative to 2002 predicated on the anticipated continued political and economic stability which has been achieved in recent months in Argentina (see Item 7A. Quantitative and Qualitative Disclosures About Market Risk Foreign Currency and Operations Risk included elsewhere in this Form 10-K). The total non-acquisition capital budget for Argentina in 2003 is currently $48 million. Included in the 2003 budgeted activity is a two rig drilling program during the first half of the year with the addition of a third drilling rig late in the second quarter of 2003. The drilling program targets drilling 62 wells in the San Jorge Basin and two wells in the Cuyo Basin.

Bolivia. The focus for the Company s operations in Bolivia continues to be on maximizing gas sales to existing markets and the development of new gas markets. During the fourth quarter of 2002, dew point control facilities were installed on the Naranjillos concession which ensured that gas production would meet pipeline specifications.

A geochemical survey was conducted during the third quarter of 2002. This survey covered approximately 100 square miles in the Chaco Block, located north of the Chaco Sur exploitation block. Information obtained from the survey, along with existing 2-D seismic data, will be used to further evaluate the exploration potential on the block. The Company currently plans to drill one well on the Chaco concession during 2003 at an estimated cost of $6.3 million to fulfill its outstanding work commitment in this block.

Ecuador. During 2002, the Company began the drilling program of four development and extensional drilling locations selected from the seismic survey completed in 2001 covering portions of Blocks 14, 17 and the Shiripuno Block. Two horizontal wells, the Hormiguero No. 4 and Hormiguero No. 3, were completed in Block 17 and one vertical well, the Wanke No. 2, was completed in Block 14 in the last half of 2002. A second vertical well in Block 14, the Nantu No. 3, was being completed in January 2003.

Production tests indicate that both the Hormiguero No. 3 and the Hormiguero No. 4 each have capacity in excess of 10,000 Bbls of oil per day. Both Hormiguero wells would require higher-volume lift equipment to sustain these rates. The Wanke No. 2 made a new discovery in the Napo U sand, which was a secondary target for the well. The producing interval in the Napo U sand production tested for 590 Bbls of oil per day. The M1-Tena, which was the primary target, will be tested at a later date. Production from all of the new wells is expected to be restricted until the new OCP pipeline is in operation in the second half of 2003.

On January 31, 2003, the Company sold its operations in Ecuador. See Divestitures.

Yemen. During 2002, the Company initiated its second exploratory campaign in the Republic of Yemen, where it has a 75 percent working interest in the S-1 Damis Block. The Company drilled three wells based on 3-D seismic data and geochemical surveys. The first well in the program, the Osaylan No. 1, encountered hydrocarbons in both the targeted Alif and Lam formations, however, preliminary results were disappointing with respect to the apparent potential extent of hydrocarbon accumulation. The well has been temporarily abandoned pending detailed evaluations of core analysis and petrophysical interpretation. A completion attempt could be made at a later date if warranted by the analyses underway.

The second exploration well of the 2002 drilling campaign, the An Nagyah No. 2, successfully tested oil from the sub-salt Lam formation. The well was drilled to a total depth of 5,327 feet and, based on electric log and other well information, the 65-foot interval from 3,310 to 3,375 feet in the upper Lam sand was selected for testing. The lower section of this interval from 3,345 to 3,375 feet flowed at a sustained, water-free rate of 860 barrels per day of oil and 400 Mcf per day of natural gas. After adding perforations from 3,326 to 3,345 feet, the well flowed on a short term test at a water-free rate of 1,091 barrels per day of oil and 543 Mcf per day of natural gas. Subsequently, the entire 65-foot interval was tested at a sustained, water-free rate of 410 barrels per day of oil and 3,700 Mcf per day of natural gas, indicating the likely presence of gas pay within the upper 16 feet of the pay interval. In 2003, drilling commenced on the An Nagyah No. 3 well to assist in assessing the potential of the oil discovery in the Lam formation made by the An Nagyah No. 2. Pending the results of the An Nagyah No. 3 well, the Company may drill one or more additional wells in 2003.

The final well in the 2002 drilling program, the An Naeem No. 3, was drilled to a depth of 5,325 feet and testing was completed in early 2003. The An Naeem No. 3 targeted an oil rim down dip to a gas discovery defined by the An Naeem No.1 and An Naeem No. 2 wells previously drilled by the Company. Although the third well successfully tested hydrocarbons in the targeted Alif formation, an oil rim was not encountered. The well tested natural gas at a rate of 3.8 million cubic feet per day and 12 barrels of condensate per day from a 26-foot, perforated interval. Operations have been suspended pending further evaluation of the An Naeem structure.

Italy. The Company has a 70 percent working interest in two exploration blocks in the Po valley, an industrial region of northern Italy which has a well-developed production history and pipeline infrastructure serving a highly developed gas market. The Company is the operator of the Bastiglia and Cento blocks covering approximately 275,000 gross acres. The Company s initial drilling campaign will target gas in combination structural and stratigraphic traps based on re-processed 2-D seismic data and newly acquired geochemical studies. The process of obtaining well permits is underway. The Company intends to spud two exploration wells during the fourth quarter of 2003 and drill to a target depth of 4,800 feet.

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Oil and Gas Properties

At December 31, 2002, the Company owned and operated domestic producing properties in nine states, with its U.S. proved reserves located primarily in four core areas: West Coast, Gulf Coast, East Texas and Mid-Continent. In addition, the Company established core areas in Argentina during 1995, Bolivia during 1996, Ecuador in 1998 and Canada in 2000. As of December 31, 2002, the Company operated 4,967 gross (4,688 net) productive wells and also owned non-operating interests in 935 gross (250 net) productive wells. The Company continuously evaluates the profitability of its oil, gas and related activities and has a policy of divesting itself of unprofitable leases or areas of operations that are not consistent with its operating philosophy. See Divestitures.

The following table sets forth estimates of the proved oil and gas reserves of the Company at December 31, 2002, as estimated by the independent petroleum consultants of Netherland, Sewell & Associates, Inc. for the U.S., Argentina and Ecuador, 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	47,642	5,395	53,037	94,061	3,955	98,016	69,373
Gulf Coast	20,423	6,964	27,387	57,241	34,031	91,272	42,599
East Texas	6,860	661	7,521	61,039	14,331	75,370	20,083
Mid-Continent	622	738	1,360	33,513	20,136	53,649	10,301
Total U.S.	75,547	13,758	89,305	245,854	72,453	318,307	142,356
Canada	10,620	7,869	18,490	161,200	21,825	183,025	48,994
Total North America	86,167	21,627	107,795	407,054	94,278	501,332	191,350
Argentina	106,135	83,259	189,394	43,737	84,427	128,164	210,755
Bolivia	4,721	1,343	6,064	353,259	100,791	454,050	81,739
Ecuador	8,302	37,143	45,444				45,444
Total Company	205,325	143,372	348,697	804,050	279,496	1,083,546	529,288

Estimates of the Company s 2002 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.

The Company s non-producing proved reserves are largely concentrated behind-pipe in fields which it operates. Undeveloped proved reserves are predominantly concentrated in development drilling locations and secondary recovery projects, most of which are operated by the Company.

On January 31, 2003, the Company sold its operations in Ecuador. See Divestitures.

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The following is a brief discussion of the Company s oil and gas operations in its 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, Grubb and Sisquoc formations are the dominant producing reservoirs on the Company s acreage in California with well depths ranging from 800 feet to 14,300 feet. As of December 31, 2002, the area comprised 13 percent of the Company s total proved reserves and 49 percent of the Company s U.S. proved reserves. The Company currently operates 1,313 gross (1,278 net) productive wells in this area and owns an interest in 150 gross (eight net) productive wells operated by others. During 2002, net daily production for this area averaged approximately 15,800 BOE, or 53 percent of total net daily U.S. production. Numerous workovers and recompletion opportunities exist in the San Miguelito, Buena Vista 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 steamflood expansion.

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, 2002, the Gulf Coast area comprised approximately eight percent of the Company s total proved reserves and 30 percent of its U.S. proved reserves. The Company currently operates 1,121 gross (1,089 net) productive wells in this area and owns an additional interest in 58 gross (16 net) productive wells operated by others. During 2002, net daily production from this area averaged approximately 11,100 BOE, or 37 percent of total net daily U.S. production. A significant inventory of workovers and recompletions exist 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, Travis Peak and Wilcox formations are the dominant producing reservoirs on the Company s 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 the Company s December 31, 2002, total proved reserves and 14 percent of its U.S. proved reserves. The Company currently operates 570 gross (493 net) productive wells in this area and owns an interest in an additional 79 gross (eight net) productive wells operated by others. During 2002, net daily production for this area averaged approximately 1,200 BOE, or four percent of total net daily U.S. production. Significant infill drilling potential exists on the Company s acreage in the South Gilmer, Edgewood, Southern Pine and Bear Grass 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 the Company s acreage in this area with well depths ranging from 1,560 feet to 17,260 feet. This area comprised two percent of the Company s December 31, 2002, total proved reserves and seven percent of its U.S. proved reserves. The Company currently operates 175 gross (100 net) productive wells in this area and owns an interest in an additional 101 gross (14 net) productive wells operated by others. During 2002, net daily production for this area averaged approximately 1,800 BOE, or six percent of total net daily U.S. production. Projects to improve the ultimate reserve recovery exist in the Shawnee Townsite waterflood and production response is anticipated from the Missouri Flats waterflood in 2003. The Company has signed an agreement to sell certain Mid-Continent properties. See Divestitures.

Canada. The Company s Canadian producing properties are located in the provinces of Alberta, Saskatchewan and British Columbia. The Company also has approximately 1.2 million net undeveloped acres located in Canada with a significant portion, aggregating to 435,000 net acres, in the Northwest Territories. The Canadian properties comprised approximately nine percent of the Company s December 31, 2002, total proved reserves. The Company currently operates 436 gross (380 net) productive wells in Canada and owns interests in 284 gross (103 net) wells operated by others. During 2002, net daily production averaged approximately 5,010 Bbls of oil and 82,060 Mcf of gas.

Argentina. The Argentine properties consist primarily of 14 mature producing concessions located on the south flank of the San Jorge Basin, all of which are operated by the Company, four concessions located in the Cuyo Basin in western Argentina, two of which are operated by the Company, and two non-operated concessions in the Neuquen Basin. These concessions comprised approximately 40 percent of the Company s December 31, 2002, total proved reserves. During 2002, net daily production averaged approximately 30,000 Bbls of oil and 23,640 Mcf of gas. The Company currently operates 1,326 gross (1,326 net) productive wells. In addition, the Company owns an interest in 263 gross (102 net) productive wells operated by others. At December 31, 2002, the Company s proved reserves included approximately 417 development drilling locations on its Argentine acreage. In addition, the Company has an extensive inventory of workovers and development or infill drilling locations on its Argentine properties which are not included in proved reserves.

Bolivia. The Bolivian properties consist of four producing concessions and one exploration concession located in the Chaco Basin of Bolivia. The Company has 100 percent working interests in the Chaco exploration concession and the Naranjillos, Chaco Sur and Porvenir producing concessions. In the other producing concession, Nupuco, the Company has a 50 percent working interest. The Company operates all four producing concessions. These concessions comprise approximately 15 percent of the Company s December 31, 2002, total proved reserves and include 15 gross (14 net) productive wells. Net daily production during 2002 averaged approximately 17.6 MMcf of gas and 325 Bbls of condensate. Current net daily productive capacity of the Company s properties in Bolivia is approximately 46 MMcf of gas and 690 Bbls of condensate. The Company is working to develop additional gas markets, both inside and outside of Bolivia, to increase the level of production from its concessions, which are currently market constrained.

Ecuador. The Company s properties in Ecuador consisted of two producing concessions and one exploration concession. The Company had a 70 percent working interest in the producing Block 17 concession and a 75 percent working interest in the producing Block 14 concession. The Company also had a 100 percent working interest in the Shiripuno exploration concession. At December 31, 2002, the Company operated 11 gross (eight net) productive wells with 2002 average net daily production of approximately 3,220 Bbls of oil. These concessions comprised nine percent of the Company s December 31, 2002, total proved reserves. On January 31, 2003, the Company sold its operations in Ecuador. See Divestitures.

Marketing

Generally, the Company s 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. The Company s Canadian oil production is sold under short-term contracts at posted prices. The Company s 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 Shell C.A.P.S.A. 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. In Ecuador, the Company s Block 14 and Block 17 oil production was sold to various third party purchasers at West Texas Intermediate spot prices less a specified differential. During 2002, approximately 24 percent and 10 percent of the Company s total operating revenues related to oil sales to ENAP and Esso S.A.P.A., respectively.

In January 2002, the Argentine government devalued the Argentine peso (peso) and enacted an emergency law that 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. 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.

The Company currently exports approximately 70 percent of its Argentine oil production. The Company believes that this export tax will have the effect of decreasing all future Argentine oil revenues (not only export revenues) by 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 to 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. The export tax is not deducted in the calculation of royalty payments.

On January 2, 2003, at the Argentine government s request, crude oil producers and refiners agreed to cap amounts payable for 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 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 ten consecutive days, which occurred on February 24, 2003.

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.

The Company s 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 the Company s North American gas is committed to long-term fixed-price contracts, the Company is positioned to take advantage of future strong gas price environments, but it is also subject to any future gas price declines. Most of the Company s 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. The Company s 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 may improve over time as domestic Argentine gas drilling declines and market conditions improve.

The Company s U.S. gas marketing activities are handled by Vintage Gas, Inc., its wholly-owned gas marketing affiliate. This marketing affiliate earns fees through the marketing of Company-produced gas 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.

The Company has entered into certain firm gas transportation and compression agreements in Bolivia whereby the Company has 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, the Company believes the risk of significant fluctuations is minimal. The Company entered into these arrangements to ensure its access to gas markets and currently expects 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 $2.7 million in 2003, $1.4 million in 2004, $0.3 million in 2005, $0.3 million in 2006, $0.3 million in 2007 and $0.6 million thereafter.

The Company has also entered into deliver-or-pay arrangements whereby the Company has 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, the Company must pay for the undelivered volumes at the then-current market price. Similar to the firm transportation and compression agreements, the Company entered into these arrangements to ensure its access to gas markets and currently expects to produce sufficient volumes to satisfy all of its deliver-or-pay obligations. The volumes contracted under the agreement in Bolivia are 11.1 Bcf in 2003, 10.3 Bcf in 2004, 6.0 Bcf in 2005, 5.8 Bcf in 2006, 6.0 Bcf in 2007 and 13.9 Bcf thereafter. The volumes contracted under the agreement in Argentina are 2.6 Bcf in 2003, 2.6 Bcf in 2004, 3.2 Bcf in 2005, 3.3 Bcf in 2006, 3.6 Bcf in 2007 and 3.9 Bcf thereafter.

The Company has previously engaged in oil and gas hedging activities and intends to continue to consider various hedging arrangements to realize commodity prices which it considers favorable. The Company has entered into various oil hedges (swap agreements) covering approximately 4.1 MMBbls at a weighted average price of $26.26 per Bbl (NYMEX reference price) for various periods of 2003. The Company has also entered into various gas hedges (swap agreements) covering approximately 20.1 million MMBtu of its gas production for calendar year 2003 at a weighted average NYMEX reference price of $4.02 per MMBtu. The Canadian portion of the gas swap agreements (approximately 9.1 million MMBtu) is at a weighted average NYMEX reference price of 6.63 Canadian dollars per MMBtu and will be settled in Canadian dollars. The U.S. portion of the gas swap agreements (approximately 11 million MMBtu) is at a weighted average NYMEX reference price of $4.00 per MMBtu. Additionally, the Company has entered into basis swap agreements for approximately 8.4 million MMBtu of its U.S. gas production covered by the gas swap agreements. These basis swaps establish a differential between the NYMEX reference price and the various delivery points at levels that are comparable to the historical differentials received by the Company. The Company continues to monitor oil and gas prices and 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, 2003	1,181,000	$27.32
June 30, 2003	1,152,000	27.18
September 30, 2003	936,000	25.37
December 31, 2003	874,000	24.55

The following table reflects the MMBtu hedged in the U.S. and the corresponding NYMEX reference price by quarter:

Quarter Ending	MMBtu	NYMEX Reference Price Per MMBtu
March 31, 2003	2,700,000	$4.20
June 30, 2003	2,730,000	3.86
September 30, 2003	2,760,000	3.88
December 31, 2003	2,760,000	4.04

The following table reflects the MMBtu hedged in Canada and the corresponding NYMEX reference price by quarter:

Quarter Ending	MMBtu	NYMEX Reference Price Per MMBtu
		(Canadian $)
March 31, 2003	2,250,000	C$7.09

June 30, 2003	2,275,000	6.42
September 30, 2003	2,300,000	6.39
December 31, 2003	2,300,000	6.64

The counterparties to the Company s current swap agreements are commercial or investment banks. The Company continues to monitor oil and gas prices and may enter into additional oil and gas hedges or swaps in the future.

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Gathering Systems and Plant

The Company owns 100 percent interests in two oil and gas gathering systems located in Pottawatomie County, Oklahoma and Harris and Chambers Counties, Texas. In addition, the Company owns 100 percent interests in seven gas gathering systems located in active, producing areas of California, Kansas, Texas and Oklahoma. All of these gathering systems are operated by the Company. Together, these systems comprise approximately 244 miles of varying diameter pipe. At December 31, 2002, there were 881 wells (813 of which are operated by the Company) connected to these systems. Generally, the gathering systems buy gas at the wellhead on the basis of a percentage of the resale price under contracts containing terms of one to ten years.

In 1999, the Company obtained ownership and operatorship of the Santa Clara Valley gas plant located in Ventura County, California. This plant is a 1980-vintage Randall skid-mounted cryogenic expander plant designed for 17 MMcf per day of inlet gas and is complete with inlet gas compression, mole sieve dehydration facilities, propane refrigeration, natural gas liquids product storage and truck loading. There are two inlet gas systems feeding the compressor units; one is a 30-pound system and the other is an 80-pound system. Sales line pressure is at 220 pounds and is obtained with a turbo-expander compressor. 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 the Company, primarily under wellhead gas purchase agreements.

Reserves

At December 31, 2002, the Company had proved reserves of 529.3 MMBOE, comprised of 348.7 MMBbls of oil and 1.1 Tcf of gas, as estimated by the independent petroleum consultants of Netherland, Sewell & Associates, Inc. for the U.S., Argentina and Ecuador, 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 the Company s oil and gas reserves, see Oil and Gas Properties. The following table sets forth, at December 31, 2002, the present value of future net revenues (revenues less production, development and abandonment costs) before income taxes attributable to the Company s proved reserves at such date (in thousands):

Proved Reserves:	
Future net revenues	$7,585,907
Present value of future net revenues before income taxes, discounted at 10 percent	4,009,322
Standardized measure of discounted future net cash flows	2,746,257
Proved Developed Reserves:	
Future net revenues	$4,664,248
Present value of future net revenues before income taxes, discounted at 10 percent	2,680,919

In computing this data, assumptions and estimates have been utilized, and the Company cautions against viewing this information as a forecast of future economic conditions. The historical 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, 2002, economic conditions. The estimated future production is valued at prices prevailing at December 31, 2002. The resulting estimated future gross revenues are reduced by estimated future costs to develop and produce the proved reserves and by estimated future abandonment costs, based on December 31, 2002, cost levels, but such costs do not include debt service, general and administrative expenses and income taxes.

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 the Company s consolidated financial statements included elsewhere in this Form 10-K.

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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 the Company s consolidated financial statements included elsewhere in this Form 10-K.

Productive Wells; Developed Acreage

The following table sets forth the Company s productive wells and developed acreage assignable to such wells at December 31, 2002:

	Developed Acreage		Productive Wells					
			Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
U.S.	465,507	339,860	2,743	2,497	824	509	3,567	3,006
Canada	435,092	217,880	232	171	488	311	720	482
Argentina	217,848	181,894	1,560	1,399	29	29	1,589	1,428
Bolivia	76,603	65,483			15	14	15	14
Ecuador	33,425	24,745	11	8			11	8
	1,228,475	829,862	4,546	4,075	1,356	863	5,902	4,938

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. The developed acreage and productive wells in Ecuador were sold on January 31, 2003. See Divestitures.

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Undeveloped Acreage

At December 31, 2002, the Company held the following undeveloped acres located in the U.S., Canada, Argentina, Bolivia, Ecuador, Yemen and other international areas. With respect to such U.S. acreage held under leases, 74,397 gross (40,254 net) acres are held under leases with primary terms that expire at varying dates through December 31, 2006, unless commercial production has commenced. With respect to such Canadian acreage held under leases, 1,818,197 gross (1,042,852 net) acres are held under leases with primary terms that expire at varying dates through December 31, 2006, unless commercial production has commenced. The Company has the option to relinquish portions of its undeveloped acreage in Argentina at various dates through 2007 or pay increased mining royalties. All of the Bolivian acreage is held under a concession that expires in 2003. If the Company s planned exploratory well in Bolivia for 2003 is successful, only 275,213 gross and net acres will expire in 2003. The acreage in Yemen is held under concessions with terms that expire in 2004. The undeveloped acreage in Ecuador was sold on January 31, 2003. See Divestitures.

State/Country	Gross Acres	Net Acres
California	4,965	4,872
Louisiana	8,315	3,250
New Mexico	2,883	2,434
North Dakota	10,392	6,793
Oklahoma	31,557	13,624
Texas	22,092	13,911
Total U.S.	80,204	44,884
Canada	2,122,450	1,176,049
Argentina	1,407,802	1,206,105
Bolivia	336,989	336,989
Ecuador	782,134	579,520
Yemen	831,014	623,261
Other International Areas	550,214	385,150
Total Company	6,110,807	4,351,958

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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,		
	2002	2001	2000
Production:			
Oil (MBbls)			
U.S.	6,796	8,409	9,044
Canada	1,829	1,539	19
Argentina (a)	10,942	10,548	9,406
Bolivia (b)	118	101	131
Continuing operations	19,685	20,597	18,600
Ecuador (c)	1,174	1,375	1,261
Trinidad		2	
Total	20,859	21,974	19,861
Gas (MMcf)			
U.S.	24,841	34,168	35,764
Canada	29,951	22,132	312
Argentina	8,630	10,253	8,705
Bolivia	6,424	9,088	8,948
Total	69,846	75,641	53,729
MBOE from continuing operations	31,326	33,204	27,555
Total MBOE	32,500	34,581	28,816
Average Price (including impact of hedges):			
Oil (per Bbl)			
U.S.	$ 21.78	$ 23.08	$ 22.85
Canada	21.62	20.55	26.05
Argentina	20.98(d)	21.80	28.25
Bolivia	20.73	20.06	29.62
Continuing operations	21.31(d)	22.22	25.63
Ecuador	20.46	17.65	24.27
Total	21.27(d)	21.93	25.55
Gas (per Mcf)			
U.S.	$ 2.85	$ 4.83	$ 3.91
Canada	2.48	2.50	5.73
Argentina	.37	1.30	1.79
Bolivia	1.54	1.72	1.75
Total	2.26	3.30	3.22
Average Price (excluding impact of hedges):			
Oil (per Bbl)			
U.S.	$ 22.66	$ 22.17	$ 26.95
Canada	21.62	20.55	26.05
Argentina	21.06(d)	20.66	28.25
Bolivia	20.73	20.06	29.62
Continuing operations	21.66(d)	21.27	27.62
Ecuador	20.46	17.65	24.27
Total	21.60(d)	21.04	27.41
Gas (per Mcf)			
U.S.	$ 2.94	$ 4.83	$ 3.91

Canada	2.49	2.50	5.73
Argentina	.37	1.30	1.79
Bolivia	1.54	1.72	1.75
Total	2.30	3.30	3.22

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	Years Ended December 31,		
	2002	2001	2000
Production Costs (per BOE):			
U.S.	$ 8.05	$ 7.56	$ 6.42
Canada	6.61	6.23	7.09
Argentina	5.40	4.98	4.87
Bolivia	3.64	2.71	2.33
Continuing operations	6.52	6.16	5.57
Ecuador	7.68	6.47	4.85
Total	6.56	6.18	5.54

(a) Production for Argentina for the years ended December 31, 2002, 2001 and 2000, before the impact of changes in inventories was 10,771 MBbls, 10,644 MBbls, and 9,512 MBbls, respectively.

(b) Production for Bolivia for the years ended December 31, 2002, 2001 and 2000, before the impact of changes in inventories was 95 MBbls, 125 MBbls and 119 MBbls, respectively.

(c) Production for Ecuador for the years ended December 31, 2002, 2001 and 2000, before the impact of changes in inventories was 1,191 MBbls, 1,375 MBbls and 1,227 MBbls, respectively.

(d) Reflects the impact of the one-time government-mandated forced settlement of domestic Argentine oil sales which decreased the Argentina, continuing operations and total average oil prices per Bbl for the year ended December 31, 2002, by $.73, $.41 and $.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 production taxes, export taxes, transportation and storage costs, maintenance and repairs, labor and utilities.

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Drilling Activity

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

	Years Ended December 31,					
	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
Development:						
United States						
Productive	2	1.42	16	7.40	21	14.93
Non-Productive			2	1.45	2	1.68
Canada						
Productive	39	28.70	47	33.40		
Non-Productive	10	8.40	7	6.80		
Argentina						
Productive	20	18.00	68	68.00	40	40.00
Non-Productive			1	1.00	1	1.00
Bolivia						
Productive						
Non-Productive						
Ecuador						
Productive	3	2.15	1	0.75		
Non-Productive						
Total	74	58.67	142	118.80	64	57.61
Exploratory:						
United States						
Productive	1	.35	7	4.44	14	6.17
Non-Productive	1	.25	4	2.53	4	2.02
Canada						
Productive	17	13.60	26	20.00		
Non-Productive	19	18.20	10	8.90	1	0.45
Bolivia						
Productive						
Non-Productive					3	3.00
Ecuador						
Productive						
Non-Productive					1	1.00
Yemen						
Productive	1	.75				
Non-Productive	1	.75			1	0.75
Trinidad						
Productive			2	0.72		
Non-Productive						

Total	40	33.90	49	36.59	24	13.39
Total:						
Productive	83	64.97	167	134.71	75	61.10
Non-Productive	31	27.60	24	20.68	13	9.90
Total	114	92.57	191	155.39	88	71.00

The above well information excludes wells in which the Company has only a royalty interest.

At December 31, 2002, the Company was a participant in the drilling, completion or evaluation of 13 gross (9.25 net) wells. All of the Company s drilling activities are conducted with independent contractors. The Company owns no drilling equipment.

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Seasonality

Historically, the results of operations of the Company 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, the Company 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.

Competition

Competition in the oil and gas industry is intense. Both in seeking to acquire desirable producing properties, new leases and exploration prospects and in marketing oil and gas, the Company faces 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 the Company. 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. The Company is dependent upon independent drilling contractors to furnish rigs, equipment and tools to drill the wells it operates. The Company has not experienced and does 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 planned projects.

Regulation

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, the Company is unable to predict the future cost or impact of complying with such regulations.

Exploration and Production. Exploration and production operations of the Company 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. The Company s 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 the Company can produce from its wells and the number of wells or the locations at which the Company can drill.

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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 exploration, development and production operations of the Company. For example, the discharge or substantial threat of a discharge of oil by the Company into U.S. waters or onto an adjoining shoreline may subject the Company 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 the Company. The Company s operations generally will be covered by insurance which the Company believes 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 liability the Company may incur. The Company is also subject to laws and regulations concerning occupational safety and health. It is not anticipated that the Company will be required in the near future to expend any amounts that are material in the aggregate to the Company s overall operations by reason of environmental or occupational safety and health laws and regulations, but because such laws and regulations are frequently changed, the Company is unable to predict the ultimate cost of compliance.

Certain of the Company s 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, the Company does 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 such shares in the Company by citizens of foreign countries who are not deemed to be reciprocal under such Act could have an impact on the Company s ownership of federal leases.

Marketing, Gathering and Transportation. Federal legislation and regulatory controls have historically affected the price of the gas produced and sold by the Company and the manner in which such 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 the Company, 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 the marketing activities of the Company.

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.

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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. Interstate transmission facilities are, on the other hand, 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 the Company s gathering facilities. While the FERC has not issued any order or opinion declaring the Company s facilities as gathering rather than transmission facilities, the Company believes 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. The Company s gathering systems could be adversely affected should they be subjected in the future to the application of such state regulation.

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.

The Company s operations in Argentina are subject to the laws and regulations established there. 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 the Company receives for oil and gas it produces and sells; (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) the Company s 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.

The Company s operations in Canada, Bolivia, Yemen and Italy 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 the Company s operations. The Company s Bolivian projects are dependent, in large part, on the continued market development of the Bolivia-to-Brazil gas pipeline.

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Risk Factors

The following risks and uncertainties should be carefully considered when reading this Form 10-K. If any of the events described below were to occur, they could have a material adverse effect on the Company s 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, the Company s financial results.

The Company s 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 the Company currently receives for its production are higher than their 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 the Company s cash flows and profitability. The substantial and extended decline in oil and gas prices during 1998 and 1999 adversely affected the Company s financial condition and results of operations. A sustained period of low prices could have a material adverse effect on the Company s 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 the Company s 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.

In addition, various factors may adversely affect the Company s ability to market its oil and gas production, including:

capacity and availability of oil and gas gathering systems and pipelines;

effects of 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 the Company s level of capital expenditures, reserve estimates and borrowing capacity.

Lower oil and gas prices, such as those experienced by the Company in 1998 and the first half of 1999, have various adverse effects on the Company s business, including reducing cash flows which, among other things, have caused the Company in the past, and may cause the Company in the future, to decrease its capital expenditures. A smaller capital expenditure program may adversely affect the Company s ability to increase or maintain its reserve and production levels. Lower prices may also result in reduced reserve estimates, one-time 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 the Company recorded a significant non-cash charge for the impairment of the Company s oil and gas properties due to lower oil and gas prices.

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

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

The Company currently has a significant amount of indebtedness. At December 31, 2002, the Company s total long-term debt outstanding was approximately $883 million and the Company had a long-term debt to total capitalization ratio of 60.5 percent. The Company s significant indebtedness could have important consequences. For example:

- the Company s 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 the Company s cash flows from operations must be utilized for the payment of interest on its indebtedness and will not be available for financing capital expenditures or other purposes; for example, interest payments for 2002 represented approximately 24 percent of the Company s cash flows from operations before working capital changes and interest expense;
- the Company s level of indebtedness and the covenants governing its current indebtedness could limit the Company s flexibility in planning for, or reacting to, changes in its business because certain financing options may be limited or prohibited;
- the Company is more highly leveraged than some of its competitors, which may place the Company at a competitive disadvantage;
- the Company s level of indebtedness may make it more vulnerable during periods of low oil and gas prices or in the event of a downturn in its business because of its fixed debt service obligations; and
- the terms of the Company s 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 the Company s outstanding senior and senior subordinated notes. In such event, the Company cannot provide assurance that it would have sufficient funds available or could obtain the financing required to meet its obligations.

The Company may be able to incur substantial additional indebtedness in the future. The Company s revolving credit facility would permit additional borrowings of up to approximately $284 million (considering outstanding letters of credit of approximately $15.9 million), as of February 28, 2003. For further discussion of the Company s borrowing base, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Resources and Liquidity. If the Company were to add additional indebtedness to its current debt levels, the related risks discussed above, which it now faces, could intensify.

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The Company s future performance depends upon its ability to find or acquire additional oil and gas reserves that are economically recoverable.

Unless the Company successfully replaces the reserves that it produces, its reserves will decline, eventually resulting in a decrease in oil and gas production and lower revenues and cash flows from operations. The Company has historically succeeded in substantially replacing reserves through acquisition, exploration and development. The Company has conducted such activities on its existing oil and gas properties as well as on newly acquired properties. The Company 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 the Company s cash flows and may cause it to reduce capital expenditures. The business of exploring for, developing or acquiring reserves is capital intensive. The Company may not be able to make the necessary capital investments to maintain or expand its oil and gas reserves if cash flows from operations is 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.

The Company is continually identifying and evaluating acquisition opportunities, including acquisitions that would be significantly larger than those it has consummated to date. The Company cannot ensure that it will successfully consummate any acquisition, that it will be able to acquire producing oil and gas properties that contain economically recoverable reserves or that any acquisition will be profitably integrated into its operations.

Acquisitions carry unknown risks including the potential for environmental problems.

The Company s focus on acquiring producing oil and gas properties may increase its potential exposure to liabilities and costs for environmental and other problems existing on such properties. The Company expects to continue to focus, as it has done in the past, on acquiring producing oil and gas properties to replace reserves. Although the Company performs reviews of the acquired properties that it believes are consistent with industry practice, such reviews are inherently incomplete. In general, it is not feasible to review in depth each individual property being acquired. Ordinarily, the Company focuses its review efforts on the higher-valued properties and samples 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 the Company 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 the Company s proved reserves and the present value of such estimates are based upon 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 uneconomic 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, the Company recorded a significant non-cash charge for the impairment of oil and gas properties in the fourth quarter of 1998 due to lower oil and gas prices and the Company recorded a significant non-cash charge for the impairment of oil and gas properties in the fourth quarter of 2002 due to reserve revisions that resulted from additional geological, geophysical and engineering information and from revised production projections.

The Company s 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 the Company s total assets. The Company has international operations in Canada, Argentina, Bolivia, Yemen and Italy. For 2002, the Company s operations in Argentina accounted for approximately 35 percent of the Company s revenues and 28 percent of its total assets. For 2002, the Company s operations in Canada accounted for approximately 17 percent of the Company s revenues and 32 percent of its total assets. During 2002, the Company s operations in Argentina and Canada represented its only foreign operations accounting for more than 10 percent of its revenues or total assets. The Company continues to identify and evaluate international opportunities, but currently has no binding agreements or commitments to make any material international investment. As a result of such significant foreign operations, the Company s 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.

The Company s foreign properties, operations or investments in Canada, Argentina, Bolivia, Yemen and Italy 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 the Company s foreign operations;
- exchange controls and currency fluctuations could result in financial losses;
- royalty and tax increases and retroactive tax claims could increase costs of the Company s foreign operations;
- expropriation of the Company s property could result in loss of revenue, property and equipment;
- civil uprisings, riots and wars could make it impractical to continue operations, adversely affect both budgets and schedules and expose the Company 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 the Company s ability to fund foreign operations or may make foreign operations more costly.

In particular, the Company s Bolivian projects are dependent, in large part, on the 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 the Company s control. In addition, in the event of a dispute arising from foreign operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of the courts in the U.S. The Company may also be hindered or prevented from enforcing its 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 the Company receives for oil and gas that it produces and sells;
- the timing of repatriations of cash to the U.S.;
- the amount of permitted export sales;
- the Argentine banking system;
- the Company s 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.

The Company s hedging activities may expose the Company to the risk of financial loss in certain circumstances.

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

- production is less than expected;
- a change in the difference between published price indexes established by pipelines in which the Company s hedged production is delivered and the reference price established in the hedging arrangements is such that the Company is required to make payments to the counterparties to the Company s arrangements; or
- the counterparties to the Company s hedging arrangements fail to honor their financial commitments.

The Company currently has contracts hedging 4.1 MBbls of oil for various periods in 2003 at an average NYMEX reference price of $26.26 per Bbl, contracts hedging 11.0 million MMBtu of U.S. gas for 2003 at a NYMEX reference price of $4.00 per MMBtu and contracts hedging 9.1 million MMBtu of Canadian gas for 2003 at a weighted average NYMEX reference price of 6.63 Canadian dollars per MMBtu.

Uninsured risks associated with the Company s operations could result in a substantial financial loss.

The Company s 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 the Company s operations and substantial losses to the Company. In accordance with customary industry practice, the Company maintains 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 the Company s financial position and results of operations.

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Governmental and environmental regulations could adversely affect the Company s business.

The Company s 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 the Company s oil and gas wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where the Company has production, could limit the total number of wells drilled or the allowable production from successful wells, which could decrease the Company s revenues.

The Company s operations are subject to complex environmental laws and regulations adopted by the various jurisdictions where the Company operates. The Company 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. The Company 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, the Company cannot ensure that laws and regulations enacted in the future, including changes to existing laws and regulations, will not adversely affect the Company s business. In addition, because the Company acquires interests in properties that have been previously operated by others, the Company may be liable for environmental damage caused by such former operators.

Industry competition may impede the Company s growth.

The oil and gas industry is highly competitive, and the Company may not be able to compete successfully or grow its business. The Company competes 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. The Company also competes 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 the Company. The Company may not be able to successfully expand its business or attract or retain qualified employees.

Employees

The Company employs approximately 227 full-time people in its Tulsa office whose functions are associated with management, engineering, geology, land, legal, accounting, financial planning and administration. In addition, approximately 159 full-time employees are responsible for the supervision and operation of its U.S. field activities. The Company also employs approximately 304 people for the management and operation of its properties in Canada, Argentina, Bolivia and Yemen. The Company believes its relations with its employees are excellent.

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Item 3. Legal Proceedings.

The Company is a named defendant in lawsuits and is 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 the Company cannot be predicted with certainty, management does not expect these matters to have a material adverse effect on the Company s financial position or results of operations.

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

There were no matters submitted to the Company s stockholders during the fourth quarter of the fiscal year ended December 31, 2002.

Item 4A. Executive Officers of the Registrant.

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

Name	Age	Position
Charles C. Stephenson, Jr.	66	Director and Chairman of the Board of Directors
S. Craig George	50	Director, President and Chief Executive Officer
William L. Abernathy	51	Director, Executive Vice President and Chief Operating Officer
William C. Barnes	48	Director, Executive Vice President, Chief Financial Officer, Secretary and Treasurer
William E. Dozier	50	Senior Vice President Business Development
Kellam Colquitt	55	Vice President Exploration
Robert W. Cox	57	Vice President General Counsel
J. Chris Jacobsen	47	Vice President U.S. Operations
Andy R. Lowe	51	Vice President Marketing
Michael F. Meimerstorf	46	Vice President and Controller
Robert E. Phaneuf	56	Vice President Corporate Development
Larry W. Sheppard	48	Vice President New Ventures
Martin L. Thalken	42	Vice President Acquisitions
Gary A. Watson	45	Vice President Canadian Operations

Mr. Stephenson, a co-founder of the Company, has been a Director since June 1983 and Chairman of the Board of Directors of the Company since April 1987. He was also Chief Executive Officer of the Company from April 1987 to March 1994 and President of the Company 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 43 years of oil and gas experience.

Mr. George has been a Director since October 1991, President of the Company since September 1995 and Chief Executive Officer of the Company since December 1997. He was also Chief Operating Officer of the Company from March 1994 to December 1997, an Executive Vice President of the Company from March 1994 to September 1995 and a Senior Vice President of the Company from October 1991 to March 1994. From April 1991 to October 1991, Mr. George was Vice President of Operations and International with Santa Fe Minerals, Inc., an independent oil and gas company (Santa Fe Minerals). From May 1981 to March 1991, he served in various other management and executive capacities with Santa Fe Minerals and its subsidiary, Andover. From December 1974 to April 1981, Mr. George held various management and engineering positions with Amoco Production Company. He has a B.S. Degree in Mechanical Engineering from the University of Missouri-Rolla.

Mr. Abernathy has been a Director since October 1999, and an Executive Vice President and Chief Operating Officer of the Company since December 1997. He was Senior Vice President Acquisitions of the Company from March 1994 to December 1997, Vice President Acquisitions of the Company from May 1990 to March 1994 and Manager Acquisitions of the Company 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, Treasurer and Secretary of the Company since April 1987, an Executive Vice President of the Company since March 1994 and Chief Financial Officer of the Company since May 1990. He was also a Senior Vice President of the Company from May 1990 to March 1994 and Vice President Finance of the Company 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.

Mr. Dozier has been Senior Vice President Business Development since November 2002. He was Senior Vice President Operations of the Company from December 1997 to November 2002 and from May 1992 to December 1997, he was Vice President Operations of the Company. From June 1983 to April 1992, he was employed by 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. Colquitt has been Vice President Exploration of the Company since May 2001. From April 2000 to May 2001, he was General Manager North American Exploration of the Company. 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 Vice President General Counsel of the Company 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. Jacobsen has been Vice President U.S. Operations of the Company 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.

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Mr. Lowe has been Vice President Marketing of the Company since December 1997. He was General Manager Marketing of the Company 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.

Mr. Meimerstorf, a certified public accountant, has been Controller of the Company since January 1988 and a Vice President of the Company since May 1990. He was Accounting Manager of the Company 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 Vice President Corporate Development of the Company 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. Sheppard has been Vice President New Ventures of the Company since May 2001. From November 1994 to May 2001, he was Vice President International of the Company. 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. Thalken has been Vice President Acquisitions of the Company since December 1997. He was Acquisitions Technical Manager of the Company from May 1995 to December 1997 and an acquisitions engineer with the Company from January 1992 to May 1995. From October 1990 to December 1991, he was employed by Enron Oil and Gas Company, serving as a production engineer. From May 1983 to September 1990, he was employed by Exxon Company USA, in various engineering and supervisory capacities. He has a B.S. Degree in Mechanical Engineering from the University of Kansas.

Mr. Watson has been Vice President Canadian Operations of the Company since June 2001. He was General Manager Latin American Operations of the Company 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.

The Company s 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 the Company s common stock, as reported in the New York Stock Exchange composite transactions, and the cash dividends paid per share of common stock for the periods indicated:

	High	Low	Dividends Paid
2002			
First Quarter	$ 14.70	$ 7.85	$ .035
Second Quarter	14.96	10.61	.035
Third Quarter	11.80	8.10	.040
Fourth Quarter	11.50	8.32	.040
2001			
First Quarter			