VINTAGE PETROLEUM INC
Form 10-K
March 12, 2004
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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, 2003

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ________ to ________

Commission file number 1-10578

VINTAGE PETROLEUM, INC.

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the Registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

Indicate by check mark whether the Registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes x No ¨

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

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

DOCUMENTS INCORPORATED BY REFERENCE

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

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VINTAGE PETROLEUM, INC.

FORM 10-K

YEAR ENDED DECEMBER 31, 2003

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Certain Definitions

As used in this Form 10-K:

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

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

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

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

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

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

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

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

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Forward-Looking Statements

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

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

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

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

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

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

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

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PART I

Items 1 and 2. Business and Properties.

Website Access to Reports

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

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

General

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

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

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

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

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

Business Strategy

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

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

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

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

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

Acquisitions

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

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

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

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

Divestitures

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

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

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

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Exploration and Development

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Oil and Gas Properties

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Marketing

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Gathering Systems and Plant

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

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

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

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Reserves

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

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

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

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

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

The reserve data set forth in this Form 10-K represent estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimate. Accordingly, reserve estimates often differ from the quantities of oil and gas that are ultimately recovered. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they were based.

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

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Productive Wells; Developed Acreage

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

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

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

Undeveloped Acreage

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

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

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

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

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Production; Unit Prices; Costs

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

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

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

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

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

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

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

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

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

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Drilling Activity

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

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

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

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

Seasonality

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

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Competition

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

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

Regulation

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

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

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

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

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

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

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

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

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

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

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

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

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

Risk Factors

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

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

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

Prices for oil and gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors that are beyond our control, including:

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

- domestic and foreign supplies of oil and gas;
- levels of consumer demand;
- weather conditions;
- domestic and foreign government regulations;
- prices and availability of alternative fuels; and
- overall economic conditions.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Acquisitions carry unknown risks including the potential for environmental problems.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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Governmental and environmental regulations could adversely affect our business.

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

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

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

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

Industry competition may impede our growth.

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

Employees

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

Item 3. Legal Proceedings.

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

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

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

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Item 4A. Executive Officers of the Registrant.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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PART II

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

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

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

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

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

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

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Item 6. Selected Financial Data.

SELECTED FINANCIAL AND OPERATING DATA

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

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

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

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

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

Overview

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

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

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

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

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

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

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

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Results of Operations

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

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

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

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

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

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	Years Ended December 31,		
	2003	2002	2001
Average Sales Price (including impact of hedges):			
Oil (per Bbl) -			
U.S.	$ 24.98	$ 21.78	$ 23.08
Canada	28.18	21.62	20.55
Argentina	26.14	20.98[(a)]	21.80
Bolivia	23.04	20.73	20.06
Continuing operations	25.87	21.31[(a)]	22.22
Ecuador	26.87	20.46	17.65
Total	25.88	21.27[(a)]	21.93
Gas (per Mcf) -			
U.S.	$ 4.20	$ 2.85	$ 4.83
Canada	4.35	2.48	2.50
Argentina	0.46	0.37	1.30
Bolivia	2.01	1.54	1.72
Total	3.38	2.26	3.30
Average Sales Price (excluding impact of hedges):			
Oil (per Bbl) -			
U.S.	$ 28.23	$ 22.66	$ 22.17
Canada	27.90	21.62	20.55
Argentina	26.14	21.06[(a)]	20.66
Bolivia	23.04	20.73	20.06
Continuing operations	26.98	21.66[(a)]	21.27
Ecuador	26.87	20.46	17.65
Total	26.98	21.60[(a)]	21.04
Gas (per Mcf) -			
U.S.	$ 4.81	$ 2.94	$ 4.83
Canada	4.67	2.49	2.50
Argentina	0.46	0.37	1.30
Bolivia	2.01	1.54	1.72
Total	3.73	2.30	3.30

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

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Oil Prices

Average U.S. and Canada oil prices we receive generally fluctuate with changes in the NYMEX reference price for oil. Our oil production in Argentina is sold 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 2003, we experienced a 21 percent increase in our average oil price from continuing operations, including the impact of hedging activities (25 percent increase excluding hedging activities), compared to 2002. We experienced a three percent decrease in our average oil price from continuing operations, including the impact of hedging activities (two percent increase excluding hedging activities) in 2002 compared to 2001. Our realized average oil price from continuing operations for 2003 (before hedges) was approximately 87 percent of the NYMEX reference price, compared to 83 percent in 2002 and 81 percent in 2001.

As discussed in Note 1 to our consolidated financial statements included elsewhere in this Form 10-K, the Argentine government took actions which in effect caused the devaluation of the peso in early December 2001 and, in February 2002, enacted an emergency law that, in part, required certain contracts that were previously payable in U.S. dollars to be payable in pesos. Subsequently, on February 13, 2002, the Argentine government announced a 20 percent tax on oil exports, effective March 1, 2002. The tax of 20 percent is applied on the sales value after the tax, thus the net effect is 16.7 percent. The export tax is not deducted in the calculation of royalty payments. The tax is limited by law to a maximum term of five years. For additional information, see Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Foreign Currency and Operations Risk included elsewhere in this Form 10-K. Domestic Argentine oil sales, while valued in U.S. dollars, are now being paid in pesos. Export oil sales continue to be valued and paid in U.S. dollars.

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

On January 2, 2003, at the Argentine government s request, crude oil producers and refiners agreed to limit amounts payable for domestic sales occurring during the first quarter of 2003 to a maximum $28.50 per Bbl. The producers and refiners further agreed that the difference between the actual price and the maximum price would be payable once actual prices fell below the maximum. 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 maximum price. Additionally, the agreement allowed for renegotiation if the West Texas Intermediate reference price exceeded $35.00 per Bbl for 10 consecutive days, which occurred on February 24, 2003.

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 maximum 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. This agreement has been extended to February 29, 2004, and we believe that it will be further extended to April 30, 2004, during the coming weeks. We sold approximately 1.4 MMBbls of our net Argentine oil production (approximately 14 percent of our Argentina production) under this agreement during 2003. We have not recorded revenue nor a receivable for any amounts above the $28.50 maximum that have not yet been received. Repayments received from refiners will be recorded as revenue when received.

We participated in oil hedges covering 4.9 MMBbls, 4.9 MMBbls and 5.5 MMBbls in 2003, 2002 and 2001, respectively. The impacts of these oil hedges on our average oil prices are reflected in the preceding tables.

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Gas Prices

Average U.S. gas prices we receive generally fluctuate with changes in spot market prices, which may vary significantly by region, as evidenced by the significantly higher gas prices in California during the first half of 2001 due to the localized power shortage. Our gas in Canada is generally sold at spot market prices as reflected by the AECO gas price index. Most of our Bolivian gas production is sold at average gas prices tied to a long-term contract under which the base price is adjusted for changes in specified fuel oil indexes. Our Argentine gas is sold under spot contracts of varying lengths, which, as a result of the emergency law enacted in January 2002, are now paid in pesos. This has initially 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. Our total average gas price for 2003 was 50 percent higher than 2002, including the impact of hedging activities (62 percent higher excluding hedging activities), and for 2002 was 32 percent lower than for 2001, including the impact of hedging activities (30 percent lower excluding hedging activities).

We participated in gas hedges covering 20.1 million MMBtu and 13.5 million MMBtu in 2003 and 2002, respectively. The impacts of these gas hedges on our average gas prices are reflected in the preceding tables. We did not participate in any gas hedges in 2001.

Future Period Hedges

We have previously engaged in oil and gas hedging activities and we intend to continue to consider various hedging arrangements to realize commodity prices which we consider favorable. We have entered into various oil hedges (swap agreements) covering approximately 6.7 MMBbls of our North America production at a weighted average price of $28.77 per Bbl (NYMEX reference price) for various periods in 2004 and 2005. For additional information, see Items 1 and 2. Business and Properties - Marketing included elsewhere in this Form 10-K. The counterparties to our current hedging arrangements are commercial or investment banks. We continue to monitor oil and gas prices and may enter into additional oil and gas hedges or swaps in the future.

Relatively modest changes in either oil or gas prices significantly impact our results of operations and cash flows. However, the impact of changes in the market prices for oil and gas on our average realized prices may be reduced from time to time based on the level of our hedging activities. Based on 2003 oil production from continuing operations, a change in the average oil price we realize, before hedges, of $1.00 per Bbl would result in a change in net income and revenues less production and export taxes on an annual basis of approximately $10.0 million and $15.9 million, respectively. A $0.10 per Mcf change in the average gas price we realize, before hedges, would result in a change in net income and revenues less production and export taxes on an annual basis of approximately $3.6 million and $5.7 million, respectively, based on 2003 gas production from continuing operations.

Period to Period Comparisons

The period to period comparisons presented below are significantly affected by acquisitions and dispositions we made during the periods.

In May 2001, we purchased of 100 percent of the outstanding common stock of Genesis. Our consolidated revenues and expenses for the year ended December 31, 2001, include, under the purchase method of accounting, the consolidation of the revenues and expenses of Genesis for the last eight months of 2001.

On July 30, 2002, we completed the sale of our operations in Trinidad. We received $40 million in cash and recorded a gain of approximately $31.9 million ($14.9 million after income taxes). On January 31, 2003, we completed the sale of our operations in Ecuador. We received $137.4 million in cash and recorded a gain of approximately $47.3 million ($9.5 million after income taxes). In accordance with the rules established by Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS 144), our operations in Trinidad and Ecuador, along with the gains on the sales, are accounted for as discontinued operations in our consolidated financial statements. ***Accordingly, the revenues and operating expenses discussed below exclude the results related to our operations in Trinidad and Ecuador for all periods.***

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Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

We reported a net loss of $240.9 million for the year ended December 31, 2003, compared to a net loss of $143.7 million for the same period in 2002. The net loss for the year ended December 31, 2003, included:

- a non-cash charge of $370.2 million ($277.6 million net of tax) for the impairment of certain proved oil and gas properties, primarily in Canada;
- a non-cash charge of $25.7 million for the impairment of Canadian goodwill;
- a gain of $11.2 million ($7.1 million net of tax) for the cumulative effect of a change in an accounting principle for the adoption of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, (SFAS 143);
- a loss on early extinguishment of debt of $6.9 million ($4.2 million net of tax);
- a net loss on disposition of assets of $1.7 million ($1.0 million net of tax); and
- income from discontinued operations of $49.1 million ($10.8 million net of tax).

The net loss for the year ended December 31, 2002, included:

- a non-cash charge of $98.7 million ($57.7 million net of tax) for the impairment of certain proved oil and gas properties, primarily in Canada;
- a non-cash charge of $76.4 million for the impairment of Canadian goodwill;
- a loss of $60.5 million for the cumulative effect of a change in an accounting principle for the adoption of Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* (SFAS 142);
- a loss on early extinguishment of debt of $8.2 million ($5.0 million net of tax);
- a net gain on disposition of assets of $16.5 million ($10.1 million net of tax); and
- income from discontinued operations of $41.3 million ($22.1 million net of tax).

Oil and gas sales increased by $83.2 million (14 percent), to $660.9 million for 2003 from $577.7 million for 2002. A 21 percent increase in average oil prices more than offset a nine percent decrease in our oil production, resulting in an increase in oil sales of $44.0 million (10 percent) for 2003 as compared to 2002. Similarly, gas revenues increased by $39.2 million (25 percent) primarily as a result of a 50 percent increase in average gas prices, offset by a 16 percent decrease in our gas production. Our production on a BOE basis decreased 12 percent, resulting from our U.S. property sales in June 2002 and March 2003, our Canadian property sales in June and July 2003, natural production declines and the effects of substantially curtailed capital expenditures in 2002 which resulted in significantly lower production levels at the beginning of 2003. Capital expenditures in 2002 were limited to $129.7 million, or approximately 54 percent of cash flow provided by operating activities, as a result of our decision to use a portion of our cash flow and proceeds from asset sales to execute our debt reduction program in 2002.

Revenues and expenses for oil and gas gathering and processing and gas marketing increased significantly from 2002 to 2003 primarily due to an increase in U.S. gas prices.

A net loss on disposition of assets of $1.7 million ($1.0 million net of tax) was reflected in 2003 related to sales of certain U.S. Mid-Continent gas properties and certain non-strategic oil and gas assets in Saskatchewan and West Central Alberta, Canada. Total proceeds from these sales were $57.9 million. In 2002, we recorded a net gain on disposition of assets of $16.5 million ($10.1 million net of tax) primarily related to the sale of our heavy oil properties in the Santa Maria area of Southern California. The 2002 gain included the reversal of our accrual for future abandonment costs related to the sold properties.

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In 2003, we recorded a foreign currency exchange loss of $6.0 million compared to a gain of $0.4 million in 2002. As discussed in Note 1 to our consolidated financial statements included elsewhere in this Form 10-K, the Argentine government took actions which, in effect, caused the devaluation of the peso in early December 2001. The translation of peso-denominated balances at December 31, 2003, and peso-denominated transactions during the year then ended resulted in a foreign currency exchange loss of $6.6 million, partially offset by a gain of $0.6 million resulting from certain transactions denominated in U.S. dollars related to our Canadian operations. This loss was caused by the strengthening of the peso from a rate of 3.38 pesos to one U.S. dollar at December 31, 2002, to a rate of 2.94 pesos to one U.S. dollar at December 31, 2003. The translation of peso-denominated balances at December 31, 2002, and peso-denominated transactions during the year then ended resulted in a foreign currency exchange gain of $0.3 million included in the statement of operations. During 2002, the peso declined in value falling from a rate of 1.65 pesos to one U.S. dollar at January 11, 2002, to 3.38 pesos to one U.S. dollar at December 31, 2002. Included in Other income (expense) for 2002 was a gain of $0.9 million related to the Argentine government-mandated negotiated settlement of U.S. dollar-denominated receivables and payables in existence at January 6, 2002.

Production costs increased by $6.9 million (four percent) from $163.0 million in 2002 to $169.9 million in 2003. The increase is primarily the result of higher costs (expressed in U.S. dollars) in Argentina resulting from peso inflation and strengthening of the peso relative to the U.S. dollar and in Canada resulting from the strengthening of the Canadian dollar relative to the U.S. dollar. This increase was partially offset by reductions in expenses from property sales in the U.S. and Canada in 2002 and 2003. The 2003 costs also include $2.6 million for costs to repair damage resulting from the fires in California during the fourth quarter of 2003. The higher costs, along with the 12 percent decline in production on a BOE basis, increased production costs per BOE by $0.95 (18 percent) to $6.15 in 2003 from $5.20 in 2002.

Production, export and ad valorem taxes increased by $8.7 million (21 percent) from $41.3 million in 2002 to $50.0 million in 2003. This increase was primarily the result of the higher oil and gas prices we received in 2003 compared to 2002, which increased production and export taxes since they are based on sales values.

Exploration costs increased $32.2 million (75 percent), to $74.9 million for 2003 from $42.7 million for 2002. During 2003, our exploration costs included $45.9 million for unproved leasehold impairments, primarily in Canada, $15.0 million for unsuccessful exploratory drilling and $14.0 million for seismic and other geological and geophysical costs. Exploration costs for 2002 included $12.2 million for unproved leasehold impairments, $20.5 million for unsuccessful exploratory drilling and $10.0 million for seismic and other geological and geophysical costs. Exploration costs for 2003 included $23.7 million to fully impair our unproved leaseholds in the Northwest Territories.

General and administrative expenses increased $9.1 million (19 percent), to $57.1 million for 2003 from $48.0 million for 2002. Expenses increased primarily due to Argentine asset taxes and cash bonuses in 2003 with no comparable amounts in 2002. These increases, along with the 12 percent decline in production on a BOE basis, increased our general and administrative expenses per BOE from $1.53 in 2002 to $2.07 in 2003.

Stock compensation expense relates primarily to restricted stock awards. We granted approximately 1.2 million and 417,000 restricted stock awards in 2003 and 2002, respectively. These awards generally vest over a one to three year period and the compensation expense is amortized over the vesting period. The 2003 grants include 563,000 restricted stock awards that were issued in exchange for options to purchase 2.1 million shares of our common stock. Also, in 2003, we began expensing stock options on a prospective basis and recorded expense of $0.1 million in 2003 with no corresponding amount in 2002.

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Depreciation, depletion and amortization decreased $35.2 million (20 percent) to $143.7 million for 2003 from $178.9 million for 2002. In addition to the impact of the 12 percent decrease in production on a BOE basis, our average oil and gas amortization rate per equivalent barrel produced decreased from $5.55 in 2002 to $5.05 in 2003. These decreases primarily resulted from the impact that substantially higher product prices in 2003 had in increasing proved reserves used to determine the amortization rate, the decrease in Canadian production, which has a significantly higher amortization rate per BOE, and, to a lesser degree, from our mandated adoption of SFAS 143, effective January 1, 2003. Previously, we accrued an undiscounted estimate of future abandonment costs of wells and related facilities through our depreciation calculation in accordance with the provisions of Statement of Financial Accounting Standards No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, (SFAS 19) and industry practice. With the adoption of SFAS 143, we have now recorded a discounted fair value of the future retirement obligation as a liability with a corresponding amount capitalized as part of the related property s carrying amount. The discounted capitalized asset retirement cost is amortized to expense through the depreciation calculation over the estimated useful life of the asset based on proved developed reserves. The liability accretes over time with a charge to accretion expense, which was $7.3 million for 2003. As a result of the implementation of SFAS 143, we recorded a non-cash gain of $11.2 million ($7.1 million net of tax) as a cumulative effect of change in accounting principle.

We recorded impairments of proved oil and gas properties of $370.2 million in 2003, compared to $98.7 million in 2002. Both years impairments were primarily a result of oil and gas reserve revisions on our Canadian properties. Overall, the results in Canada during 2003 were disappointing, leading to significant downward reserve revisions at year end 2003. Results of our work programs and production performance of certain producing properties during the latter part of 2003 resulted in revisions to reserves previously booked to specific wells or to reserves associated with future activities. Due to these disappointing results, in connection with our normal year end reserve estimation process, we performed a critical review to revise or re-validate all remaining future activities on our Canadian proved reserve base. As a result of this review, we determined that previously planned exploration and development activities would be scaled back or eliminated. We continue to employ independent third party engineering firms to prepare estimates of our reserves in all of our operating areas.

We review our proved properties for impairment on a field basis and we recognize an impairment whenever events or circumstances (such as declining oil and gas prices or downward reserve revisions) indicate that the properties carrying values may not be recoverable. If an impairment is indicated based on our estimated future net revenues for total proved and risk-adjusted probable and possible reserves on a field basis, then a provision is recognized to the extent that the carrying value exceeds the present value of the estimated future net revenues (fair value). Due to the volatility of oil and gas prices, it is possible that our assumptions regarding oil and gas prices may change in the future. If in the future, price expectations are reduced or estimated proved reserves are revised downward, it is possible that additional significant impairment provisions for proved oil and gas properties would be required.

Interest expense decreased $7.8 million (10 percent) to $69.9 million for 2003 from $77.7 million for 2002 due to a 21 percent reduction in our average debt outstanding from 2002 to 2003.

In conjunction with the issuance of our 8 1/4% senior notes, we redeemed a portion of our 9% senior subordinated notes. We were required to expense certain associated deferred financing costs and discounts. This $5.2 million non-cash charge, along with a $3.0 million cash charge for the call premium on the 9% senior subordinated notes, resulted in a charge of $8.2 million in 2002. During 2003, we advanced funds under our revolving credit facility to redeem the remainder of our 9% senior subordinated notes and redeem the entire principal balance of our 8 5/8% senior subordinated notes. As a result, we were required to expense the remaining associated deferred financing costs and discounts. This $3.0 million non-cash charge and a $3.9 million cash charge for the call premium on the redemption of these notes resulted in a charge of $6.9 million in 2003.

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Effective January 1, 2002, we adopted the provisions of SFAS 142. SFAS 142 changed the accounting for goodwill from an amortization method to an impairment-only method. We tested goodwill for impairment in conjunction with a transitional goodwill impairment test in 2002. As a result of the transitional impairment test, we recorded a $60.5 million charge as a cumulative effect of change in accounting principle retroactive to January 1, 2002, in accordance with the provisions of SFAS 142. Decreases in oil and gas price expectations from the May 2, 2001, acquisition of Genesis to January 1, 2002, and certain downward revisions recorded to our Canadian oil and gas reserves at December 31, 2001, were the primary factors that led to the goodwill impairment at January 1, 2002. Additionally, the annual impairment tests as of December 31, 2003 and 2002, resulted in additional charges of $25.7 million and $76.4 million in 2003 and 2002, respectively. Certain downward revisions recorded to our Canadian oil and gas reserves in the fourth quarters of 2002 and 2003 were the primary reason for the additional goodwill impairments. As of December 31, 2003, we have no remaining goodwill recorded on our balance sheet.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

We reported a net loss of $143.7 million for the year ended December 31, 2002, compared to net income of $133.5 million for the same period in 2001. The net loss for the year ended December 31, 2002, included:

- a non-cash charge of $98.7 million ($57.7 million net of tax) for the impairment of certain proved oil and gas properties, primarily in Canada;
- a non-cash charge of $76.4 million for the impairment of Canadian goodwill;
- a loss of $60.5 million for the cumulative effect of a change in an accounting principle for the adoption of SFAS 142;
- a loss on early extinguishment of debt of $8.2 million ($5.0 million net of tax);
- a net gain on disposition of assets of $16.5 million ($10.1 million net of tax); and
- income from discontinued operations of $26.3 million ($22.1 million net of tax).

Net income for the year ended December 31, 2001, included:

- a non-cash charge of $29.0 million ($17.9 million net of tax) for the impairment of certain proved oil and gas properties;
- a net gain on disposition of assets of $26.9 million ($16.7 million net of tax); and
- income from discontinued operations of $9.1 million ($7.1 million net of tax).

In addition, a decrease in production and lower realized oil and gas prices, combined with higher exploration costs and interest expense, contributed to a decline in net income from 2001 to 2002.

Oil and gas sales decreased $129.4 million (18 percent), to $577.7 million for 2002 from $707.1 million for 2001. An eight percent decrease in our gas production, coupled with a 32 percent decrease in average gas prices, accounted for a $91.3 million decrease in gas sales for 2002 as compared to 2001. A four percent decrease in average oil prices combined with a four percent decrease in our oil production accounted for a $38.1 million decrease in oil sales for 2002 as compared to 2001. The four percent decrease in oil production and the eight percent decrease in gas production are from the combined effects of our non-strategic asset sales in the U.S. during the fourth quarter of 2001 and second quarter of 2002, natural production declines and the impact of a reduced capital spending program in 2002, which was curtailed in order to provide funds for debt reduction. These decreases were partially offset by increases in production in Canada and Argentina related to acquisitions during the second and third quarter of 2001.

Revenues and expenses for oil and gas gathering and processing and gas marketing decreased significantly from 2001 to 2002 primarily due to a decrease in U.S. gas prices.

A gain on disposition of assets of $16.5 million ($10.1 million net of tax) was reflected in 2002 primarily as a result of $15.5 million in proceeds from divestitures of our heavy oil properties in the Santa Maria area of southern California in June 2002. Included in the gain is the reversal of our accrual for future abandonment costs related to these properties. In 2001, we recorded a gain on disposition of assets of $26.9 million ($16.7 million net of tax).

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As discussed in Note 1 to our consolidated financial statements included elsewhere in this Form 10-K, the Argentine government took actions which, in effect, caused the devaluation of the peso in early December 2001. The translation of peso-denominated balances at December 31, 2001, and peso-denominated transactions during December 2001 increased 2001 net income by approximately $3.3 million, consisting of a foreign currency exchange gain of approximately $2.3 million and approximately $1.0 million in reductions of certain operating expenses. During 2002, the peso continued to decline in value falling from a rate of 1.65 pesos to one U.S. dollar at January 11, 2002, to 3.38 pesos to one U.S. dollar at December 31, 2002. The translation of peso-denominated balances at December 31, 2002, and peso-denominated transactions for the year then ended resulted in a foreign currency exchange gain of $0.3 million. We also recorded a gain of $0.9 million in Other income (expense) for 2002 related to the Argentine government-mandated negotiated settlement of U.S. dollar-denominated receivables and payables in existence at January 6, 2002.

Production coss decreased $19.3 million (11 percent) to $163.0 million in 2002 from $182.3 million in 2001. This decrease was primarily the result of our U.S. property sales in late 2001 and the beneficial impact of the Argentine peso devaluation on peso-denominated costs. Production costs per BOE decreased five percent to $5.20, compared to $5.49 in 2001, primarily as a result of the beneficial impact of the Argentine peso devaluation on peso-denominated costs.

Production, export and ad valorem taxes increased $19.0 million (85 percent) to $41.3 million in 2002 from $22.3 million in 2001. The tax imposed in 2002 on Argentine oil exports resulted in an expense of $24.0 million in 2002, with no corresponding amount in 2001. This increase was partially offset by the effect of lower production and lower oil and gas prices received in 2002 compared to 2001.

Exploration costs increased $21.1 million (98 percent), to $42.7 million for 2002 from $21.6 million for 2001. During 2002, our exploration costs included $32.7 million for unsuccessful exploratory drilling and lease impairments, primarily in North America and Yemen, and $10.0 million for seismic and other geological and geophysical costs. Exploration costs for 2001 included $12.0 million for unsuccessful exploratory drilling and lease impairments, primarily in North America, and $9.6 million for seismic and other geological and geophysical costs.

We recognized impairments of oil and gas properties of $98.7 million ($57.7 million net of tax) in 2002, compared to $29.1 million ($17.9 million net of tax) in 2001. The 2002 impairments were primarily a result of oil and gas reserve revisions on certain of our Canadian properties in the fourth quarter of 2002.

General and administrative expenses increased $0.3 million (one percent), to $48.0 million for 2002 from $47.7 million for 2001. Increases in Canada as a result of having a full year of operations for Genesis in 2002 compared to only eight months in 2001 were partially offset by a reduction of expenses in Argentina resulting from the beneficial impact of the Argentine peso devaluation on peso-denominated costs. General and administrative expenses per equivalent barrel produced increased to $1.53 for 2002 from $1.44 for 2001, primarily as a result of the six percent decrease in production on an equivalent barrel basis.

Depreciation, depletion and amortization increased $12.9 million (eight percent), to $178.9 million for 2002 from $166.0 million for 2001, due primarily to the 14 percent increase in the average amortization rate per equivalent barrel produced from $4.86 in 2001 to $5.55 in 2002. The amortization rate increase is primarily due to the acquisition of Genesis and the impact of lower commodity prices in 2002 on proved reserves used to determine the amortization rate.

Interest expense increased $13.0 million (20 percent), to $77.7 million for 2002 from $64.7 million for 2001, due primarily to a 22 percent increase in our total average outstanding debt year over year, primarily resulting from the acquisition of Genesis in May 2001 and an acquisition in Argentina during the third quarter of 2001. This increase was partially offset by a decrease in our average interest rate to 7.50 percent in 2002 as compared to 7.58 percent in 2001.

In conjunction with the issuance of our 8 1/4% senior notes, we entered into a new revolving credit facility and redeemed a portion of our 9% senior subordinated notes. We were required to expense certain associated deferred financing costs and discounts. This $5.2 million non-cash charge, along with a $3.0 million cash charge for the call premium on the 9% senior subordinated notes, resulted in a one-time charge of approximately $8.2 million ($5.0 million net of tax) in 2002.

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Cash Flows

Our primary sources of cash during 2003 were funds generated from operations and proceeds from the sales of certain oil and gas assets. The cash was primarily used to reduce long-term debt, fund capital expenditures and pay dividends with the remainder increasing our cash position by $45.6 million. See below for additional discussion of our cash flows from operating activities.

	Years Ended December 31,		
	2003	2002	Change
	(in thousands)		
Cash provided (used) by:			
Operating activities - continuing operations	$ 273,645	$ 226,771	$ 46,874
Operating activities - discontinued operations	(39,812)	14,098	(53,910)
Investing activities - continuing operations	1,126	(61,042)	62,168
Investing activities - discontinued operations	10,309	(13,211)	23,520
Financing activities	(201,891)	(161,913)	(39,978)

Cash provided by continuing operations increased 21 percent to $273.6 million in 2003 versus $226.8 million in 2002 primarily as a result of significantly higher oil and gas prices. The impact of higher prices was partially offset by a decline in production and higher operating costs. See Results of Operations and Period to Period Comparisons for further discussion. We did not see a significant difference between years in cash provided or used by changes in working capital amounts. Cash used by operating activities - discontinued operations for 2003 represents the payment of current taxes associated with the sale of our operations in Ecuador.

Cash provided or used by investing activities in 2003 and 2002 has been significantly impacted by our decision to reduce debt with proceeds from the sale of oil and gas properties. Investing activities in 2003 include $174.0 million for proceeds from the sales of our operations in Ecuador and certain properties in the U.S. and Canada. Investing activities in 2002 include $62.5 million of proceeds from the sales of our operations in Trinidad and our heavy oil properties in California. Capital spending was held to only $136.3 million, or 57 percent of cash provided by operating activities, in 2002 and $177.2 million, or 76 percent of cash provided by operating activities, in 2003. This provided cash to reduce debt and we have budgeted capital spending to increase again in 2004. We do not anticipate significant proceeds from property sales in 2004 and we have increased our 2004 capital budget to more closely match expected cash flows.

Cash used by financing activities in 2003 and 2002 reflects the results of our debt reduction program as we have redeemed our 9% senior subordinated notes due 2005 and our 8 5/8% senior subordinated notes due 2009 and reduced our outstanding balance under our revolving credit facility to zero at December 31, 2003. We also extended our debt maturities in 2002 by the issuance of our 8 1/4% senior notes due 2012, which reduced the balance outstanding under our revolving credit facility.

Capital Expenditures

During 2003, our total oil and gas capital expenditures were $181.8 million ($180.7 million on continuing operations). In North America, our oil and gas capital expenditures totaled $105.8 million. Exploration activities accounted for $36.1 million of our North America capital expenditures with exploitation activities contributing $61.5 million. We also spent $0.5 million on acquisitions of producing properties in the United States and $7.7 million on the acquisition of North American unproved acreage in 2003. During 2003, our international oil and gas capital expenditures outside North America totaled $76.0 million. This amount consists of exploitation activities of $58.3 million in Argentina, $1.1 million in Ecuador and $0.4 million in Bolivia and exploration activities of $12.4 million in Yemen, $1.3 million in Bolivia, $1.5 million in Bulgaria and $1.0 million in Italy.

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As of December 31, 2003, we had total unproved oil and gas property costs of approximately $58.2 million consisting of undeveloped leasehold costs of $39.2 million, including $29.7 million in Canada, and unevaluated exploratory drilling of $19.0 million. Approximately $11.8 million of the total unproved costs are associated with our drilling program in Yemen. On October 15, 2003, the Republic of Yemen s Ministry of Oil and Minerals approved our S-1 Damis block development plan for a term of 20 years. The 285,000 acre development area encompasses all of our currently capitalized costs in Yemen. As a result of this declaration of commerciality, on November 4, 2003, we were required to make a one-time payment of $1.0 million to the government of Yemen. In the second quarter of 2003, we recorded additional exploration expense of $23.7 million ($13.9 million net of tax) to fully impair our undeveloped leaseholds in the Northwest Territories. Future exploration expense and earnings may be impacted to the extent our future exploration activities are unsuccessful in discovering commercial oil and gas reserves in sufficient quantities to recover our costs.

On May 2, 2001, we completed the acquisition of Genesis for total consideration of $617 million, including transaction costs and the assumption of the net indebtedness of Genesis at closing (see Note 8 to the consolidated financial statements included elsewhere in this Form 10-K). The cash portion of the acquisition price was paid through advances under our revolving credit facility and cash on hand.

The timing of most of our capital expenditures is discretionary with no material long-term capital expenditure commitments. Consequently, we have a significant degree of flexibility to adjust the level of such expenditures as circumstances warrant. We use internally-generated cash flows to fund our capital expenditures other than significant acquisitions. Our capital expenditure budget for 2004 is currently set at $225 million, exclusive of acquisitions. We do not have a specific acquisition budget since the timing and size of acquisitions are difficult to forecast. We are actively pursuing additional acquisitions of oil and gas properties. In addition to internally-generated cash flows and advances under our revolving credit facility, we may seek additional sources of capital to fund any future significant acquisitions (see Liquidity), however, no assurance can be given that sufficient funds will be available to fund our desired acquisitions. Our recent capital expenditure history is as follows:

	Years Ended December 31,		
(In thousands)	**2003**	**2002**	**2001**
Acquisition of oil and gas reserves	$ 463	$	$ 607,217
Drilling	133,208	82,664	135,620
Acquisition of undeveloped acreage and seismic	21,537	19,592	85,489
Workovers and recompletions	22,592	24,673	62,038
Other	3,972	2,777	1,024
Oil and gas capital expenditures	181,772	129,706	891,388
Gathering system and plant projects	2,484	4,554	1,256
Total	$ 184,256	$ 134,260	$ 892,644

Capital Resources and Liquidity

Cash on hand, internally generated cash flows and the borrowing capacity under our revolving credit facility are our major sources of liquidity. We also have the ability to adjust our level of capital expenditures. We may use other sources of capital, including the issuance of additional debt securities or equity securities, to fund any major acquisitions we might secure in the future and to maintain our financial flexibility.

In the past, we have accessed the public markets to finance significant acquisitions and provide liquidity for our future activities. Since 1990, we have completed five public equity offerings as well as two public debt offerings and three Rule 144A private debt offerings, all of which have provided us with aggregate net proceeds of approximately $1.2 billion.

On May 30, 2001, we issued $200 million of our 7 7/8% Senior Subordinated Notes due 2011 (the 7 7/8% Notes). The 7 7/8% Notes are redeemable at our option, in whole or in part, at any time on or after May 15, 2006. In addition, prior to May 15, 2004, we may redeem up to 35 percent of the 7 7/8% Notes with the proceeds of certain underwritten public offerings of our common stock. The 7 7/8% Notes mature on May 15, 2011, with interest payable semi-annually on May 15 and November 15 of each year. All of our net proceeds from the sale of the 7 7/8% Notes (approximately $199.9 million) were used to repay a portion of the existing indebtedness under our revolving credit facility.

On May 2, 2002, we issued, through a Rule 144A offering, $350 million of our 8 1/4% Senior Notes due 2012 (the 8 1/4% Notes). All of the net proceeds were used to repay a portion of the outstanding balance under our revolving credit facility and to redeem $100 million of our outstanding 9% Senior Subordinated Notes due 2005 (the 9% Notes). The 8 1/4% Notes are redeemable at our option, in whole or in part, at any time on or after May 1, 2007. In addition, prior to May 1, 2005, we may redeem up to 35 percent of the 8 1/4% Notes with the proceeds of certain underwritten public offerings of our common stock. The 8 1/4% Notes mature on May 1, 2012, with interest payable semi-annually on May 1 and November 1 of each year.

In conjunction with the offering of the 8 1/4% Notes, we entered into a new $300 million revolving credit facility (as amended, the Bank Facility), which was used to refinance our previously existing credit facility and to provide funds for ongoing operating and general corporate needs. We also redeemed a portion of the 9% Notes. As a result, we were required to expense certain associated deferred financing costs and discounts. This $5.2 million non-cash charge, along with a $3.0 million cash charge for the call premium on the 9% Notes, resulted in a one-time charge of approximately $8.2 million ($5.0 million net of tax) recorded in the second quarter of 2002.

During the first quarter of 2003, we advanced funds under the Bank Facility to redeem the remainder of the 9% Notes. As a result, we were required to expense certain associated deferred financing costs and discounts. This $0.7 million non-cash charge and a $0.7 million cash charge for the call premium on the redemption of the remaining 9% Notes in 2003 resulted in a one-time charge of approximately $1.4 million ($1.0 million net of tax) recorded in the first quarter of 2003.

In October 2003, we redeemed the entire $100 million principal balance of our 8 5/8% senior subordinated notes due 2009 with cash provided by advances under the Bank Facility. As a result, we were required to expense certain associated deferred financing costs and discounts. This $2.3 million non-cash charge and a $3.2 million cash charge for the call premium resulted in a one-time charge of approximately $5.5 million ($3.4 million net of tax) in the fourth quarter of 2003.

In February 2004, we redeemed the entire $150 million principal balance of our 9 3/4% senior subordinated notes due 2009 with cash provided by advances under the Bank Facility. As a result, we were required to expense certain associated deferred financing costs. The $2.8 million non-cash charge and a $7.3 million cash charge for the call premium resulted in a one-time charge of approximately $10.1 million ($6.2 million net of tax) that we will record in the first quarter of 2004.

The Bank Facility consists of a three-year senior secured credit facility maturing in May 2005 with availability governed by a borrowing base determination. Our availability under the Bank Facility is reduced by our outstanding letters of credit. The borrowing base (currently $300 million) is based on the banks evaluation of our oil and gas reserves. The amount available to be borrowed under the Bank Facility is limited to the lesser of the borrowing base or the facility size, which is also currently set at $300 million. The next borrowing base redetermination will be in April 2004 at which time we intend to seek an extension of the Bank Facility to 2008 or beyond. The Bank Facility is secured by a first priority lien on our oil and gas properties constituting at least 80 percent of the present value of our U.S. proved reserves owned now or in the future. The Bank Facility will be guaranteed by any of our existing and future U.S. subsidiaries that grant a lien on oil and gas properties under the Bank Facility.

Outstanding advances under the Bank Facility bear interest payable quarterly at a floating rate based on Bank of Montreal s alternate base rate (as defined) or, at our option, at a fixed rate for up to six months based on the Eurodollar market rate (LIBOR). Our interest rate increments above the alternate base rate and LIBOR vary based on the level of outstanding senior debt to the borrowing base. In addition, we must pay a commitment fee of 0.50 percent per annum on the unused portion of the banks commitment. There were no outstanding advances at December 31, 2003. At February 27, 2004, we had $141.5 million outstanding under the Bank Facility, with unused availability of $157.6 million (considering outstanding letters of credit of approximately $0.9 million).

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The terms of the Bank Facility require the maintenance of a minimum current ratio (as defined therein) and a minimum tangible net worth (as defined therein). The indentures for our senior notes and our senior subordinated notes contain limitations on, among other things, additional indebtedness and liens, the payments of dividends and other distributions, certain investments and transfers or sales of assets.

The non-cash charges for impairments of our oil and gas properties that we recorded in 2003 have no material adverse impact on the financial covenants under the Bank Facility or our existing bond indentures. Our borrowing base under the Bank Facility is based primarily on our North American reserves, of which the U.S. comprised approximately 75 percent of the total volumes at December 31, 2002. We expect the adverse impact of negative reserve revisions for Canada on our borrowing base under the Bank Facility to be partially offset by the positive impact of a reduction in fixed charges resulting from our redemption of our 9 3/4% senior subordinated notes due 2009.

Our internally generated cash flows, results of operations and financing for our operations are dependent on oil and gas prices. Realized oil and gas prices for the year increased by 21 percent and 50 percent, respectively, as compared to 2002. For 2003, approximately 65 percent of our production was oil. We believe that our cash flows and unused availability under the Bank Facility are sufficient to fund our planned capital expenditures for the foreseeable future. To the extent oil and gas prices decline, our earnings and cash flows from operations may be adversely impacted. Prolonged periods of substantially lower oil and gas prices could cause us to not be in compliance with maintenance covenants under our Bank Facility and could negatively affect our credit statistics and coverage ratios and thereby affect our liquidity.

Consistent with our stated goal of maintaining financial flexibility and optimizing our portfolio of assets, we 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. We determined that the level of investment and time horizon required to continue the development of our interests in Ecuador and Trinidad were inconsistent with the timing of our desire to reduce leverage. These assets, along with our remaining heavy oil properties in the Santa Maria area of southern California, were identified for sale. Our heavy oil properties in the Santa Maria area 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. We received a cash payment as final settlement of this note in October 2002. Our interest in Trinidad was sold in July 2002 for $40 million in cash and our interest in Ecuador was sold in January 2003 for $137.4 million in cash. The closing of the sale of our interest in Ecuador, along with the sales of certain U.S. Mid-Continent gas properties and certain non-strategic oil and gas assets in Saskatchewan and West Central Alberta, Canada for a total of $57.9 million, allowed us to exceed our $200 million debt reduction goal. Our debt, less cash on hand, at December 31, 2003, was $645.1 million, compared to approximately $1.0 billion at December 31, 2001.

Off Balance Sheet Arrangements and Contractual Obligations

We have no off balance sheet arrangements, as defined by SEC rules. A summary of our contractual obligations as of December 31, 2003, is as follows (in thousands):

	Payments Due By Year						
	Total	**2004**	**2005**	**2006**	**2007**	**2008**	**Thereafter**
Long-term debt [(a)]	$ 700,000	$	$	$	$	$	$ 700,000[(b)]
Operating leases [(c)]	18,803	3,628	3,767	3,706	3,600	2,835	1,267
Firm transportation and compression agreements [(c)]	7,421	3,028	1,813	1,603	379	299	299

Argentina electric power agreement [c]	15,449	3,530	3,530	3,530	4,859		
Purchase commitments	4,425	4,425					
Yemen concession agreement [c]	6,750	338	338	338	338	338	5,060
	$ 752,848	$ 14,949	$ 9,448	$ 9,177	$ 9,176	$ 3,472	$ 706,626

(a) See Note 2 Long-term Debt to our consolidated financial statements included elsewhere in this Form 10-K.

(b) $150 million of this amount was repaid in 2004 with funds advanced under our revolving credit facility, which matures in 2005. We intend to seek an extension of the maturity of our revolving credit facility to 2008 or beyond.

(c) See Note 5 Commitments and Contingencies to our consolidated financial statements included elsewhere in this Form 10-K.

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We have no capital leases. The table on the preceding page does not include $0.9 million of letters of credit that have been issued by commercial banks on our behalf which, if funded, would become borrowings under our revolving credit facility. The $700 million of long-term debt shown in the table excludes $57,000 of discounts, which are included in the amount shown on our December 31, 2003, balance sheet.

Material contractual cash obligations for which the ultimate settlement amounts are not fixed and determinable include derivative contracts that are sensitive to future changes in commodity prices. See Item 7A. Quantitative and Qualitative Disclosure about Market Risk - Commodity Price Risk included elsewhere in this Form 10-K.

Inflation

As a result of the devaluation of the Argentine peso, 2002 peso inflation was approximately 41 percent in Argentina. However, during 2003, the Argentine inflation rate has slowed significantly, amounting to 3.7 percent for the year. In recent years inflation outside of Argentina has not had a significant impact on our operations or financial condition and is not currently expected to have a significant impact on future periods.

Income Taxes

We recorded a current provision for income taxes of $43.9 million, $21.7 million and $80.5 million for 2003, 2002 and 2001, respectively. The total provision for U.S. income taxes is based on the federal corporate statutory income tax rate plus an estimated average rate for state income taxes. Earnings of our foreign subsidiaries are subject to foreign income taxes. No U.S. deferred tax liability will be recognized related to the unremitted earnings of these foreign subsidiaries, as it is our intention, generally, to reinvest such earnings permanently. We expect that foreign income taxes will constitute a substantial portion of our overall tax burden in the foreseeable future.

We generated a U.S. federal regular income tax NOL in 2002, which we carried back against prior year taxable income, receiving a refund of taxes previously paid. We also have various state NOL carryforwards which have varying lengths of allowable carryforward periods ranging from five to 20 years and can be used to offset future state taxable income. We have a Bolivian income tax NOL carryforward of approximately $47.0 million that does not expire. Additionally, we also have a Canadian income tax NOL carryforward of approximately C$48.7 million ($37.6 million), approximately 26 percent of which will expire in 2008 with the balance expiring in 2009. We have also incurred approximately $51.3 million related to our Yemen operations that we expect to recover under the cost recovery provisions of our production sharing agreement with the government of Yemen. These provisions allow us to annually offset a portion of our revenues that would otherwise be taxable with costs we previously incurred in Yemen until such costs have been fully recovered. We expect to recover this amount over the next five years.

As a result of the impairment to our book value for our Canadian oil and gas properties due to the significant reduction in our Canadian reserves and estimated future net revenues associated with these reserves, our tax basis in our Canadian properties exceeded our book basis at December 31, 2003. This excess tax basis, along with the Canadian income tax NOL, resulted in a net deferred tax asset for Canada at December 31, 2003. We evaluated the likelihood of the recoverability of this Canadian deferred tax asset based on current projections of future taxable income and determined this likelihood to be remote. Therefore, we have placed a valuation allowance against our entire Canadian deferred tax asset of $35.7 million. This valuation allowance will be evaluated in the future to determine if changes in facts and circumstances warrant a change to the valuation allowance.

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Changes in our income tax expense (benefit) are a function of our consolidated effective tax rate and our pre-tax income (loss). The increase in our income tax benefit for 2003 as compared to 2002 is primarily due to the significantly higher loss recorded by our Canadian operating subsidiary in 2003 as a result of the impairments to producing oil and gas properties recorded in the second, third and fourth quarters and the higher exploration expense resulting from the impairment of our Northwest Territories unproved acreage in the second quarter. This tax benefit was partially offset by a higher effective tax rate on our Argentine income due to the impact of the strengthening of the Argentine peso. Additionally, we recorded a valuation allowance on our Canadian deferred tax asset at the end of 2003, reducing the tax benefit of the net loss. As a result of the valuation allowance, we do not expect to tax effect any future earnings or losses from our Canadian operating subsidiary. This position could change should facts and circumstances differ from our current expectations. Our overall effective tax rate on continuing operations was 21.6 percent and 27.1 percent for 2003 and 2002, respectively.

We recorded an income tax benefit of $39.1 million in 2002 compared to income tax expense of $68.3 million in 2001. The difference between 2002 and 2001 is primarily due to the significant loss recorded by our Canadian operating subsidiary in 2002 as a result of the impairment to producing oil and gas properties recorded in the fourth quarter. Because our effective tax rate in Canada was higher than the U.S. statutory rate and because of our net loss position in Canada, our overall effective tax rate was lower. Also, as a result of the devaluation of the Argentine peso in 2002, our effective tax rate in Argentina was lower than the 35 percent statutory rate, further reducing our overall effective tax rate. Our overall effective tax rate on continuing operations was 27.1 percent and 35.1 percent for 2002 and 2001, respectively.

As part of our results from discontinued operations for 2003, we recorded additional U.S. income taxes of $37.7 million related to the repatriation of previously untaxed foreign earnings as a result of the sale of our Ecuador subsidiary in January 2003, bringing the 2003 effective tax rate on discontinued operations to 77.9 percent, compared to 46.5 percent for 2002, which primarily related to the sale of our Trinidad subsidiary.

Critical Accounting Policies and Estimates

Management s discussion and analysis of our financial condition and results of operations are based on our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States (GAAP). GAAP represents a comprehensive set of accounting and disclosure rules and requirements, the application of which requires management judgments and estimates including, in certain circumstances, choices between acceptable GAAP alternatives. The preparation of these consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from these estimates under different assumptions or conditions. Note 1 to our consolidated financial statements included elsewhere in this Form 10-K, contains a comprehensive summary of our significant accounting policies. The following is a discussion of our most critical accounting policies, judgments and uncertainties that are inherent in our application of GAAP:

Accounting for Oil and Gas Properties. Under the successful efforts method of accounting, we capitalize all costs related to property acquisitions and successful exploratory wells, all development costs and the costs of support equipment and facilities. Certain costs of exploratory wells are capitalized pending determination that proved reserves have been found. Such determination is dependent upon the results of planned additional wells and the cost of required capital expenditures to produce the reserves found. All costs related to unsuccessful exploratory wells are expensed when such wells are determined to be non-productive; other exploration costs, including geological and geophysical costs, are expensed as incurred. We recognize gains or losses on the sale of properties on a field basis.

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The application of the successful efforts method of accounting requires management s judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. Wells may be completed that are assumed to be productive and actually deliver oil and gas in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Delineation seismic costs incurred to select development locations within a productive oil and gas field are typically treated as development costs and capitalized. Judgment is required to determine when the seismic programs are not within proved reserve areas and therefore would be charged to expense as exploratory. The evaluation of oil and gas leasehold acquisition costs requires management s judgment to estimate the fair value of exploratory costs related to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

The successful efforts method of accounting can have a significant impact on the operational results reported when we enter a new exploratory area in hopes of finding oil and gas reserves. Seismic costs can be substantial which will result in additional exploration expenses when incurred. The initial exploratory wells may be unsuccessful and the associated costs will then be expensed as dry hole costs and any associated leasehold costs may be impaired.

Proved reserve estimates. Estimates of our proved reserves included in our consolidated financial statements and elsewhere in this Form 10-K are prepared in accordance with guidelines established by GAAP and by the SEC. 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. The accuracy of a reserve estimate is a function of: (i) the quality and quantity of available data; (ii) the interpretation of that data; (iii) the accuracy of various mandated economic assumptions; and (iv) the judgment of the persons preparing the estimate.

Our proved reserve information is based on estimates prepared by our independent petroleum consultants. Estimates prepared by others may be higher or lower than these estimates. Because these estimates depend on many assumptions, all of which may substantially differ from actual results, reserve estimates may be different from the quantities of oil and gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate.

The present value of future net cash flows should not be assumed to be the current market value of our estimated proved reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves were based on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate.

The estimates of proved reserves materially impact depletion, depreciation and amortization expense. If the estimates of proved reserves decline, the rate at which we record depletion, depreciation and amortization expense increases, reducing net income. Such a decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost reserves or from volume revisions resulting from actual production rates, drilling results in nearby areas or other factors. In addition, the decline in proved reserve estimates may impact the outcome of our assessment of our oil and gas producing properties and goodwill for impairment.

Impairment of proved oil and gas properties. We review our proved oil and gas properties for impairment on a field basis. For each field, an impairment provision is recorded whenever events or circumstances indicate that the carrying value of those properties may not be recoverable. The impairment provision is based on the excess of carrying value over fair value. Fair value is defined as the present value of the estimated future net revenues from production of total proved and risk-adjusted probable and possible oil and gas reserves over the economic life of the reserves, based on our expectations of future oil and gas prices and costs, consistent with methods used for acquisition evaluations. Oil and gas reserve estimates may change in future periods and oil and gas prices are historically volatile. Events may arise that will require us to record an impairment of our oil and gas properties and there can be no assurance that such impairments will not be required in the future.

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Impairment of unproved oil and gas properties. Unproved leasehold costs and exploratory drilling in progress are capitalized and are reviewed periodically for impairment. Costs related to impaired prospects or unsuccessful exploratory drilling are charged to expense. Our assessment of the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such leaseholds impacts the amount and timing of impairment provisions. An impairment expense could result if oil and gas prices decline in the future as it may not be economic to develop some of these unproved properties. As of December 31, 2003, we had total unproved oil and gas property costs of approximately $58.2 million consisting of undeveloped leasehold costs of $39.2 million, including $29.7 million in Canada, and unevaluated exploratory drilling costs of $19.0 million. Approximately $11.8 million of the total unevaluated costs are associated with our drilling program in Yemen.

Impairment of goodwill. Through December 31, 2003, we were required to assess our goodwill for impairment at least annually. We performed an initial assessment of whether there was an indication that the carrying value of goodwill was impaired. This assessment was made by comparing the fair value of our Canadian operations, as determined in accordance with SFAS 142, to the book value. If the fair value was less than the book value, an impairment was indicated and we performed a second test to measure the amount of the impairment. In the second test, we then calculated the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of our Canadian operations from the fair value of our Canadian operations determined in step one of the assessment. If the carrying value of the goodwill exceeded this calculated implied fair value of the goodwill, an impairment charge was recorded. As a result of a $25.7 million impairment recorded in 2003, we had no remaining goodwill recorded at December 31, 2003.

Estimates of future dismantlement, restoration, and abandonment costs. Through December 31, 2002, we had accrued future abandonment costs of wells and related facilities through our depreciation calculation in accordance with the provisions of SFAS 19 and industry practice. The accounting for future development and abandonment costs changed on January 1, 2003, with the adoption of SFAS 143. See New Accounting Pronouncements in Note 1 to our consolidated financial statements included elsewhere in this Form 10-K for a further discussion of this new standard. Under both methods of accounting, the accrual is based on estimates of these costs for each of our properties based upon the type of production structure, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make estimates and judgments that are subject to future revisions based on numerous factors, including changing technology, the political and regulatory environment and, beginning in 2003, estimates as to the proper discount rate to use and timing of abandonment.

Accounting for Derivative Financial Instruments. We periodically use derivative financial instruments as hedges to reduce the impact of oil and natural gas price fluctuations. We account for our hedging activities under the provisions of Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (as amended, SFAS 133), which requires us to record the fair value of our derivative financial instruments as either an asset or liability on our balance sheet. We utilize market-based quotes from our counterparties to value our open positions. Future market price volatility for oil and gas could result in significant changes to the amounts recorded on our balance sheet.

To the extent that the derivative financial instruments qualify as effective cash flow hedges, we record any gains or losses on the open position in other comprehensive income. We record the results of settled oil or gas hedges as an adjustment to oil and gas sales in the period that the hedged forecasted transaction is recorded. If a derivative financial instrument does not qualify as an effective hedge, we record all changes in its fair value currently in our results of operations.

We must formally designate each cash flow hedge as such at its inception, documenting the nature of the risk being hedged, the specific hedged item and its volume, the hedging instrument and our basis for selecting that instrument, and the methodology we will use to determine the hedge s effectiveness or ineffectiveness. Both at its inception and on an ongoing basis, we must use judgment to assess whether the hedging instrument is highly effective in offsetting the changes in cash flows of the hedged transaction.

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SFAS 133 also requires us to continually assess whether occurrence of the forecasted transaction is probable. If we determine that the forecasted transaction in a hedge is no longer probable, we must discontinue hedge accounting for that derivative financial instrument, reclassify any amounts in other comprehensive income into our results of operations and record any changes in that instrument s fair value in our results of operations from that point forward.

Income taxes. We provide deferred income taxes on transactions which are recognized in different periods for financial and tax reporting purposes. We have not recognized a U.S. deferred tax liability related to the unremitted earnings of any of our foreign subsidiaries as it is our intention, generally, to reinvest such earnings permanently. Management periodically assesses the need to utilize these unremitted earnings to finance our operations. This assessment is based on cash flow projections that are the result of estimates of future production, commodity pricing and expenditures by tax jurisdiction for our operations. Such estimates are inherently imprecise since many assumptions utilized in the cash flow projections are subject to revision in the future.

We have also recorded deferred tax assets related to operating loss and tax credit carryforwards. We periodically assess the probability of recovery of recorded deferred tax assets based on our assessment of future earnings outlooks by tax jurisdiction and record valuation allowances when this assessment results in a determination that recoverability is not likely. Such estimates and determinations are inherently imprecise because many assumptions are utilized in the assessments that may prove to be incorrect in the future.

Assessments of functional currencies. All of our subsidiaries use the U.S. dollar as their functional currency, except for our Canadian operating subsidiary, which uses the Canadian dollar. Management determines the functional currencies of our subsidiaries based on an assessment of the currency of the economic environment in which a subsidiary primarily realizes and expends its operating revenues, costs and expenses. The assessment of functional currencies can have a significant impact on periodic results of operations and financial position.

Argentina economic and currency measures. The accounting for and translation of the financial statements of our operations in Argentina reflect management s assumptions regarding uncertainties unique to Argentina s current economic situation. See Note 1 to our consolidated financial statements included elsewhere in this Form 10-K, for a description of the assumptions utilized in the preparation of these consolidated financial statements. Argentina s economic and political situation evolves continuously and the Argentine government has adopted numerous decrees, is considering implementing various alternatives and may enact future regulations or policies that may materially impact, among other items, (i) the realized prices we receive for oil and gas we produce and sell; (ii) the timing and amount of repatriations of cash to the U.S.; (iii) the amount of permitted export sales; (iv) the Argentine banking system; (v) our asset valuations; and (vi) peso-denominated monetary assets and liabilities. For further information, see Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Foreign Currency and Operations Risk included elsewhere in this Form 10-K.

Changes in Accounting Principles

In June 1998, the Financial Accounting Standards Board (the FASB) issued SFAS 133. SFAS 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS 133 requires that changes in the derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative s gains and losses to offset related results on the hedged item in the statement of operations. Companies must formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

Upon adoption of SFAS 133 on January 1, 2001, we recorded a transition receivable of $18.5 million related to cash flow hedges in place that are used to reduce the volatility in commodity prices for portions of our forecasted oil production. Additionally, we recorded, net of tax, an increase to accumulated other comprehensive income in the Stockholders Equity section of the balance sheet of approximately $14.9 million. The amount recorded to accumulated other comprehensive income was taken to the statement of operations as the physical transactions being hedged were finalized. All of our cash flow hedges in place at January 1, 2001, had settled as of December 31, 2001, with the actual cash flow impact recorded in oil and gas sales in our statement of operations.

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On July 20, 2001, the FASB issued Statement of Financial Accounting Standards No. 141, *Business Combinations* (SFAS 141), and SFAS 142. SFAS 141 requires all business combinations initiated after June 30, 2001, to be accounted for using the purchase method of accounting. Under SFAS 142, goodwill is no longer subject to amortization. Rather, goodwill will be subject to at least an annual assessment for impairment by applying a fair-value based test. Additionally, an acquired intangible asset should be separately recognized if the benefit of the intangible asset is obtained through contractual or other legal rights, or if the intangible asset can be sold, transferred, licensed, rented or exchanged, regardless of the acquirer s intent to do so.

We adopted SFAS 141 and SFAS 142 effective January 1, 2002, resulting in the elimination of goodwill amortization from statements of operations in future periods. As discussed in Note 4 to our consolidated financial statements included elsewhere in this Form 10-K, we recorded an impairment charge of $60.5 million related to the goodwill of our Canadian operations as a cumulative effect of a change in accounting principle in our statement of operations.

On January 1, 2002, we adopted the provisions of SFAS 144. SFAS 144 creates accounting and reporting standards to establish a single accounting model, based on the framework established in Statement of Financial Accounting Standards No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of*, for long-lived assets to be disposed of by sale. The adoption of SFAS 144 did not have a material impact on our financial position or results of operations.

On April 30, 2002, the FASB issued Statement of Financial Accounting Standards No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections* (SFAS 145). SFAS 145 updates, clarifies and simplifies existing accounting pronouncements. Among other items, it rescinds previous accounting rules which required all gains and losses from extinguishment of debt to be aggregated and, if material, classified as an extraordinary item, net of related income tax effect. We have adopted the provisions of SFAS 145 and, accordingly, have classified losses on the early extinguishment of debt of $6.9 million ($4.2 million net of tax) in 2003 and $8.2 million ($5.0 million net of tax) in 2002 (see Note 2 to our consolidated financial statements included elsewhere in this Form 10-K) as charges to income from continuing operations in our statements of operations. The adoption of SFAS 145 did not have any other material impact on our financial position or results of operations.

In August 2001, the FASB issued SFAS 143. We were required to adopt this new standard beginning January 1, 2003. Through December 31, 2002, we accrued future abandonment costs of wells and related facilities through our depreciation calculation and included the cumulative accrual in accumulated depreciation in accordance with the provisions of SFAS 19 and industry practice. At December 31, 2002, approximately $54.6 million of accrued future abandonment costs were included in our accumulated depreciation. The new standard requires that we record the discounted fair value of the retirement obligation as a liability at the time a well is drilled or acquired. The asset retirement obligations consist primarily of costs associated with the plugging and abandonment of oil and gas wells, site reclamation and facilities dismantlement. However, future abandonment liabilities are also recorded for other assets such as pipelines, processing plants and compressors. A corresponding amount is capitalized as part of the related property s carrying amount. The discounted capitalized asset retirement cost is amortized to expense through the depreciation calculation over the estimated useful life of the asset based on proved reserves. The liability accretes over time with a charge to accretion expense. At January 1, 2003 there were no assets legally restricted for purposes of settling asset retirement obligations. We adopted the new standard effective January 1, 2003, and recorded an increase in property, plant and equipment of approximately $50.3 million, a decrease in accumulated depreciation, depletion and amortization of approximately $43.9 million, an increase in current asset retirement liabilities of approximately $4.5 million, an increase in long-term asset retirement liabilities of approximately $78.5 million, a $4.1 million increase in deferred income tax liabilities and a gain as a result of the cumulative effect of change in accounting principle, net of tax, of approximately $7.1 million.

On July 30, 2002, the FASB issued Statement of Financial Accounting Standards No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. The standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. The provisions of this statement are to be applied prospectively to exit or disposal activities initiated after December 31, 2002. The adoption of this standard had no impact on our financial position or results of operations.

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On December 31, 2002, the FASB issued Statement of Financial Accounting Standards No. 148, *Accounting for Stock-Based Compensation - Transition and Disclosure* (SFAS 148). SFAS 148 amends Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation* (SFAS 123), to provide alternative methods of transition to SFAS 123 s fair value method of accounting for stock-based employee compensation. SFAS 148 also amends the disclosure provisions of SFAS 123 and APB Opinion No. 28, *Interim Financial Reporting*, to require disclosure in the summary of significant accounting policies of the effects of an entity s accounting policy with respect to stock-based employee compensation on reported net income and earnings per share in annual and interim financial statements. We adopted the disclosure provision of SFAS 148 in our consolidated financial statements included elsewhere in this Form 10-K as of December 31, 2002. Effective January 1, 2003, we adopted the fair value recognition provisions of SFAS 123. We adopted these provisions prospectively to all employee and director awards granted, modified or settled after January 1, 2003. The impact of adopting this standard was not significant to our results of operations.

In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51* and revised this interpretation in December 2003 (FIN 46). FIN 46 requires the consolidation of variable interest entities by their primary beneficiary if the variable interest entities do not effectively disperse risks among the parties involved. Previously, entities were generally consolidated by an enterprise when it had a controlling financial interest through ownership of a majority of voting interest in the entity. The adoption of FIN 46 had no impact on our financial position or results of operations.

On April 30, 2003, the FASB issued Statement of Financial Accounting Standards No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* (SFAS 149). SFAS 149 is intended to result in more consistent reporting of contracts as either freestanding derivative instruments subject to SFAS 133 in its entirety, or as hybrid instruments with debt host contracts and embedded derivative features. SFAS 149 was effective for contracts entered into or modified after June 30, 2003, and hedging relationships designated after June 30, 2003. The adoption of SFAS 149 had no impact on our financial position or results of operations.

On May 15, 2003, the FASB issued Statement of Financial Accounting Standards No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* (SFAS 150). SFAS 150 establishes standards for classifying and measuring as liabilities certain financial instruments that embody obligations of the issuer and have characteristics of both liabilities and equity. SFAS 150 must be applied immediately to instruments entered into or modified after May 31, 2003, and to all other instruments that exist as of the beginning of the first interim financial reporting period beginning after June 15, 2003. Early adoption of SFAS 150 is not permitted. The adoption of SFAS 150 had no impact on our financial position or results of operations.

Foreign Operations

For information on our foreign operations, see Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Foreign Currency and Operations Risk included elsewhere in this Form 10-K.

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

Our operations are exposed to market risks primarily as a result of changes in commodity prices, interest rates and foreign currency exchange rates. We do not use derivative financial instruments for speculative or trading purposes.

Commodity Price Risk

We produce, purchase and sell crude oil, natural gas, condensate, natural gas liquids and sulfur. As a result, our financial results can be significantly impacted as these commodity prices fluctuate widely in response to changing market forces. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations - Future Period Hedges for a discussion of the impact of commodity price changes based on 2003 production levels. We have previously engaged in oil and gas hedging activities and we intend to continue to consider various hedging arrangements to realize commodity prices which we consider favorable.

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During 2001, we entered into oil hedging contracts for various periods in 2001 covering 1.9 MMBbls of oil at a weighted average NYMEX reference price of $29.28 per Bbl. Including hedges entered into in 2000, we entered into total oil hedging contracts covering 2001 production of 5.5 MMBbls of oil at a weighted average NYMEX reference price of $30.20 per Bbl. During 2001, we entered into various oil hedges (swap agreements) for a total of 0.9 MMBbls of oil at a weighted average NYMEX reference price of $25.54 per Bbl for various periods in 2002. At December 31, 2001, we would have received approximately $4.7 million to terminate our oil swap agreements then in place.

During 2002, we entered into additional oil hedging contracts for various periods in 2002 covering an additional 4.0 MMBbls of oil at a weighted average NYMEX reference price of $25.08 per Bbl. In total, we entered into oil hedging contracts covering 2002 production of 4.9 MMBbls of oil at a weighted average NYMEX reference price of $25.16 per Bbl. Also during 2002, we entered into various gas price swap agreements covering approximately 11.3 million MMBtu of our gas production for 2002. The U.S. portion of the gas swap agreements (approximately 5.2 million MMBtu) was at a NYMEX reference price of $2.72 per MMBtu. The Canadian portion of the gas price swap agreements (approximately 6.1 million MMBtu) was at the AECO gas price index reference price of 3.67 Canadian dollars per MMBtu and was settled in Canadian dollars. Additionally, we entered into costless price collar arrangements for approximately 2.2 million MMBtu of our U.S. gas production in 2002. The price collars had a floor NYMEX reference price of $3.50 per MMBtu and cap NYMEX reference prices of $4.00 to $5.10 per MMBtu. In conjunction with each of the 2002 U.S. gas price swaps and costless price collars, we entered into basis swap agreements covering identical periods of time and volumes. These basis swaps established a differential between the NYMEX reference price and the various delivery points at levels that are comparable to the historical differentials we received.

During 2002, we entered into various oil hedges (swap agreements) for a total of 3.0 MMBbls of oil at a weighted average NYMEX reference price of $24.90 per Bbl for various periods in 2003. During 2002, we also entered into various gas hedges (swap agreements) covering approximately 20.1 million MMBtu of our 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) was at a weighted average NYMEX reference price of 6.63 Canadian dollars per MMBtu and was settled in Canadian dollars. The U.S. portion of the gas swap agreements (approximately 11 million MMBtu) was at a weighted average NYMEX reference price of $4.00 per MMBtu. Additionally, we entered into basis swap agreements for approximately 8.4 million MMBtu of our U.S. gas production covered by the gas swap agreements. These basis swaps established a differential between the NYMEX reference price and the various delivery points at levels that were comparable to the historical differentials we received. At December 31, 2002, we would have paid approximately $17.1 million to terminate our swap agreements then in place.

During 2003, we entered into additional oil hedging contracts for various periods of 2003 covering an additional 1.9 MMBbls of oil at a weighted average NYMEX reference price of $30.11 per Bbl. In total, we entered into oil hedging contracts covering 2003 production of 4.9 MMBbls at a weighted average NYMEX reference price of $26.93 per Bbl.

During 2003, we entered into oil hedging contracts for various periods of 2004 covering 3.6 MMBbls of oil at a weighted average NYMEX reference price of $29.33 per Bbl and for various periods of 2005 covering 1.4 MMBbls of oil at a weighted average NYMEX reference price of $25.73 per Bbl. At December 31, 2003, we would have paid approximately $7.9 million to terminate our swap agreements then in place.

During 2004, we entered into additional oil hedging contracts for various periods of 2004 covering an additional 1.7 MMBbls of oil at a weighted average NYMEX reference price of $30.05 per Bbl. In total, we have entered into oil hedging contracts covering 2004 production of 5.3 MMBbls at a weighted average NYMEX reference price of $29.56.

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

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

The counterparties to our current hedging agreements are commercial or investment banks. We continue to monitor oil and gas prices and we may enter into additional oil and gas hedges or swaps in the future.

Interest Rate Risk

Our interest rate risk exposure results primarily from short-term rates, mainly LIBOR-based on borrowings from our commercial banks. To reduce the impact of fluctuations in interest rates, we have historically maintained a portion of our total debt portfolio in fixed-rate debt. At December 31, 2003, all of our outstanding debt was at fixed rates. However, we expect that this relationship will not continue and that a portion of our debt in future periods will be at variable rates. In February 2004, we redeemed a portion of our fixed-rate debt with funds advanced under our revolving credit facility. In the past, we have not entered into financial instruments such as interest rate swaps or interest rate lock agreements. However, we may consider these instruments to manage our portfolio mix between fixed and floating rate debt and to mitigate the impact of changes in interest rates based on our assessment of future interest rates, volatility of the yield curve and our ability to access the capital markets in a timely manner.

Because we had no outstanding borrowings under variable-rate debt instruments as of December 31, 2003, a change in the average interest rate of 100 basis points would result in no change in our net income (loss) and cash flows before income taxes.

The following table provides information about our long-term debt, principal payments and weighted-average interest rates by expected maturity dates as of December 31, 2003:

	2004	2005	2006	2007	2008	There - after	Total	Fair Value at

			12/31/03
Long-term Debt:			
Fixed-rate (in thousands)	$ 700,000 (a)	$ 700,000 (a)	$ 749,500
Average interest rate	8.5%	8.5%	
Variable-rate (in thousands)			
Average interest rate			

(a) $150 million of this amount was repaid in 2004 with funds advanced under our revolving credit facility, which matures in 2005. We intend to seek an extension of the maturity of our revolving credit facility to 2008 or beyond.

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Foreign Currency and Operations Risk

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

Historically, we have not used derivatives or other financial instruments to hedge the risk associated with the movement in foreign currencies. However, we evaluate currency fluctuations and we will consider the use of derivative financial instruments or employment of other investment alternatives if we believe cash flows or investment returns so warrant.

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

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

We do not currently maintain political risk insurance. However, we will consider obtaining such coverage in the future if we deem conditions so warrant.

Canada. We view the operating environment in Canada as stable and the economic stability as good. Substantially all of our Canadian revenues and costs are denominated in Canadian dollars. While the value of the Canadian dollar does fluctuate in relation to U.S. dollar, we believe that any currency risk associated with our Canadian operations would not have a material impact on our results of operations. The exchange rate at December 31, 2003, was US$1:C$1.30 as compared to US$1:C$1.58 at December 31, 2002.

Argentina. Beginning in 1991, Peronist Carlos Menem, as newly-elected President of Argentina, and Domingo Cavallo, as Minister of Economy, set out to reverse economic decline through free market reforms such as open trade. The key to their plan was the Law of Convertibility under which the peso was tied to the U.S. dollar at a rate of one peso to one U.S. dollar. Between 1991 and 1997 the plan succeeded. With the risk of devaluation apparently removed, capital came in from abroad and much of Argentina s state-owned assets were privatized. During this period, the economy grew at an annual average rate of 6.1 percent, the highest in the region.

However, the convertibility plan left Argentina with few monetary policy tools to respond to outside events. A series of external shocks began in 1998: prices for Argentina s commodities stopped rising; the dollar appreciated against other currencies; and Brazil, Argentina s main trading partner, devalued its currency. Argentina began a period of economic deflation, but failed to respond by reforming government spending. During 2001, Argentina s budget deficit exceeded $9 billion and its sovereign debt reached $140 billion.

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As a result of economic instability and substantial withdrawals from the banking system, in early December 2001, the Argentine government, with Fernando de la Rua as President and Domingo Cavallo as Minister of Economy, instituted restrictions that prohibit certain foreign money transfers without Central Bank approval and limit cash withdrawals from bank accounts for personal transactions in small amounts with certain limited exceptions. While the legal exchange rate remained at one peso to one U.S. dollar, financial institutions were allowed to conduct only limited activity due to these controls, and currency exchange activity was effectively halted except for personal transactions in small amounts.

In late December 2001, as a result of political riots and upheaval in response to the banking restrictions, Fernando de la Rua was removed as president and the government was left in the hands of the Peronist controlled congress. Peronist Adolfo Rodriguez Saa, governor of San Luis province was named as the transitional president and held power for one week. During this time, he announced default on Argentina s $140 billion sovereign debt.

In early January 2002, congress conferred power to Peronist Eduardo Duhalde, who enacted temporary measures intended to achieve economic stability and avoid default on multilateral debts. In addition, President Duhalde set in motion a plan to transition the government back into the hands of an elected president on May 25, 2003, approximately six months ahead of the congressional mandate.

On January 6, 2002, the Argentine government abolished the one peso to one U.S. dollar legal exchange rate. On January 9, 2002, Decree 71 created a dual exchange market whereby foreign trade transactions were conducted at an official exchange rate of 1.4 pesos to one U.S. dollar and other transactions were conducted in a free floating exchange market. On February 8, 2002, Decree 260 unified the dual exchange markets and allowed the peso to float freely with the U.S. dollar. The exchange rate at December 31, 2003, was 2.94 pesos to one U.S. dollar. The devaluation of the peso reduced our gas revenues and peso-denominated costs. Our oil revenues remain valued on a U.S. dollar basis.

Monetary assets and liabilities denominated in pesos at December 31, 2003, were as follows (in thousands):

	Peso Balance	U.S. Dollar Equivalent
Current assets	16,705	$ 5,692
Current liabilities	(84,127)	(28,664)
Non-current liabilities	(104,151)	(35,486)
Net liabilities	(171,573)	$ (58,458)

On February 3, 2002, Decree 214 required all contracts that were previously payable in U.S. dollars to be payable in pesos. Pursuant to an emergency law passed on January 10, 2002, U.S. dollar obligations between private parties due after January 6, 2002, were liquidated in pesos at a negotiated rate of exchange which reflected a sharing of the impact of the devaluation. Our settlements in pesos of the existing U.S. dollar-denominated agreements were completed in 2002 and future periods will not be impacted by this mandate.

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 maximum of five years. The tax of 20 percent is applied on the sales value after the tax, thus the net effect is 16.7 percent. During 2003, we exported approximately 60 percent of our Argentine oil production. We believe that this export tax has and will continue to have the effect of decreasing all future Argentine oil revenues (not only export revenues) by as much as the tax rate for the duration of the tax. The U.S. dollar equivalent value for domestic Argentine oil sales (now paid in pesos) has generally moved toward parity with the U.S. dollar-denominated export values, net of the export tax. The adverse impact of this tax has been partially offset by the net cost savings resulting from the devaluation of the peso on peso-denominated costs and is further reduced by the Argentine income tax savings related to deducting the impact of the export tax. The export tax is not deducted in the calculation of royalty payments. We are required by law to repatriate to Argentina 30 percent of the export sales proceeds received in the U.S. This requirement places no significant limitations on us because this provides us the pesos we need to fund our operating expenses and capital expenditures in Argentina.

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Since May 2002, many of Argentina s important economic indicators have stabilized. The Central Bank s foreign currency reserves have risen from a low of $8.9 billion in 2002 to a recent high on February 26, 2004, of $15 billion. Since being allowed to freely float against the U.S. dollar, the peso reached its weakest value at 3.80 pesos to one U.S. dollar in June of 2002, and has since stabilized, gradually appreciating to a value of 2.92 pesos to one U.S. dollar on February 27, 2004. Monthly inflation has decreased from a high of 10 percent for the month of April 2002 to an average of less than two percent per month from May to December 2002 with annual inflation during 2003 of 3.66 percent. Inflation for all of 2002 was approximately 41 percent.

After a year of negotiations, on January 24, 2003, the International Monetary Fund (the IMF) executed a transitional $6.8 billion, eight-month Stand-By Credit Arrangement to provide financial stability through the presidential elections. After a successful transition of government, and as a result of restoring a measure of economic stability and growth during 2002, in September 2003, the IMF approved a $13.5 billion Stand-By Credit Arrangement, to be disbursed in stages over a three-year period, to succeed the transitional arrangement that expired on August 31, 2003. The economic program to which the Argentine government and the IMF agreed is based on a fiscal framework to meet growth, employment, and social objectives, while providing a basis for normalizing relations with creditors and ensuring debt sustainability, a strategy to assure strengthening of the banking system and facilitating an increase in bank lending, and further institutional and tax reforms to facilitate corporate debt restructuring and fundamentally improving the investment climate. On January 28, 2004, the IMF completed and approved its first review of Argentina s performance under the three-year program. The second review is expected to conclude during March 2004.

On January 2, 2003, at the Argentine government s request, crude oil producers and refiners agreed to limit amounts payable for domestic sales occurring during the first quarter of 2003 to a maximum $28.50 per Bbl. The producers and refiners further agreed that the difference between the actual price and the maximum price would be payable once actual prices fell below the maximum. 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 maximum 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 maximum 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. This agreement has been extended to February 29, 2004. We believe that it will be further extended to April 30, 2004, during the coming weeks.

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

The plan set in motion by President Duhalde to transition the government back into the hands of an elected president was successfully completed during May 2003. General elections were held on April 27, 2003, and a runoff election between the top two candidates, former president Carlos Menem and the then current governor of Santa Cruz province, Nestor Kirchner were scheduled for May 18, 2003. Mr. Menem withdrew from the race and as a result, the runoff election was cancelled and Nestor Kirchner became president on May 25, 2003. President Kirchner has achieved a high approval rating thus far among the Argentine electorate and has achieved success with his efforts to reform the supreme court, to receive continued backing from the IMF, and to build a stronger and more inclusive political base.

Bolivia. Since the mid-1980 s, Bolivia has undergone major economic reform, including the establishment of a free market economy and the encouragement of foreign private investment. Economic activities that had once been reserved for government corporations were opened to private investments. Barriers to international trade have been reduced and tariffs have been lowered. A new investment law and associated regulations have been introduced for the mining and petroleum industries, intended to attract foreign investment.

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Elections held during June 2002 marked the sixth consecutive democratic election in Bolivia since 1982, representing the longest period of constitutional democratic government in the country s history. Coalitions were formed among the two leading political parties allowing former President Gonzalo Sanchez de Lozada to win the runoff election. However, President Sanchez de Lozada failed to gain political support and consensus for his new administration. In early 2003, in an effort to control the budget, President de Lozada proposed tax increases and cuts in government spending, which were met with violent protests. After revising his 2003 budget plans and reorganizing his cabinet, the protests ended and President de Lozada was able to negotiate terms with the IMF for a one year stand-by loan agreement for $118 million, which occurred in April 2003.

In August 2003, in an effort to reestablish political support in congress, President de Lozada accepted the resignation of his entire cabinet and named new ministers, including members of his rival political party. In September 2003, peasants, miners, coca farmers and labor unions held marches and demonstrations protesting the government s proposal to export gas to the U.S. and Mexico, and demanded the resignation of President de Lozada. After the protests turned violent and after the further loss of political support, President de Lozada was forced to resign on October 17, 2003. In accordance with the Bolivian constitution, the Vice President, Carlos Mesa, was named president.

President Mesa is an ex-journalist and is considered an independent with no affiliation to the major political parties in Bolivia. Furthermore, he has named independents to his new cabinet in an effort to break political deadlock. Since taking office, President Mesa has demonstrated the ability to create consensus between the diverse groups within Congress. President Mesa recently obtained congressional support clearing the way for a decree referred to as the Law of Constitutional Reforms, which will establish a Constituent Assembly with broad representation who will be charged with forming a new Bolivian constitution by 2006. President Mesa s restructuring efforts have received financial support from the World Bank, which has announced it will loan Bolivia $300 million over the next two years.

President Mesa has promised to call for a referendum to vote on plans to export Bolivian gas to North America, which is expected to take place by mid-2004 after presentation to the Bolivian Congress of a revised hydrocarbons law. The government has stated its intention to revise the hydrocarbons law, in part, to increase taxation of the energy industry by as much as $50 million per year.

In 1987, the Boliviano replaced the peso and became Bolivia s currency. The exchange rate is set daily by the government s exchange house, the Bolsin, which is under the supervision of the Bolivian Central Bank. Foreign exchange transactions are not subject to any controls. The exchange rate at December 31, 2003, was 7.84 Bolivianos to one U.S. dollar. Since our gas revenues are received in U.S. dollars, we believe that any currency risk associated with our Bolivian operations would not have a material impact on our financial position or results of operations.

The market for gas sales in Bolivia is currently limited to exports to Brazil via the Bolivia to Brazil gas pipeline and those internal gas sales necessary to meet Bolivian industrial and consumer demand. We are working to increase sales in both of these areas and currently have capacity to deliver gas volumes substantially in excess of our contracted volumes. During the past several years, Bolivian gas reserve growth has exceeded the demand growth in Bolivia s existing markets. Therefore, we believe substantial competition for gas markets will continue at least until new market areas are established. With President Mesa s promise of public referendum on the matter of gas exports, we believe that new projects, such as exports to Mexico, Argentina and the U.S., will become feasible in the future.

Yemen. Yemen has been classified as a low-income developing country by the World Bank. Trade and other external economic links have been limited, with the exception of the oil sector, which accounts for more than 25 percent of Yemen s gross domestic product. The production sharing agreements under which private investors operate are clear and unambiguous, resulting in most of the country s foreign investment being concentrated in the oil sector. The government has relaxed the broader regulatory environment to encourage additional foreign investments. However, obstacles such as an insufficient infrastructure, continue to exist. Necessary economic reforms began during 1995 and were supported by both the IMF and the World Bank. The reforms were targeted to enable a more market-based and private sector driven economy and more integration into world markets, all within the context of broad financial and macro-economic stability. These reforms continue to influence Yemen s economic policies today.

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Yemen has taken significant steps to stabilize its political environment since the end of its civil war in 1994. The government is dominated by northern Yemen, located in the capital city of Sana a and headed by President Ali Abdullah Saleh, who is a member of the General People s Congress. The General People s Congress has held power since the mid-1990 s and regime change is considered to be unlikely. Civil society is relatively weak and tribal structures remain powerful. Concerns about terrorism and kidnappings are ongoing security risks. We have evaluated the risk of operating in Yemen and we believe that the current risks are manageable.

Item 8. Financial Statements and Supplementary Data.

Our consolidated Financial Statements and notes thereto, the report of our independent auditors and our supplementary financial and operating information are included elsewhere in this Form 10-K.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

We carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934, as amended) as of December 31, 2003. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective to ensure that information required to be disclosed by us in our periodic filings under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms. During the fourth quarter of 2003 there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financing reporting.

PART III

Item 10. Directors and Executive Officers of the Registrant.

The information required by this Item with respect to our Directors is incorporated by reference from the sections of our definitive Proxy Statement for our 2004 Annual Meeting of Stockholders (the Proxy Statement) entitled Election of Directors and Section 16(a) Beneficial Ownership Reporting Compliance. The information required by this Item with respect to our Executive Officers appears at Item 4A of Part I of this Form 10-K.

Code of Ethics. We have adopted a Code of Ethics for our Chief Executive Officer and senior financial officers. The Code of Ethics is publicly available on our website at http://www.vintagepetroleum.com. If we make any substantive amendments to the Code of Ethics or grant any waiver, including any implicit waiver, from a provision of the Code of Ethics to our Chief Executive Officer, Chief Financial Officer or

Corporate Controller, we will disclose the nature of such amendment or waiver on that website.

Item 11. Executive Compensation.

The information required by this Item is incorporated by reference from the sections of our Proxy Statement entitled Election of Directors and Executive Compensation.

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

The information required by this Item, other than the information required by Item 201(d) of Regulation S-K, is incorporated by reference from the section of our Proxy Statement entitled Principal Stockholders and Security Ownership of Management. The information required by Item 201(d) of Regulation S-K is set forth below.

Equity Compensation Plan Information

The following table provides information as of December 31, 2003, concerning shares of our common stock authorized for issuance under our existing equity compensation plans.

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by security holders	3,134,286(1)	$ 10.37(1)	2,088,832(2)
Equity compensation plans not approved by security holders			
Total	3,134,286	$ 10.37	2,088,832

(1) Includes 148,350 shares subject to restricted stock rights. The weighted average exercise price does not take these rights into account.

(2) Represents the total number of shares available for issuance under our 1990 Stock Plan pursuant to stock options, stock appreciation rights or restricted stock or restricted stock rights. All of the 2,088,832 shares available for issuance under our 1990 Stock Plan may be awarded as restricted stock or restricted stock rights. Under the 1990 Stock Plan, 10 percent of the total number of outstanding shares of our common stock, less the total number of shares of our common stock subject to outstanding awards under any other stock-based plan for our employees or our directors, is available for issuance to our key employees and our directors.

Item 13. Certain Relationships and Related Transactions.

The information required by this Item is incorporated by reference from the section of our Proxy Statement entitled Certain Transactions.

Item 14. Principal Accountant Fees and Services.

The information required by this Item is incorporated by reference from the section of our Proxy Statement entitled Ratification of Appointment of Independent Auditor.

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PART IV

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

(a) (1) Financial Statements:

Our consolidated financial statements and report of independent auditors listed in the accompanying Index to Financial Statements are filed as a part of this Form 10-K.

(2) Financial Statements Schedules:

All schedules are omitted because they are inapplicable or because the required information is contained in the financial statements or included in the notes thereto.

(3) Exhibits:

The following documents are included as exhibits to this Form 10-K. Those exhibits below incorporated by reference herein are indicated as such by the information supplied in the parenthetical thereafter. If no parenthetical appears after an exhibit, such exhibit is filed herewith.

3.1	Restated Certificate of Incorporation, as amended, of the Company (Filed as Exhibit 3.2 to the Company s report on Form 10-Q for the quarter ended June 30, 2000, filed August 11, 2000).
3.2	Restated By-laws of the Company (Filed as Exhibit 3.2 to the Company s Registration Statement on Form S-1, Registration No. 33-35289 (the S-1 Registration Statement)).
4.1	Form of stock certificate for Common Stock, par value $0.005 per share (Filed as Exhibit 4.1 to the S-1 Registration Statement).
4.2	Indenture dated as of January 26, 1999, between JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, and the Company (Filed as Exhibit 4.4 to the Company s report on Form 10-K for the year ended December 31, 1998, filed March 12, 1999).
4.3	Indenture dated as of May 30, 2001, between JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, and the Company (Filed as Exhibit 4.1 to the Company s Registration Statement on Form S-4, Registration No. 333-63896).
4.4	Indenture dated as of May 2, 2002, between JPMorgan Chase Bank, as Trustee, and the Company (Filed as Exhibit 4.1 to the Company s Registration Statement on Form S-4, Registration No. 333-89182).
4.5	Rights Agreement, dated March 16, 1999, between the Company and Mellon Investor Services LLC (formerly ChaseMellon Shareholder Services, L.L.C.), as Rights Agent (Filed as Exhibit 4.1 to the Company s Registration Statement on Form 8-A, filed March 22, 1999).
4.6	First Amendment to Rights Agreement, dated as of April 3, 2002, between the Company and Mellon Investor Services LLC (formerly ChaseMellon Shareholder Services, L.L.C.), as Rights Agent (Filed as Exhibit 4.1 to the Company s

Amendment No. 1 to Registration Statement on Form 8-A, filed April 3, 2002).

4.7 Certificate of Designation of Series A Junior Participating Preferred Stock of the Company (Filed as Exhibit 3.3 to the Company s Registration Statement on Form S-3, Registration No. 333-77619).

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10.1*	Form of Indemnification Agreement between the Company and certain of its officers and directors (Filed as Exhibit 10.23 to the S-1 Registration Statement).
10.2*	Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 4(d) to the Company s Registration Statement on Form S-8, Registration No. 33-37505).
10.3*	Amendment No. 1 to Vintage Petroleum, Inc. 1990 Stock Plan, effective January 1, 1991 (Filed as Exhibit 10.15 to the Company s report on Form 10-K for the year ended December 31, 1991, filed March 30, 1992).
10.4*	Amendment No. 2 to Vintage Petroleum, Inc. 1990 Stock Plan dated February 24, 1994 (Filed as Exhibit 10.15 to the Company s report on Form 10-K for the year ended December 31, 1993, filed March 29, 1994).
10.5*	Amendment No. 3 to Vintage Petroleum, Inc. 1990 Stock Plan dated March 15, 1996 (Filed as Exhibit A to the Company s Proxy Statement for Annual Meeting of Stockholders dated April 1, 1996).
10.6*	Amendment No. 4 to Vintage Petroleum, Inc. 1990 Stock Plan dated March 11, 1998 (Filed as Exhibit A to the Company s Proxy Statement for Annual Meeting of Stockholders dated March 31, 1998).
10.7*	Amendment No. 5 to Vintage Petroleum, Inc. 1990 Stock Plan dated March 16, 1999 (Filed as Exhibit A to the Company s Proxy Statement for Annual Meeting of Stockholders dated March 31, 1999).
10.8*	Amendment No. 6 to Vintage Petroleum, Inc. 1990 Stock Plan dated March 17, 2000 (Filed as Exhibit A to the Company s Proxy Statement for Annual Meeting of Stockholders dated March 30, 2000).
10.9*	Vintage Petroleum, Inc. Non-Management Director Stock Option Plan (Filed as Exhibit 10.18 to the Company s report on Form 10-K for the year ended December 31, 1992, filed March 31, 1993 (the 1992 Form 10-K)).
10.10*	Form of Incentive Stock Option Agreement under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.20 to the Company s report on Form 10-K for the year ended December 31, 1990, filed April 1, 1991).
10.11*	Form of Non-Qualified Stock Option Agreement under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.20 to the 1992 Form 10-K).
10.12*	Form of Non-Qualified Stock Option Agreement for non-employee directors under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.13 to the Company s report on Form 10-K for the year ended December 31, 1999, filed March 13, 2000).
10.13*	Form of Restricted Stock Award Agreement under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.3 to the Company s report on Form 10-Q for the quarter ended June 30, 2002, filed August 9, 2002).
10.14*	Form of Restricted Stock Rights Award Agreement under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.1 to the Company s report on Form 10-Q for the quarter ended September 30, 2002, filed November 14, 2002).
10.15	Credit Agreement dated as of May 2, 2002, among the Company, as borrower, and certain commercial lending institutions, as lenders, Bank of Montreal, as agent, and the Syndication Agent and Co-Documentation Agents party thereto (Filed as Exhibit 10.1 to the Company s report on Form 10-Q for the quarter ended June 30, 2002, filed August 9, 2002).

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10.16	First Amendment to Credit Agreement dated as of May 24, 2002, among the Company, as borrower, the lenders party thereto, Bank of Montreal, as administrative agent, Deutsche Bank Trust Company Americas, as syndication agent, and Fleet National Bank, Societe Generale and The Bank of New York, as co-documentation agents (Filed as Exhibit 10.2 to the Company s report on Form 10-Q for the quarter ended June 30, 2002, filed August 9, 2002).
10.17	Second Amendment to Credit Agreement dated as of May 24, 2002, among the Company, as borrower, the lenders party thereto, Bank of Montreal, as administrative agent, Deutsche Bank Trust Company Americas, as syndication agent, and Fleet National Bank, Societe Generale and The Bank of New York, as co-documentation agents (Filed as Exhibit 10.1 to the Company s report on Form 10-Q for the quarter ended June 30, 2003, filed August 8, 2003).
21.	Subsidiaries of the Company.
23.1	Consent of Ernst & Young LLP.
23.2	Consent of Netherland, Sewell & Associates, Inc.
23.3	Consent of DeGolyer and MacNaughton.
23.4	Consent of Outtrim Szabo Associates Ltd.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) and Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) and Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(b) and Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(b) and Section 906 of the Sarbanes-Oxley Act of 2002.

* Management contract or compensatory plan or arrangement.

(b) Reports on Form 8-K.

None.

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SIGNATURES

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

VINTAGE PETROLEUM, INC.

Date: March 12, 2004

By: /s/ C. C. Stephenson, Jr.

C. C. Stephenson, Jr.

Chairman of the Board, President

and Chief Executive Officer

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

Signature	Title	Date
/s/ C. C. Stephenson, Jr. C. C. Stephenson, Jr.	Director, Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)	March 12, 2004
/s/ William L. Abernathy William L. Abernathy	Director, Executive Vice President and Chief Operating Officer	March 12, 2004
/s/ William C. Barnes William C. Barnes	Director, Executive Vice President, Chief Financial Officer, Secretary and Treasurer (Principal Financial Officer)	March 12, 2004
/s/ Rex D. Adams Rex D. Adams	Director	March 12, 2004
/s/ Bryan H. Lawrence Bryan H. Lawrence	Director	March 12, 2004
/s/ Joseph D. Mahaffey Joseph D. Mahaffey	Director	March 12, 2004

/s/ Gerald J. Maier Gerald J. Maier	Director	March 12, 2004
/s/ John T. McNabb, II John T. McNabb, II	Director	March 12, 2004
/s/ Michael F. Meimerstorf Michael F. Meimerstorf	Vice President and Controller (Principal Accounting Officer)	March 12, 2004

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

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REPORT OF INDEPENDENT AUDITORS

To the Board of Directors and Stockholders

of Vintage Petroleum, Inc.:

We have audited the accompanying consolidated balance sheets of Vintage Petroleum, Inc. and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of operations, changes in stockholders equity and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Vintage Petroleum, Inc. and subsidiaries as of December 31, 2003 and 2002, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2003, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*. In addition, as also discussed in Note 1, effective January 1, 2002, the Company adopted the provisions of Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* and effective January 1, 2001, the Company changed its method of accounting for derivatives to adopt the requirements of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*.

ERNST & YOUNG LLP

Tulsa, Oklahoma

February 27, 2004

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(In thousands, except shares and per share amounts)

	December 31, 2003	December 31, 2002
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 54,880	$ 9,259
Accounts receivable -		
Oil and gas sales	89,674	90,267
Joint operations	9,359	9,542
Prepaids and other current assets	14,702	21,021
Assets of discontinued operations		86,174
Total current assets	168,615	216,263
PROPERTY, PLANT AND EQUIPMENT, at cost:		
Oil and gas properties, successful efforts method	2,717,193	2,487,549
Oil and gas gathering systems and plants	23,344	20,588
Other	29,072	26,501
	2,769,609	2,534,638
Less accumulated depreciation, depletion and amortization	1,535,715	1,047,665
Total property, plant and equipment, net	1,233,894	1,486,973
GOODWILL		21,099
OTHER ASSETS, net	44,329	51,469
TOTAL ASSETS	$ 1,446,838	$ 1,775,804

The accompanying notes are an integral part of these statements.

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Continued)

(In thousands, except shares and per share amounts)

	December 31, 2003	December 31, 2002
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Revenue payable	$ 26,654	$ 30,869
Accounts payable - trade	55,601	42,038
Current income taxes payable	19,933	18,722
Derivative financial instrument payable	7,876	17,122
Other payables and accrued liabilities	70,028	59,013
Liabilities of discontinued operations		10,769
Total current liabilities	180,092	178,533
LONG-TERM DEBT	699,943	883,180
DEFERRED INCOME TAXES	54,302	137,015
LONG-TERM LIABILITY FOR ASSET RETIREMENT OBLIGATIONS	89,076	
OTHER LONG-TERM LIABILITIES	939	6,084
COMMITMENTS AND CONTINGENCIES (Note 5)		
STOCKHOLDERS EQUITY, per accompanying statements:		
Preferred stock, $0.01 par, 5,000,000 shares authorized, zero shares issued and outstanding		
Common stock, $0.005 par, 160,000,000 shares authorized, 64,720,975 and 63,432,972 shares issued and 64,281,199 and 63,348,272 shares outstanding	324	317
Capital in excess of par value	337,080	326,510
Retained earnings	22,844	274,971
Accumulated other comprehensive income (loss)	70,482	(28,573)
	430,730	573,225
Less treasury stock, at cost, 439,776 and 84,700 shares	3,117	
Less unamortized cost of restricted stock awards	5,127	2,233
Total stockholders equity	422,486	570,992
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 1,446,838	$ 1,775,804

The accompanying notes are an integral part of these statements.

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	For the Years Ended December 31,		
	2003	**2002**	**2001**
REVENUES AND OTHER INCOME (EXPENSE):			
Oil and gas sales	$ 660,873	$ 577,699	$ 707,090
Gas marketing	98,451	66,516	130,209
Oil and gas gathering and processing	8,089	5,731	17,032
Gain (loss) on disposition of assets	(1,701)	16,546	26,871
Foreign currency exchange gain (loss)	(6,027)	427	1,825
Other income (expense)	(3,358)	(2,656)	1,940
Total revenues and other income (expense)	756,327	664,263	884,967
COSTS AND EXPENSES:			
Production costs	169,878	163,006	182,317
Production, export and ad valorem taxes	49,963	41,287	22,333
Exploration costs	74,932	42,734	21,587
Gas marketing	95,856	64,906	126,373
Oil and gas gathering and processing	9,108	7,501	17,759
General and administrative	57,132	47,969	47,676
Stock compensation	6,057	1,329	454
Depreciation, depletion and amortization	143,695	178,902	165,984
Impairment of proved oil and gas properties	370,244	98,720	29,050
Accretion	7,340		
Amortization of goodwill			11,940
Impairment of goodwill	25,673	76,351	
Interest	69,917	77,714	64,720
Loss on early extinguishment of debt	6,909	8,154	
Total costs and expenses	1,086,704	808,573	690,193
Income (loss) from continuing operations before income taxes and cumulative effect of changes in accounting principles	(330,377)	(144,310)	194,774
PROVISION (BENEFIT) FOR INCOME TAXES:			
Current	43,873	21,684	80,535
Deferred	(115,380)	(60,772)	(12,210)
Total provision (benefit) for income taxes	(71,507)	(39,088)	68,325
Income (loss) from continuing operations before cumulative effect of changes in accounting principles	(258,870)	(105,222)	126,449
INCOME FROM DISCONTINUED OPERATIONS, net of income taxes	10,844	22,105	7,058

Income (loss) before cumulative effect of changes in accounting principles	(248,026)	(83,117)	133,507
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES, net of income tax provision of $4,104, zero and zero, respectively	7,119	(60,547)	
NET INCOME (LOSS)	$ (240,907)	$ (143,664)	$ 133,507

The accompanying notes are an integral part of these statements.

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Continued)

(In thousands, except per share amounts)

	For the Years Ended December 31,		
	2003	**2002**	**2001**
BASIC INCOME (LOSS) PER SHARE:			
Income (loss) from continuing operations before cumulative effect of changes in accounting principles	$ (4.04)	$ (1.66)	$ 2.01
Income from discontinued operations	0.17	0.35	0.11
Income (loss) before cumulative effect of changes in accounting principles	(3.87)	(1.31)	2.12
Cumulative effect of changes in accounting principles	0.11	(0.96)	
Net income (loss)	$ (3.76)	$ (2.27)	$ 2.12
DILUTED INCOME (LOSS) PER SHARE:			
Income (loss) from continuing operations before cumulative effect of changes in accounting principles	$ (4.04)	$ (1.66)	$ 1.98
Income from discontinued operations	0.17	0.35	0.11
Income (loss) before cumulative effect of changes in accounting principles	(3.87)	(1.31)	2.09
Cumulative effect of changes in accounting principles	0.11	(0.96)	
Net income (loss)	$ (3.76)	$ (2.27)	$ 2.09
Weighted average common shares outstanding:			
Basic	64,022	63,219	63,023
Diluted	64,022	63,219	64,027

The accompanying notes are an integral part of these statements.

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY

(In thousands, except treasury shares and per share amounts)

	Common Stock							
	Shares	Amount	Treasury Stock	Capital In Excess of Par Value	Unamortized Restricted Stock Awards	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
BALANCE AT DECEMBER 31, 2000	62,801	$ 314	$	$ 319,893	$	$ 303,449	$ 1,201	$ 624,857
Comprehensive income:								
Transition adjustment for adoption of SFAS 133							14,915	14,915
Net income						133,507		133,507
Foreign currency translation adjustment							(25,823)	(25,823)
Change in value of derivatives							(11,925)	(11,925)
Total comprehensive income								110,674
Exercise of stock options and resulting tax effects	170	1		1,970				1,971
Issuance of restricted stock	110			2,214	(2,214)			
Amortization of restricted stock awards					454			454
Cash dividends declared ($0.135 per share)						(8,513)		(8,513)
BALANCE AT DECEMBER 31, 2001	63,081	315		324,077	(1,760)	428,443	(21,632)	729,443
Comprehensive loss:								
Net loss						(143,664)		(143,664)
Foreign currency translation adjustment							4,965	4,965
Change in value of derivatives							(11,906)	(11,906)
Total comprehensive loss								(150,605)
Exercise of stock options and resulting tax effects	81	1		730				731
Issuance of restricted stock	271	1		2,972	(2,973)			
Amortization of restricted stock awards				204	1,555			1,759
Forfeitures of restricted stock and other (84,700 shares)				(1,473)	945			(528)

Cash dividends declared ($0.155 per share)						(9,808)		(9,808)
BALANCE AT DECEMBER 31, 2002	63,433	317		326,510	(2,233)	274,971	(28,573)	570,992
Comprehensive loss:								
Net loss						(240,907)		(240,907)
Foreign currency translation adjustment							92,208	92,208
Change in value of derivatives							6,847	6,847
Total comprehensive loss								(141,852)
Issuance of stock options				117				117
Exercise of stock options and resulting tax effects	176	1		1,624				1,625
Issuance of restricted stock	1,090	6		8,955	(8,961)			
Amortization of restricted stock awards				865	5,445			6,310
Forfeitures of restricted stock (77,963 shares)				(991)	622			(369)
Vesting of restricted stock rights	22							
Purchase of treasury stock (277,113 shares)			(3,117)					(3,117)
Cash dividends declared ($0.175 per share)						(11,220)		(11,220)
BALANCE AT DECEMBER 31, 2003	64,721	$ 324	$ (3,117)	$ 337,080	$ (5,127)	$ 22,844	$ 70,482	$ 422,486

The accompanying notes are an integral part of these statements.

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	For the Years Ended December 31,		
	2003	**2002**	**2001**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (240,907)	$ (143,664)	$ 133,507
Adjustments to reconcile net income (loss) to cash provided by operating activities, net of companies acquired -			
Income from discontinued operations, net of tax	(10,844)	(22,105)	(7,058)
Cumulative effect of changes in accounting principles	(7,119)	60,547	
Depreciation, depletion and amortization	143,695	178,902	165,984
Impairment of proved oil and gas properties	370,244	98,720	29,050
Amortization of goodwill			11,940
Impairment of goodwill	25,673	76,351	
Accretion	7,340		
Exploration costs	60,960	32,662	11,994
Benefit for deferred income taxes	(115,380)	(60,772)	(12,210)
Foreign currency exchange (gain) loss	6,027	(427)	(1,825)
(Gain) loss on disposition of assets	1,701	(16,546)	(26,871)
Loss on early extinguishment of debt	6,909	8,154	
Stock compensation	6,057	1,329	454
Other non-cash items included in net income (loss)	2,739	2,297	191
Decrease (increase) in receivables	3,060	(25,225)	89,195
Increase (decrease) in payables and accrued liabilities	3,391	25,046	(97,281)
Other working capital changes	10,099	11,502	(16,831)
Cash provided by continuing operations	273,645	226,771	280,239
Cash provided (used) by discontinued operations	(39,812)	14,098	15,446
Cash provided by operating activities	233,833	240,869	295,685
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures -			
Oil and gas properties	(171,837)	(117,439)	(252,285)
Gathering systems and other	(4,273)	(5,672)	(5,767)
Proceeds from sales of oil and gas properties	57,910	23,208	39,800
Purchase of companies, net of cash acquired			(478,158)
Proceeds from sale of company, net of cash sold	116,107	39,314	
Other	3,319	(453)	(8,195)
Cash provided (used) by investing activities - continuing operations	1,226	(61,042)	(704,605)
Cash provided (used) by investing activities - discontinued operations	10,309	(13,211)	(9,232)

Cash provided (used) by investing activities	11,535	(74,253)	(713,837)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Issuance of common stock	1,625	731	1,231
Purchase of treasury stock	(3,117)		
Issuance of 7 7/8% Senior Subordinated Notes Due 2011			199,930
Issuance of 8 1/4% Senior Notes Due 2012		350,000	
Redemption of 9% Senior Subordinated Notes Due 2005	(50,750)	(103,000)	
Redemption of 8 5/8% Senior Subordinated Notes Due 2009	(103,234)		
Advances on revolving credit facility and other borrowings	289,100	289,400	319,050
Payments on revolving credit facility and other borrowings	(322,900)	(678,892)	(88,431)
Dividends paid	(10,862)	(9,484)	(8,187)
Transaction costs on debt issuance and other	(1,753)	(10,668)	
Cash provided (used) by financing activities	(201,891)	(161,913)	423,593
EFFECT OF EXCHANGE RATE CHANGE ON CASH	2,144	(1,803)	(429)
NET INCREASE IN CASH AND CASH EQUIVALENTS	45,621	2,900	5,012
CASH AND CASH EQUIVALENTS, beginning of year	9,259	6,359	1,347
CASH AND CASH EQUIVALENTS, end of year	$ 54,880	$ 9,259	$ 6,359

The accompanying notes are an integral part of these statements.

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the Years Ended December 31, 2003, 2002 and 2001

1. Business and Significant Accounting Policies

Vintage Petroleum, Inc. is an independent energy company with operations primarily in the exploration and production, gas marketing, gas processing and gathering segments of the oil and gas industry. The Company s North American exploration and production operations include the West Coast, Gulf Coast, East Texas and Mid-Continent areas of the United States and the western sedimentary basins of Canada. The Company also has core areas of operations in the San Jorge Basin and Cuyo Basin of Argentina and the Chaco Basin in Bolivia. The Company has exploration activities currently ongoing in Yemen, Italy and Bulgaria. The Company sold its exploration and production operations in Trinidad and Ecuador in July 2002 and January 2003, respectively (see Note 9).

Consolidation and Presentation

The consolidated financial statements include the accounts of Vintage Petroleum, Inc., its wholly- and majority-owned subsidiaries and its proportionately consolidated general partner and limited partner interests in various joint ventures (collectively, the Company). All significant intercompany accounts and transactions have been eliminated in consolidation. Certain 2001 and 2002 amounts have been reclassified to conform with the 2003 presentation. These reclassifications had no effect on the Company s net income (loss) or stockholders equity.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Oil and Gas Properties

Under the successful efforts method of accounting, the Company capitalizes all costs related to property acquisitions and successful exploratory wells, all development costs and the costs of support equipment and facilities. Certain costs of exploratory wells are capitalized pending determination that proved reserves have been found. Such determination may be dependent upon the results of planned additional wells and the cost of required capital expenditures to produce the reserves found. All costs related to unsuccessful exploratory wells are expensed when such wells are determined to be non-productive; other exploration costs, including geological and geophysical costs, are expensed as incurred. Delineation seismic costs incurred to select development locations within a productive oil and gas field are capitalized. Capitalized development seismic costs for the years ended December 31, 2003, 2002 and 2001, were $2.5 million, $1.7 million and $9.5 million, respectively. The

Company recognizes gains or losses on the sale of properties on a field basis.

Unproved leasehold costs are capitalized and reviewed periodically for impairment. Individual unproved properties whose acquisition costs are significant are assessed on a property-by-property basis, considering factors such as future drilling and exploitation plans and lease terms. For unproved properties whose acquisition costs are not individually significant, the amount of those properties impairment is determined by amortizing the properties in groups on the basis of the Company s experience in similar situations and other information such as the primary lease terms, the average holding period of unproved properties and the relative proportion of such properties on which proved reserves have been found in the past. Costs related to impaired prospects are charged to expense and included in exploration costs in the accompanying statements of operations. The Company recorded leasehold impairments of $45.9 million, $12.2 million and $5.3 million in 2003, 2002 and 2001, respectively, including $23.7 million in 2003 to fully impair the Company s undeveloped leaseholds in the Northwest Territories. Additional impairment expense could result if oil and gas prices decline in the future or if downward reserve revisions are recorded on nearby properties, as it may not be economic to develop some of these unproved properties.

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

As of December 31, 2003, the Company had total unproved oil and gas property costs of approximately $58.2 million, consisting of undeveloped leasehold costs of $39.2 million, including $29.7 million in Canada, and unevaluated exploratory drilling costs of $19.0 million. Approximately $11.8 million of the total unevaluated costs are associated with the Company s exploration drilling program in Yemen.

Costs of development dry holes and proved leaseholds are amortized on the unit-of-production method using proved reserves on a field basis. The depreciation of capitalized production equipment, drilling costs and asset retirement obligations is based on the unit-of-production method using proved developed reserves on a field basis.

In August 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143). The Company was required to adopt this new standard beginning January 1, 2003. Through December 31, 2002, the Company accrued an estimate of future abandonment costs of wells and related facilities through its depreciation calculation and included the cumulative accrual in accumulated depreciation in accordance with the provisions of Statement of Financial Accounting Standards No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, and industry practice. At December 31, 2002, approximately $54.6 million of accrued future abandonment costs were included in accumulated depreciation. The new standard requires that the Company record the discounted fair value of the retirement obligation as a liability at the time a well is drilled or acquired. The asset retirement obligations consist primarily of costs associated with the plugging and abandonment of oil and gas wells, site reclamation and facilities dismantlement. However, future abandonment liabilities are also recorded for other assets such as pipelines, processing plants and compressors. A corresponding amount is capitalized as part of the related property s carrying amount. The discounted capitalized asset retirement cost is amortized to expense through the depreciation calculation over the estimated useful life of the asset based on proved developed reserves. The liability accretes over time with a charge to accretion expense. At January 1, 2003 and December 31, 2003, there were no assets legally restricted for purposes of settling asset retirement obligations.

The Company adopted SFAS 143 effective January 1, 2003, and recorded an increase in property, plant and equipment of approximately $50.3 million, a decrease in accumulated depreciation, depletion and amortization of approximately $43.9 million, an increase in current asset retirement liabilities of approximately $4.5 million, an increase in long-term asset retirement liabilities of approximately $78.5 million, a $4.1 million increase in deferred income tax liabilities and a non-cash gain as a result of the cumulative effect of change in accounting principle, net of tax, of approximately $7.1 million.

Subsequent to the implementation of SFAS 143, the Company recorded the following activity related to the liability (in thousands):

Initial liability for asset retirement obligations as of January 1, 2003	$ 83,040
New obligations for wells drilled	1,788
Costs incurred	(3,348)
Reversal of liability for sales of oil and gas properties	(3,225)
Accretion expense	7,340
Changes in foreign currency exchange rates	3,191

Revisions in estimated cash flows	6,100
Liability for asset retirement obligations as of December 31, 2003	$ 94,886

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Of the liability for asset retirement obligations balance at December 31, 2003, approximately $5.8 million is classified as current and included in Other payables and accrued liabilities in the accompanying balance sheet.

Had the provisions of SFAS 143 been applied in 2002 and 2001, the liability for asset retirement obligations would have been $68.9 million at January 1, 2001, $75.7 million at December 31, 2001, and $83.0 million at December 31, 2002, and the Company s net income (loss) and earnings per share would have been as follows (in thousands, except per share amounts):

	Years Ended			
	December 31, 2002		December 31, 2001	
	As Reported	Pro Forma	As Reported	Pro Forma
Net income (loss)	$ (143,664)	$ (148,719)	$ 133,507	$ 134,704
Income (loss) per share:				
Basic	$ (2.27)	$ (2.35)	$ 2.12	$ 2.14
Diluted	$ (2.27)	$ (2.35)	$ 2.09	$ 2.11

The Company reviews its proved oil and gas properties for impairment on a field basis. For each field, an impairment provision is recorded whenever events or circumstances indicate that the carrying value of those properties may not be recoverable from estimated future net revenues. The impairment provision is based on the excess of carrying value over fair value. Fair value is defined as the present value of the estimated future net revenues from production of total proved and risk-adjusted probable and possible oil and gas reserves over the economic life of the reserves, based on the Company s expectations of future oil and gas prices and costs, consistent with price and cost assumptions used for acquisition evaluations. The Company recorded impairment provisions related to its proved oil and gas properties of $370.2 million, $98.7 million and $29.1 million in 2003, 2002 and 2001, respectively. These impairments resulted from downward revisions in the estimates of proved oil and gas reserves in certain U.S. and Canadian properties in the second, third and fourth quarters of 2003, and the fourth quarters of 2002 and 2001. Disappointing results in Canada during 2003 led to significant downward reserve revisions at year end 2003. Results of the Company s work programs and production performance of certain producing properties during the latter part of 2003 resulted in revisions to reserves previously booked to specific wells or to reserves associated with future activities. Due to these disappointing results, in connection with its normal year end reserve estimation process, the Company performed a critical review to revise or re-validate all remaining future activities on its Canadian proved reserve base. As a result of this review, the Company determined that previously planned exploration and development activities would be scaled back or eliminated.

On January 1, 2002, the Company adopted the provisions of Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS 144). SFAS 144 creates accounting and reporting standards to establish a single accounting model, based on the framework established in Statement of Financial Accounting Standards No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of*, for long-lived assets to be disposed of by sale. The adoption of SFAS 144 did not have a material impact on the Company s financial position or results of operations. See the further discussion of discontinued operations in

Note 9.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the purchase of Genesis Exploration Ltd. (Genesis) in May 2001 (see Note 8). In 2001, goodwill was amortized using the unit-of-production basis over the total proved reserves acquired. Accumulated amortization was approximately $11.9 million at December 31, 2001. The Company assessed the recoverability of goodwill by determining whether the net book value of goodwill could be recovered through the aggregate of the excess of undiscounted future net revenues of the acquired properties over the net book value of those properties. The estimated future net revenues of the acquired properties included production of total proved and risk-adjusted probable and possible oil and gas reserves over the economic life of the reserves, based on the Company s expectation of future oil and gas prices and costs, consistent with price and cost assumptions used for acquisition evaluations. There was no impairment of goodwill in 2001 under this method.

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On July 20, 2001, the FASB issued Statement of Financial Accounting Standards No. 141, *Business Combinations* (SFAS 141), and Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* (SFAS 142). SFAS 141 requires all business combinations initiated after June 30, 2001, to be accounted for using the purchase method of accounting. Under SFAS 142, goodwill is no longer subject to amortization. Rather, goodwill is subject to at least an annual assessment for impairment by applying a fair-value based test. Additionally, an acquired intangible asset should be separately recognized if the benefit of the intangible asset is obtained through contractual or other legal rights, or if the intangible asset can be sold, transferred, licensed, rented or exchanged, regardless of the acquirer s intent to do so.

The Company s acquisition of Genesis was accounted for using the purchase method of accounting. The Company adopted SFAS 141 and SFAS 142 effective January 1, 2002, resulting in the elimination of goodwill amortization from statements of operations in future periods. Upon adoption, the Company recorded an impairment charge of $60.5 million related to the goodwill of its Canadian operations as a cumulative effect of a change in accounting principle in its statement of operations (see Note 4). The Company recorded additional operating expenses for goodwill impairment charges of $25.7 million and $76.4 million at December 31, 2003 and 2002, respectively. The Company had no remaining goodwill recorded at December 31, 2003.

Revenue Recognition

Natural gas revenues are recorded using the sales method. Under this method, the Company recognizes revenues based on actual volumes of gas sold to purchasers. The Company and other joint interest owners may sell more or less than their entitlement share of the natural gas volumes produced. A liability is recorded and revenue is deferred if the Company s excess sales of natural gas volumes exceed its estimated remaining recoverable reserves. Oil revenues are recognized at the time of delivery to pipelines or at the time of physical transfer to the purchaser. Oil inventories held in storage facilities are valued at cost. Transportation and storage costs are included in production costs and totaled $8.4 million, $8.8 million, and $10.3 million for the years ended December 31, 2003, 2002 and 2001, respectively.

Hedging

The Company periodically uses derivative financial instruments as hedges to reduce the impact of oil and natural gas price fluctuations. The Company accounts for its hedging activities under the provisions of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (as amended, SFAS 133). SFAS 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS 133 requires that changes in the derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative s gains and losses to offset related results on the hedged item in the statement of operations. Companies must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

For derivative financial instruments that qualify as cash flow hedges, the effective portion of the gain or loss on a derivative instrument is reported as a component of other comprehensive income and reclassified into sales revenue in the same period or periods during which the hedged forecasted transaction affects earnings. The effective portion is determined by comparing the cumulative change in fair value of the derivative to the cumulative change in the present value of the expected cash flows of the item being hedged. To the extent the cumulative change in the fair value of the derivative exceeds the cumulative change in the present value of expected cash flows, the excess is recognized currently in earnings. If the cumulative change in present value of the expected cash flows exceeds the change in fair value of the derivative, the difference is ignored. Changes in the fair value of derivative financial instruments that do not qualify for accounting treatment as hedges, if any, are recognized currently as Other income (expense). The cash flows from such agreements are included in operating activities in the consolidated statements of cash flows.

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Upon adoption of SFAS 133 on January 1, 2001, the Company recorded a transition receivable of $18.5 million related to cash flow hedges in place that were used to reduce the volatility in commodity prices for portions of the Company s forecasted oil production. Additionally, the Company recorded, net of tax, an adjustment to accumulated other comprehensive income in the Stockholders Equity section of the balance sheet of approximately $14.9 million. The amount recorded to accumulated other comprehensive income was relieved and recorded in the statement of operations as the physical transactions being hedged impacted earnings. All of the Company s cash flow hedges in place at January 1, 2001, had settled as of December 31, 2001, with the actual cash flow impact recorded in oil and gas sales in the Company s statement of operations. During 2003, 2002 and 2001, the Company recorded losses related to hedge ineffectiveness, net of tax, of $0.4 million, $0.8 million and $0.1 million, respectively. Beginning October 26, 2003, a portion of the Company s oil and gas production in Ventura County, California was shut-in as a result of fires in the area. The Company had designated oil sales from this area as hedged transactions for the first three months of 2004. Although oil and gas production in this area is increasing as repairs are made, at December 31, 2003, the Company determined that the occurrence of the forecasted transaction in the hedges was no longer probable for the first three months of 2004. Accordingly, at December 31, 2003, the Company reclassified approximately $0.9 million of derivative losses from accumulated other comprehensive income to Other income (expense) in the accompanying statements of operations. The Company did not discontinue any other hedges because of the probability that the original forecasted transaction would not occur.

Depreciation

Depreciation of property, plant and equipment (other than oil and gas properties) is provided using the straight-line method based on estimated useful lives ranging from three to seven years.

Income Taxes

Deferred income taxes are provided on transactions which are recognized in different periods for financial and tax reporting purposes. Such temporary differences arise primarily from the deduction of certain oil and gas exploration and development costs which are capitalized for financial reporting purposes and from differences in the methods of depreciation. Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Statements of Cash Flows

Cash equivalents consist of highly liquid money-market mutual funds and bank deposits with initial maturities of three months or less.

During the years ended December 31, 2003, 2002 and 2001, the Company made cash payments for interest totaling $67.9 million, $74.2 million and $58.6 million, respectively. Cash payments for U.S. income taxes of $48.7 million (primarily related to discontinued operations; see Note 9), $0.6 million and $24.1 million were made during 2003, 2002 and 2001, respectively. The Company made cash payments of $48.4 million, $12.0 million and $77.8 million during 2003, 2002 and 2001 for foreign income taxes, primarily in Argentina.

In May 2001, the Company purchased 100 percent of the outstanding common stock of Genesis (see Note 8). The total purchase price included both cash and the assumption of $154.1 million in net liabilities. These net liabilities are not reflected in the Company s 2001 statement of cash flows.

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Income (Loss) Per Share

Basic income (loss) per common share was computed by dividing net income (loss) by the weighted average number of shares outstanding during the period. Diluted income (loss) per common share was computed assuming the exercise of all dilutive options, as determined by applying the treasury stock method. For 2001, there were approximately 1,004,000 dilutive options. For 2003 and 2002, the assumed exercise of any options would have been anti-dilutive. Therefore, the amounts reported for basic and diluted income (loss) per share were the same. Had the Company been in a net income position for 2003, the Company s diluted weighted average outstanding common shares would have been 65,563,194, with additional options for 796,900 shares of the Company s common stock, at an average exercise price of $15.45, which would have been anti-dilutive. Had the Company been in a net income position for 2002, the Company s diluted weighted average outstanding common shares would have been 63,728,911, with additional options for 3,333,200 shares of the Company s common stock at an average exercise price of $18.31, which would have been anti-dilutive. For the year ended December 31, 2001, the Company had outstanding stock options for 3,244,400 additional shares of the Company s common stock, with an average exercise price of $19.22, which were anti-dilutive. The anti-dilutive options will dilute basic income per share in the future, if exercised, and may impact diluted income per share in the future depending on the market price of the Company s common stock.

General and Administrative Expense

The Company receives fees for the operation of jointly-owned oil and gas properties and records such reimbursements as reductions of general and administrative expense. Such fees totaled approximately $3.9 million, $5.3 million and $6.2 million in 2003, 2002 and 2001, respectively.

Production, Export and Ad valorem Taxes

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 maximum term of five years. The tax of 20 percent is applied on the sales value after the tax, thus the net effect is 16.7 percent. The export tax is not deducted in the calculation of royalty payments.

Included in production, export and ad valorem taxes are the following items (in thousands):

	Years Ended December 31,

	2003	2002	2001
Argentina oil export taxes	$ 31,041	$ 24,824	$
Gross production taxes	11,809	9,887	15,345
Ad valorem taxes	7,113	6,576	6,988

Revenue Payable

Amounts payable to royalty and working interest owners resulting from sales of oil and gas from jointly-owned properties and from purchases of oil and gas by the Company s marketing and gathering segments are classified as revenue payable in the accompanying financial statements.

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Accounts Receivable

The Company s oil and gas, gas marketing and gathering sales are made to a variety of purchasers, including intrastate and interstate pipelines or their marketing affiliates, independent marketing companies and state-owned and major oil companies. The Company s joint operations accounts receivable are from a large number of major and independent oil companies, partnerships, individuals and others who own interests in the properties operated by the Company. This concentration of customers and joint interest owners may impact the Company s overall credit risk since those entities may be similarly affected by industry-wide changes in economic or other conditions. Such receivables are not collateralized, non-interest bearing and are generally settled in less than 60 days. The Company has not historically incurred any significant bad debts on such receivables.

Foreign Currency

Foreign currency transactions and financial statements are translated in accordance with Statement of Financial Accounting Standards No. 52, *Foreign Currency Translation*. All of the Company s subsidiaries use the U.S. dollar as their functional currency except for the Company s Canadian operating subsidiary, which uses the Canadian dollar. Adjustments arising from translation of the Canadian operating subsidiary s financial statements are reflected in other comprehensive income (loss). Transaction gains and losses that arise from exchange rate fluctuations applicable to transactions denominated in a currency other than the Company s or its subsidiaries functional currency are included in the results of operations as incurred.

International investments represent, and are expected to continue to represent, a significant portion of the Company s business. The Company s operations in Argentina represented approximately 35 percent of its 2003 total revenues and approximately 48 percent and 37 percent of the Company s total proved reserves and total assets, respectively, at December 31, 2003.

Beginning in 1991, the Argentine peso (peso) was tied to the U.S. dollar at a rate of one peso to one U.S. dollar. As a result of economic instability and substantial withdrawals from the banking system, the Argentine government instituted restrictions in early December 2001 that prohibit certain foreign money transfers without Central Bank approval and limit cash withdrawals from bank accounts to personal transactions in small amounts with certain limited exceptions. While the legal exchange rate remained at one peso to one U.S. dollar, financial institutions were allowed to conduct only limited activity due to these controls, and currency exchange activity was effectively halted except for personal transactions in small amounts. These actions by the government, in effect, caused a devaluation of the peso in December 2001.

Because exchangeability of the peso was lacking from early December 2001 to January 11, 2002, the Company used the estimated exchange rate of 1.65 pesos to one U.S. dollar at January 11, 2002, (the first rate subsequent to year end at which exchanges could be made) to translate peso-denominated balances at December 31, 2001, and peso-denominated transactions during December 2001. This translation increased 2001 net income by approximately $3.3 million, consisting of a foreign currency exchange gain of approximately $2.3 million (included in Other income (expense) on the statement of operations) and approximately $1.0 million in reductions of certain operating expenses during December 2001.

On January 6, 2002, the Argentine government abolished the legal exchange rate of one peso to one U.S. dollar. On January 9, 2002, Decree 71 created a dual exchange market whereby foreign trade transactions were conducted at an official exchange rate of 1.4 pesos to one U.S. dollar and other transactions were conducted in a free floating exchange market. On February 8, 2002, Decree 260 unified the dual exchange markets and allowed the peso to float freely with the U.S. dollar. The exchange rate at December 31, 2003, was 2.94 pesos to one U.S. dollar and the exchange rate at December 31, 2002, was 3.38 pesos to one U.S. dollar.

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On February 3, 2002, Decree 214 required certain contracts that were previously payable in U.S. dollars to be payable in pesos. Pursuant to an emergency law passed on January 10, 2002, U.S. dollar obligations between private parties due after January 6, 2002, were to be liquidated in pesos at a negotiated rate of exchange which reflected a sharing of the impact of the devaluation. The Company s settlements in pesos of the existing U.S. dollar-denominated agreements have been completed, thus future periods will not be impacted by this mandate. This government-mandated equitable sharing of the impact of the devaluation resulted in a reduction in oil revenues from domestic sales in Argentina for 2002 of approximately $8 million, or $0.73 per Argentine barrel produced or $0.38 per total Company barrel produced. The Company s Argentine production costs were also reduced as a result of this mandate and the positive impact of devaluation on the Company s peso-denominated costs essentially offset the negative impact on Argentine oil revenues. Absent the January 10, 2002, emergency law, the devaluation of the peso would have had no effect on the U.S. dollar-denominated payables and receivables at December 31, 2001. A $0.9 million gain resulting from the involuntary conversion was recorded in January 2002.

The Company has evaluated the effect of the economic and political events in Argentina and the Company continues to believe that the facts and circumstances indicate that the U.S. dollar remains the functional currency of its Argentine operations.

Stock Compensation

The Company has two fixed stock-based compensation plans, as more fully described in Note 3, which reserve shares of common stock for issuance to key employees and directors. Prior to 2003, the Company accounted for these plans under the recognition and measurement provisions of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* and related interpretations. Compensation for restricted stock awards is recorded over the vesting periods of the awards. No stock compensation expense related to stock options granted prior to 2003 has been recognized, as all options granted under these plans had an exercise price equal to the market value of the underlying common stock on the grant date.

Effective January 1, 2003, the Company has adopted the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation* (SFAS 123). The Company adopted these provisions prospectively and applied them to all employee and director awards granted, modified, or settled after January 1, 2003. Stock option awards under the Company s plans generally vest over three years, therefore, the cost related to stock compensation included in the determination of net income (loss) for 2003, 2002 and 2001 is less than that which would have been recognized if the fair value based method had been applied to all awards since the original effective date of SFAS 123. The following table illustrates the effect on net income (loss) and earnings (loss) per share if the fair value based method had been applied to all outstanding and unvested awards in each period (in thousands, except per share amounts):

	Years Ended December 31,		
	2003	**2002**	**2001**

Stock compensation expense - as reported	$ 6,057	$ 1,329	$ 454
Stock compensation expense - pro forma	6,716	5,775	6,255
Net income (loss) - as reported	(240,907)	(143,664)	133,507
Net income (loss) - pro forma	(241,436)	(146,889)	129,237
Income (loss) per share - as reported:			
Basic	(3.76)	(2.27)	2.12
Diluted	(3.76)	(2.27)	2.09
Income (loss) per share - pro forma:			
Basic	(3.77)	(2.32)	2.05
Diluted	(3.77)	(2.32)	2.02

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The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. The weighted average assumptions used for options granted in 2003 include a dividend yield of 1.6 percent, expected volatility of approximately 43.9 percent, a risk-free interest rate of approximately 2.6 percent and expected lives of 4.5 years. The weighted average assumptions used for options granted in 2002 include a dividend yield of 1.4 percent, expected volatility of approximately 50.3 percent, a risk-free interest rate of approximately 4.4 percent and expected lives of 4.5 years. The weighted average assumptions used for options granted in 2001 include a dividend yield of 0.7 percent, expected volatility of approximately 49.1 percent, a risk-free interest rate of approximately 4.7 percent and expected lives of 4.5 years.

Compensation expense related to restricted stock awards is measured based on the stock price on the date of grant of the awards. The Company accrues compensation expense over the vesting period of the restricted stock awards. Forfeitures are recognized as a reduction of compensation expense as they occur.

Comprehensive Income (Loss)

Comprehensive income (loss) consists of the following (in thousands):

	Years Ended December 31,		
	2003	**2002**	**2001**
Net income (loss)	$ (240,907)	$ (143,664)	$ 133,507
Transition adjustment for adoption of SFAS 133			14,915
Foreign currency translation adjustments	92,208	4,965	(25,823)
Changes in value of derivatives, net of tax	6,847	(11,906)	(11,925)
Comprehensive income (loss)	$ (141,852)	$ (150,605)	$ 110,674

The foreign currency translation adjustments shown above relate entirely to the translation of the financial statements of the Company s Canadian operating subsidiary from its functional currency (the Canadian dollar) to the Company s reporting currency (the U.S. dollar).

The changes in the value of derivatives, net of tax, consist of the following (in thousands):

	Years Ended December 31,		
	2003	2002	2001
Reclassification of cumulative effect of adoption of SFAS 133 for (gains) losses included in net income (loss)	$	$	$ (18,540)
Unrealized gain (loss) during the period	(5,141)	(15,692)	4,894
Reclassification adjustment for (gains) losses included in net income (loss)	15,692	(4,894)	
	10,551	(20,586)	(13,646)
Income tax expense (benefit)	3,704	(8,680)	(1,721)
Changes in value of derivatives, net of tax	$ 6,847	$ (11,906)	$ (11,925)

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The accumulated balance for each item in accumulated other comprehensive income (loss) is as follows (in thousands):

	December 31,	
	2003	2002
Foreign currency translation adjustments	$ 72,551	$ (19,657)
Changes in value of derivatives, net of tax	(2,069)	(8,916)
	$ 70,482	$ (28,573)

Approximately $0.7 million of the accumulated balance for the change in value of derivatives, net of tax at December 31, 2003, will be reclassified into net income in 2004.

Treasury stock

Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares is reduced by the average purchase price per share of the aggregate treasury shares held.

New Accounting Pronouncements

In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51* and revised this interpretation in December 2003 (FIN 46). FIN 46 requires the consolidation of variable interest entities by their primary beneficiary if the variable interest entities do not effectively disperse risks among the parties involved. Previously, entities were generally consolidated by an enterprise when it had a controlling financial interest through ownership of a majority of voting interest in the entity. The adoption of FIN 46 had no impact on the Company s financial position or results of operations.

On April 30, 2003, the FASB issued Statement of Financial Accounting Standards No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* (SFAS 149). SFAS 149 is intended to result in more consistent reporting of contracts as either freestanding derivative instruments subject to SFAS 133 in its entirety, or as hybrid instruments with debt host contracts and embedded derivative features.

SFAS 149 was effective for contracts entered into or modified after June 30, 2003, and hedging relationships designated after June 30, 2003. The adoption of SFAS 149 had no impact on the Company s financial position or results of operations.

On May 15, 2003, the FASB issued Statement of Financial Accounting Standards No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* (SFAS 150). SFAS 150 establishes standards for classifying and measuring as liabilities certain financial instruments that embody obligations of the issuer and have characteristics of both liabilities and equity. SFAS 150 must be applied immediately to instruments entered into or modified after May 31, 2003, and to all other instruments that exist as of the beginning of the first interim financial reporting period beginning after June 15, 2003. Early adoption of SFAS 150 is not permitted. The adoption of SFAS 150 had no impact on the Company s financial position or results of operations.

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2. Long-term Debt

Long-term debt at December 31, 2003 and 2002, consisted of the following (in thousands):

	December 31,	
	2003	2002
Revolving credit facility	$	$ 33,800
8 1/4% Senior Notes due 2012	350,000	350,000
Senior subordinated notes:		
9% Notes due 2005, less unamortized discount		49,958
8 5/8% Notes due 2009, less unamortized discount		99,484
9 3/4% Notes due 2009	150,000	150,000
7 7/8% Notes due 2011, less unamortized discount	199,943	199,938
	$ 699,943	$ 883,180

In February 2004, the Company advanced funds under its revolving credit facility to redeem the entire principal balance of the 9 3/4% Senior Subordinated Notes due 2009. Subsequently, cash on hand was used to repay a portion of the outstanding balance under the revolving credit facility. The revolving credit facility matures in 2005 and all other debt matures in 2011 or later. The Company had $7.4 million and $11.7 million of accrued interest payable related to its long-term debt at December 31, 2003 and 2002, respectively, which was included in Other payables and accrued liabilities.

Revolving Credit Facility

The Company has available a senior secured revolving credit facility under a credit agreement, as amended, with certain banks (the Bank Facility). The Bank Facility establishes a borrowing base ($300 million at December 31, 2003) based on the banks evaluation of the Company s oil and gas reserves. The amount available to be borrowed under the Bank Facility is limited to the lesser of the borrowing base or the facility size, which is also currently set at $300 million. The next borrowing base determination will be in April 2004. At December 31, 2003, the unused availability under the Bank Facility (considering outstanding letters of credit of approximately $1.1 million) was approximately $298.9 million.

Outstanding advances under the Bank Facility bear interest payable quarterly at a floating rate based on Bank of Montreal s alternate base rate (as defined therein) or, at the Company s option, at a fixed rate for up to six months based on the Eurodollar market rate (LIBOR). The Company s interest rate increments above the alternate base rate and LIBOR vary based on the level of outstanding senior secured debt to the borrowing base. In addition, the Company must pay a commitment fee of 0.50 percent per annum on the unused portion of the banks commitment. There were no outstanding advances at December 31, 2003.

The Company s borrowing base is redetermined on a semi-annual basis by the banks based on their review of the Company s oil and gas reserves. If the sum of outstanding senior secured debt exceeds the borrowing base, as redetermined, the Company must repay such excess. Any principal advances outstanding are due at maturity on May 2, 2005. The Bank Facility is secured by a first priority lien on the Company s U.S. oil and gas properties, constituting at least 80 percent of the present value of the Company s U.S. proved reserves owned now or in the future. The Bank Facility will be guaranteed by any of the Company s existing and future U.S. subsidiaries that grant a lien on oil and gas properties under the Bank Facility.

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The terms of the Bank Facility impose certain restrictions on the Company regarding the pledging of assets and limitations on additional indebtedness. In addition, the Bank Facility requires the maintenance of a minimum current ratio (as defined therein) and a minimum tangible net worth (as defined therein). The Company was in compliance with all of the covenants under the Bank Facility at December 31, 2003.

In conjunction with the elimination of the Company s previously existing revolving credit facility and the partial redemption of the 9% Senior Subordinated Notes due 2005 (the 9% Notes) in May 2002, the Company was required to expense certain associated deferred financing costs and discounts. This $5.2 million non-cash charge, along with a $3.0 million cash charge for the call premium on the 9% Notes, resulted in a one-time charge of approximately $8.2 million ($5.0 million net of tax) in the second quarter of 2002.

Senior Notes

On May 2, 2002, the Company issued, through a Rule 144A offering, $350 million of its 8 1/4% Senior Notes due 2012 (the 8 1/4% Notes). All of the net proceeds were used to repay a portion of the outstanding balance under the Company s revolving credit facility and to redeem $100 million of the Company s outstanding 9% Notes. The 8 1/4% Notes are redeemable at the option of the Company, in whole or in part, at any time on or after May 1, 2007. In addition, on or before May 1, 2005, the Company may redeem up to 35 percent of the 8 1/4% Notes with the proceeds of certain underwritten public offerings of the Company s common stock. The 8 1/4% Notes mature on May 1, 2012, with interest payable semi-annually on May 1 and November 1 of each year.

Upon a change in control of the Company (as defined in the applicable indentures), holders of the 8 1/4% Notes and the Company s senior subordinated notes (collectively, the Notes) may require the Company to repurchase all or a portion of the Notes at a purchase price equal to 101 percent of the principal amount thereof, plus accrued and unpaid interest. The indentures for the Notes contain limitations on, among other things, additional indebtedness and liens, the payment of dividends and other distributions, certain investments and transfers or sales of assets. The Company was in compliance with all of the covenants under the bond indentures at December 31, 2003.

Senior Subordinated Notes

On December 20, 1995, the Company issued $150 million of its 9% Notes. The 9% Notes were redeemable at the option of the Company, in whole or in part, at any time on or after December 15, 2000. In May 2002, the Company redeemed $100 million of the 9% Notes and redeemed the remaining $50 million of the 9% Notes in March 2003. In conjunction with the redemption of the remaining 9% Notes, the Company was required to expense certain associated deferred financing costs and discounts. This $0.7 million non-cash charge, along with a $0.7 million cash charge for the call premium on the 9% Notes, resulted in a one-time charge of approximately $1.4 million ($0.9 million net of tax), in the first quarter of 2003.

On February 5, 1997, the Company issued $100 million of its 8 5/8% Senior Subordinated Notes due 2009 (the 8 5/8% Notes). The 8 5/8% Notes were redeemable at the option of the Company, in whole or in part, at any time on or after February 1, 2002. In October 2003, the Company redeemed the entire $100 million principal balance of the 8 5/8% Notes due 2009 with cash provided by advances under the revolving credit facility. As a result, the Company was required to expense certain associated deferred financing costs and discounts. This $2.3 million non-cash charge and a $3.2 million cash charge for the call premium resulted in a one-time charge of approximately $5.5 million ($3.4 million net of tax) in the fourth quarter of 2003.

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On January 26, 1999, the Company issued $150 million of its 9 3/4% Senior Subordinated Notes due 2009 (the 9 3/4% Notes). The 9 3/4% Notes were redeemable at the option of the Company, in whole or in part, at any time on or after February 1, 2004. In February 2004, the Company redeemed the entire $150 million principal balance of the 9 3/4% Notes due 2009 with cash provided by advances under the revolving credit facility. As a result, the Company was required to expense certain associated deferred financing costs. The $2.8 million non-cash charge and a $7.3 million cash charge for the call premium resulted in a one-time charge of approximately $10.1 million ($6.2 million net of tax) that the Company will record in the first quarter of 2004.

On May 30, 2001, the Company issued $200 million of its 7 7/8% Senior Subordinated Notes due 2011 (the 7 7/8% Notes). The 7 7/8% Notes are redeemable at the option of the Company, in whole or in part, at any time on or after May 15, 2006. In addition, prior to May 15, 2004, the Company may redeem up to 35 percent of the 7 7/8% Notes with the proceeds of certain underwritten public offerings of the Company s common stock. The 7 7/8% Notes mature on May 15, 2011, with interest payable semi-annually on May 15 and November 15 of each year. All of the net proceeds to the Company from the sale of the 7 7/8% Notes (approximately $199.9 million) were used to repay a portion of the existing indebtedness under the Company s revolving credit facility.

The 9 3/4% Notes and 7 7/8% Notes are unsecured senior subordinated obligations of the Company, rank subordinate in right of payment to all senior indebtedness (as defined) and rank pari passu with each other.

3. Capital Stock

Stock Plans

The Company has two fixed stock-based compensation plans. Under the 1990 Stock Plan, as amended (the 1990 Plan), 10 percent of the total number of outstanding shares of common stock, less the total number of shares of common stock subject to outstanding awards under any other stock-based plan for employees or directors of the Company, is available for issuance to key employees and directors of the Company. The 1990 Plan permits the granting of any or all of the following types of awards: (a) stock options, (b) stock appreciation rights and (c) restricted stock and restricted stock rights (collectively, restricted stock awards). As of December 31, 2003, awards for a total of 2,088,832 shares of common stock remain available for grant under the 1990 Plan.

The 1990 Plan is administered by the compensation committee of the Company s Board of Directors (the Board). Subject to the terms of the 1990 Plan, the Board has the authority to determine plan participants, the types and amounts of awards to be granted and the terms, conditions and provisions of awards. Options granted pursuant to the 1990 Plan may, at the discretion of the Board, be either incentive stock options or non-qualified stock options. The exercise price of incentive stock options may not be less than the fair market value of the common stock on the date of grant and the term of the option may not exceed 10 years. In the case of non-qualified stock options, the exercise price may not be less than 85 percent of the fair market value of the common stock on the date of grant. Any stock appreciation rights granted under the 1990 Plan will give the holder the right to receive cash in an amount equal to the difference between the fair market value of the share of common stock on the date of exercise and the exercise price. Restricted stock under the 1990 Plan will generally consist of shares which may not be disposed of by participants until certain restrictions established by the Board lapse. Restricted stock rights under the 1990 Plan will generally represent the right to receive shares of common stock when certain restrictions established by the Board lapse.

Under the Non-Management Director Stock Option Plan (the Director Plan), 60,000 shares of common stock were available for issuance to the outside directors of the Company. As of December 31, 2003, options for a total of 51,000 shares of common stock had been granted under the Director Plan. Options granted pursuant to the Director Plan are non-qualified stock options with terms of 10 years and an option exercise price equal to the fair market value of the common stock on the date of grant. Under the terms of the Director Plan, no additional options can be granted under this plan.

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The following is an analysis of all option activity under the 1990 Plan and the Director Plan for 2003, 2002 and 2001:

	Years Ended December 31,					
	2003		2002		2001	
	Shares	Wtd. Avg. Exercise Price	Shares	Wtd. Avg. Exercise Price	Shares	Wtd. Avg. Exercise Price
Beginning stock options outstanding	5,440,736	$ 14.42	5,715,186	$ 14.57	5,026,592	$ 13.16
Stock options granted	55,000	10.19	77,000	11.47	1,038,000	20.87
Stock options canceled	(2,333,500)	19.96	(270,450)	18.94	(179,500)	18.53
Stock options exercised	(176,300)	8.30	(81,000)	7.31	(169,906)	7.24
Ending stock options outstanding	2,985,936	$ 10.37	5,440,736	$ 14.42	5,715,186	$ 14.57
Ending stock options exercisable	2,878,271	$ 10.30	3,894,071	$ 12.18	2,869,131	$ 13.47
Weighted average SFAS 123 fair value of options granted	$ 3.53		$ 4.80		$ 9.09	

Of the 2,985,936 options outstanding at December 31, 2003: (a) 1,488,822 options have exercise prices between $7.25 and $9.06, with a weighted average exercise price of $7.87 and a weighted average contractual life of 3.3 years (all of these options are currently exercisable); (b) 773,214 options have exercise prices between $9.69 and $12.78, with a weighted average exercise price of $10.06 and a weighted average contractual life of 2.9 years (679,881 of these options are currently exercisable at a weighted average price of $9.97); and (c) 723,900 options have exercise prices between $15.50 and $22.94, with a weighted average exercise price of $15.82 and a weighted average contractual life of 3.3 years (709,568 of these options are currently exercisable at a weighted average exercise price of $15.72).

All of the outstanding options are exercisable at various times in years 2004 through 2012. All incentive stock options and non-qualified stock options were granted at fair market value on the date of grant. Generally, options granted under the 1990 Plan have a 10-year term and provide for vesting over three years.

In addition to the above option activity, the Company has granted restricted stock awards under the 1990 Plan. The restricted stock awards generally vest over a one to three-year period except for 200,000 shares of restricted stock granted in 2003 to certain senior executives of the Company. These restricted shares will vest on the later of one year from the date of grant or when the Company s common stock price has closed at $15.00 per share or higher for 45 consecutive trading days. These restricted shares will be forfeited three years from the date of grant if not vested by that date. The Company will record compensation expense when the stock price criterion has been met. Total restricted stock compensation expense on all other restricted stock awards, net of forfeitures, of $13.6 million (based on the stock price on the date of grant) is being amortized over the vesting periods. During 2003, 2002 and 2001, the Company recorded restricted stock compensation expense of $5.9 million, $1.2 million and $0.5 million, respectively. Restricted stock compensation expense is reduced when non-vested restricted stock awards are forfeited. The following is an analysis of all restricted stock awards under the 1990 Plan for 2003, 2002 and 2001:

	Years Ended December 31,		
	2003	**2002**	**2001**
Beginning restricted stock awards outstanding	390,784	110,000	
Restricted stock awards granted	1,215,303	416,650	110,000
Restricted stock awards canceled	(134,713)	(119,200)	
Restricted stock awards vested	(118,022)	(16,666)	
Ending restricted stock awards outstanding	1,353,352	390,784	110,000

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On February 20, 2003, pursuant to the terms of an offer to exchange, the Company accepted for exchange options to purchase 2,118,000 shares of its common stock (included in the total 2,333,500 stock options canceled in 2003), representing approximately 95.1 percent of the 2,227,500 options that were eligible to be tendered in the offer. The options exchanged had exercise prices ranging from $19.28 to $21.81 per share. In accordance with the terms of the offer to exchange, the Company granted restricted stock and restricted stock rights representing an aggregate of 562,840 shares of its common stock (included in the total 1,215,303 restricted stock awards granted in 2003) in exchange for the tendered options. At December 31, 2003, a total of 5,223,118 shares of the Company s common stock are reserved for issuance pursuant to the 1990 Plan and the Director Plan.

Preferred Stock

Preferred stock at December 31, 2003, consisted of 5,000,000 authorized but unissued shares. Preferred stock may be issued from time to time in one or more series, and the Board, without further approval of the stockholders, is authorized to fix the dividend rates and terms, conversion rights, voting rights, redemption rights and terms, liquidation preferences, sinking fund and any other rights, preferences, privileges and restrictions applicable to each series of preferred stock.

Preferred Share Purchase Rights

On March 16, 1999, the Board adopted a stockholder rights plan and declared a dividend distribution of one Preferred Share Purchase Right (a Right) on each outstanding share of the Company s common stock to stockholders of record on April 5, 1999 (the Record Date). Each common share issued after the Record Date has also been issued a Right. The description and terms of the Rights are set forth in the Rights Agreement dated March 16, 1999, between the Company and the rights agent. The Rights will expire on April 5, 2009.

On April 3, 2002, the Company and the rights agent executed the First Amendment to Rights Agreement (the Amendment). As more fully set forth in the Amendment, the Amendment, among other things, amends the Rights Agreement to lower the threshold at which a person becomes an Acquiring Person (as defined in the Rights Agreement, as amended by the Amendment) and lowers the percentage at which the rights plan is triggered from 15 percent to 10 percent.

The Rights will be exercisable only if a person or group acquires 10 percent or more of the Company s common stock or announces a tender offer, the consummation of which would result in ownership by a person or group of 10 percent or more of the Company s common stock. Each Right will entitle stockholders to buy one one-thousandth of a share of a new series of junior participating preferred stock at an exercise price of $60. If the Company is acquired in a merger or other business combination transaction after a person has acquired 10 percent or more of the Company s outstanding common stock, each Right will entitle its holder to purchase, at the Right s then-current exercise price, a number of the acquiring company s common shares having a market value of twice such price. In addition, if a person or group acquires 10 percent or more of the Company s outstanding common stock, each Right will entitle its holder (other than such person or members of such group) to purchase, at the Right s then-current exercise price, a number of the Company s common shares having a market value of twice such price. Prior to the acquisition by a person or group of beneficial ownership of 10 percent or more of the Company s common stock, the Rights are redeemable for $0.01 per Right at the option of the Board.

Treasury stock

In 2003, certain members of management repaid indebtedness to the Company through cash payments and through the sale of shares of the Company s common stock to the Company at the market price of the Company s common stock on the date of the repayment.

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4. Goodwill

All of the Company s goodwill was related to the Company s Canadian operations, which is consistent with the Canadian segment identified in Note 10 and represents the excess of the purchase price over the estimated fair value of the net assets acquired in the purchase of Genesis in 2001. Effective January 1, 2002, the Company adopted the provisions of SFAS 142. SFAS 142 changed the accounting for goodwill from an amortization method to an impairment assessment only method.

Under the new rule, the Company had a six-month transitional period from the effective date of the adoption to perform an initial assessment of whether there was an indication that the carrying value of goodwill was impaired. This assessment was made by comparing the fair value of the Canadian operations, as determined in accordance with SFAS 142, to its book value. If the fair value was less than the book value, an impairment was indicated and the Company would be required to perform a second test no later than December 31, 2002, to measure the amount of the impairment. Any initial impairment is to be taken as a cumulative effect of change in accounting principle retroactive to January 1, 2002. This assessment is required to be conducted at least annually and any such impairment is required to be recorded as a charge to operating earnings.

The Company completed its initial assessment in the second quarter of 2002 and recorded a non-cash charge of $60.5 million. Decreases in oil and gas price expectations from the May 2, 2001, acquisition of Genesis to January 1, 2002, and certain downward revisions recorded to the Company s Canadian oil and gas reserves at December 31, 2001, were the primary factors that led to the goodwill impairment. The charge was recorded as a cumulative effect of change in accounting principle retroactive to January 1, 2002, in accordance with the provisions of SFAS 142. The Company performed assessments of goodwill for impairment as of December 31, 2003 and 2002, and recorded additional non-cash charges of $25.7 million and $76.4 million as an operating expense in 2003 and 2002, respectively. Certain downward revisions recorded to the Company s Canadian oil and gas reserves in the fourth quarters of 2003 and 2002 were the primary factors which led to the additional impairments.

The Company engaged an independent appraisal firm to determine the fair value of its Canadian reporting unit as of January 1, 2002, and December 31, 2002. These fair value determinations were made principally on the basis of present value of future after tax cash flows, although other valuation methods were considered. The book value of the Canadian operations exceeded the fair value determined by the independent appraisal firm, indicating a possible impairment of goodwill. The Company then calculated the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the Canadian operations from the fair value of the Canadian operations determined in step one of the assessment. The carrying value of the goodwill exceeded this calculated implied fair value of the goodwill at January 1, 2002, and at December 31, 2002, resulting in the impairment charges. As a result of the significant impairments of the Company s Canadian oil and gas properties in the fourth quarter of 2003, the Company determined that goodwill was fully impaired at December 31, 2003.

The goodwill of the Company s Canadian operations had no net book value at December 31, 2003, after the impairments. The Company has no other intangible assets at December 31, 2003. The changes in the carrying amount of goodwill for the years ended December 31, 2003 and 2002, were as follows (in thousands):

December 31, 2001	$ 156,990
Impairments	(136,898)
Change in foreign currency exchange rate	1,007
December 31, 2002	21,099
Impairments	(25,673)
Change in foreign currency exchange rate	4,574
December 31, 2003	$

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The results of operations presented below for the year ended December 31, 2001, reflect the operations of the Company had the Company adopted the non-amortization provisions of SFAS 142 effective January 1, 2001 (in thousands, except per share amounts):

Reported net income	$ 133,507
Goodwill amortization	11,940
Adjusted net income	$ 145,447
Adjusted basic income per share	$ 2.31
Adjusted diluted income per share	$ 2.27

5. Commitments and Contingencies

The Company had $1.1 million in letters of credit outstanding at December 31, 2003. These letters of credit relate primarily to bonding requirements of various state regulatory agencies in the U.S. for oil and gas operations. The Company s availability under its revolving credit facility is reduced by the outstanding letters of credit.

Rent expense was $3.9 million, $3.5 million and $2.9 million for 2003, 2002 and 2001, respectively. The future minimum commitments under long-term, non-cancellable leases for office space are $3.6 million, $2.9 million, $1.4 million, $1.2 million and $0.4 million for the years 2004 through 2008 respectively.

The Company has entered into certain firm gas transportation and compression agreements in Canada and 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. The Company paid $5.1 million, $5.8 million and $4.9 million under these agreements in 2003, 2002 and 2001, respectively. Based on the current fee level, these commitments total approximately $3.0 million in 2004, $1.8 million in 2005, $1.6 million in 2006, $0.4 million in 2007 and $0.3 million in each of the years 2008 and 2009.

The Company has future minimum long-term electric power purchase commitments in Argentina of $3.5 million in 2004, $3.5 million in 2005, $3.5 million in 2006 and $4.8 million in 2007. No amounts have been paid under these agreements through December 31, 2003.

In Canada, the Company has entered into certain firm gas gathering and processing agreements whereby it has committed to process certain volumes of gas at a monthly capital fee based on a sliding scale and to pay its proportionate share of the plant operating costs based on the Company s share of the total volumes processed through the plant. The Company paid $0.2 million, $0.3 million and $0.3 million under these agreements in 2003, 2002 and 2001, respectively. The future volumes under these agreements total 2.3 MMcf per day in 2004 and 2.0 MMcf per day for the first six months of 2005.

The Company has also entered into deliver-or-pay arrangements where it 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 the Company currently expects to produce sufficient volumes to satisfy all of its deliver-or-pay obligations. The volumes contracted under the agreement in Bolivia are 10.3 Bcf in 2004, 6.0 Bcf in 2005, 5.8 Bcf in 2006, 6.0 Bcf in 2007, 6.9 Bcf in 2008 and 6.9 Bcf in 2009. The volumes contracted under the agreement in Argentina are 5.8 Bcf in 2004, 3.8 Bcf in 2005, 3.3 Bcf in 2006, 3.6 Bcf in 2007 and 3.9 Bcf in 2008. The Company made no payments under these agreements in 2003, 2002 or 2001.

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Under the terms of the Company s concession agreement in Yemen, the Company is required to make annual payments of $337,500 throughout the 20 year term of the agreement, which was granted in October 2003.

The Company is a named defendant in various lawsuits and is a party in governmental proceedings from time to time arising in the ordinary course of business. In the opinion of management, none of the various pending lawsuits and proceedings should have a material adverse impact on the Company s financial position or results of operations.

6. Financial Instruments

Price Risk Management

The Company periodically uses derivative financial instruments as hedges to reduce the impact of oil and gas price fluctuations on its operating results and cash flows. These hedging agreements typically entitle the Company to receive payments from (or require it to make payments to) the counterparties based upon the differential between a fixed price and a floating price based on a published index. The Company s hedging activities are conducted with investment and commercial banks which the Company believes are minimal credit risks. The Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price risks. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

The Company participated in oil hedges covering 4.9 million barrels and gas hedges covering 20.1 million MMBtu (millions of British thermal units) in 2003. At December 31, 2003, the Company was a party to oil price swap agreements for various periods of 2004 and 2005 covering 5.0 million barrels at a weighted average NYMEX reference price of $28.34 per barrel. Subsequent to December 31, 2003, the Company entered into additional oil hedging contracts for various periods in 2004 covering an additional 1.7 million barrels of oil at a weighted average NYMEX reference price of $30.05 per barrel. In total, the Company has entered into oil hedging contracts covering 2004 and 2005 oil production of 6.7 million barrels at a weighted average NYMEX reference price of $28.77 per barrel. The Company continues to monitor oil and gas prices and may enter into additional oil and gas hedges or swaps in the future.

Fair Value of Financial Instruments

The Company values financial instruments as required by Statement of Financial Accounting Standards No. 107, *Disclosures About Fair Value of Financial Instruments*. The Company estimates the value of the Notes (see Note 2) based on quoted market prices. The Company estimates the value of its other long-term debt based on the estimated borrowing rates currently available to the Company for long-term loans with similar terms and remaining maturities. The estimated fair value of the Company s long-term debt at December 31, 2003 and 2002, was $749.5 million and $899.5 million, respectively, compared with carrying values of $700.0 million and $883.2 million, respectively.

The fair value of commodity swap agreements is the amount at which they could be settled, based on quoted market prices. At December 31, 2003 and 2002, the Company would have paid approximately $7.9 million and $17.1 million, respectively, to terminate its swap agreements then in place. The carrying value of other financial instruments approximates fair value because of the short maturity of those instruments.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

7. Income Taxes

Income (loss) from continuing operations before income taxes and cumulative effect of changes in accounting principles is composed of the following (in thousands):

	Years Ended December 31,		
	2003	**2002**	**2001**
Domestic	$ (6,922)	$ (29,442)	$ 117,240
Foreign	(323,455)	(114,868)	77,534
	$ (330,377)	$ (144,310)	$ 194,774

The total provision (benefit) for income taxes, excluding amounts related to the Company s discontinued operations in Trinidad and Ecuador, consists of the following (in thousands):

	Years Ended December 31,		
	2003	**2002**	**2001**
Current:			
Domestic	$ (8,318)	$ (10,273)	$ 46,486
Foreign	52,191	31,957	34,049
Deferred:			
Domestic	2,512	93	(2,087)
Foreign	(117,892)	(60,865)	(10,123)
	$ (71,507)	$ (39,088)	$ 68,325

A reconciliation of the U.S. federal statutory income tax rate to the effective rate is as follows:

	Years Ended December 31,		
	2003	2002	2001
U.S. federal statutory income tax rate	35.0%	35.0%	35.0%
State income tax	0.1	0.8	2.4
Foreign operations	(2.3)	(8.8)	(1.7)
Canadian deferred tax asset valuation allowance	(10.7)		
U.S. federal income tax credits			(0.8)
Other	(0.5)	0.1	0.2
	21.6%	27.1%	35.1%

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The components of the Company s net deferred tax liability, excluding amounts related to the Company s discontinued operations in Trinidad and Ecuador, as of December 31, 2003 and 2002, are as follows (in thousands):

	December 31,	
	2003	**2002**
Deferred Tax Assets:		
Book-tax differences in property	$ 32,029	$ 12,416
U.S. federal and state net operating loss carryforwards	2,255	1,648
Foreign net operating loss carryforwards	26,619	23,551
Foreign tax credit carryforwards	4,227	2,940
Other temporary book/tax differences	707	652
	65,837	41,207
Less: Valuation allowance	(35,662)	
	30,175	41,207
Deferred Tax Liabilities:		
Book-tax differences in property basis	76,895	163,147
Other temporary book-tax differences	7,582	15,075
	84,477	178,222
Net deferred tax liability	$ 54,302	$ 137,015

The Company generated a U.S. federal regular income tax net operating loss (NOL) in 2002, which it carried back against taxable income in prior years receiving a refund of taxes previously paid. The Company has no U.S. Federal NOL carryforward as of December 31, 2003; however, the Company does have various state NOL carryforwards which have varying lengths of allowable carryforward periods ranging from five to 20 years and can be used to offset future state taxable income.

Earnings of the Company s foreign subsidiaries are subject to foreign income taxes. No U.S. deferred tax liability will be recognized related to the unremitted earnings of these foreign subsidiaries, as it is the Company s intention, generally, to reinvest such earnings permanently. The Company recorded additional U.S. income taxes of $37.7 million in 2003 related to the repatriation of previously untaxed foreign earnings as a result of the sale of its interest in Ecuador in January 2003. The estimated amount of unrecognized deferred tax liability related to these unremitted earnings of foreign subsidiaries as of December 31, 2003, was approximately $130 million.

The Company has a Bolivian income tax NOL carryforward of approximately $47.0 million that does not expire. Additionally, the Company has a Canadian income tax NOL carryforward of approximately C$48.7 million ($37.6 million), approximately 26 percent of which will expire in 2008 with the balance expiring in 2009. The Company has also incurred approximately $51.3 million related to its Yemen operations that it expects to recover under the cost recovery provisions of its production sharing agreement with the government of Yemen. These provisions allow the Company to annually offset a portion of its revenues that would otherwise be taxable with costs previously incurred in Yemen until such costs have been fully recovered. The Company expects to recover this amount over the next five years.

As a result of the impairment to the Company s book value for its Canadian oil and gas properties due to the significant reduction in the Company s Canadian reserves and estimated future net revenues associated with these reserves, the Company s tax basis in its Canadian properties exceeded its book basis at December 31, 2003. This excess tax basis, along with the Canadian income tax NOL, resulted in a net deferred tax asset for Canada at December 31, 2003. The Company evaluated the likelihood of the recoverability of this Canadian deferred tax asset based on current projections of future taxable income and determined this likelihood to be remote. Therefore, it has placed a valuation allowance against its entire Canadian deferred tax asset of $35.7 million. This valuation allowance will be evaluated in the future to determine if changes in facts and circumstances warrant a change to the valuation allowance.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

8. Significant Acquisition

On May 2, 2001, the Company completed the acquisition of Canadian-based Genesis for total consideration of $617 million, including transaction costs and the assumption of the estimated net indebtedness of Genesis at closing (the Genesis Acquisition). The cash portion of the acquisition price was paid through advances under the Company s revolving credit facility and cash on hand. The Genesis Acquisition was accounted for using purchase accounting and, as such, only eight months of Genesis activity are included in the Company s statement of operations for the year ended December 31, 2001. As part of the purchase price allocation, the Company recorded $175.5 million of goodwill.

If the Genesis Acquisition had been consummated as of January 1, 2001, the Company s unaudited pro forma revenues and net income for the year ended December 31, 2001, would have been as shown below; however, such pro forma information is not necessarily indicative of what actually would have occurred had the transaction occurred on such date (in thousands, except per share amounts).

	Year Ended December 31, 2001	
Revenues	$	943,756
Income from continuing operations before cumulative effect of change in accounting principle		124,059
Net income		131,117
Basic Income Per Share:		
Income from continuing operations before cumulative effect of change in accounting principle	$	1.97
Net income		2.08
Diluted Income Per Share:		
Income from continuing operations before cumulative effect of change in accounting principle	$	1.94
Net income		2.05

9. Discontinued Operations

On July 30, 2002, the Company completed the sale of its operations in Trinidad. The Company received $40 million in cash and recorded a gain of approximately $31.9 million ($14.9 million after income taxes). On January 31, 2003, the Company completed the sale of its operations in Ecuador. The Company received $137.4 million in cash and recorded a gain of approximately $47.3 million ($9.5 million after income taxes).

In accordance with the rules established by SFAS 144, the Company s operations in Trinidad and Ecuador, along with the gains on the sales of the operations in Trinidad and Ecuador are accounted for as discontinued operations in the accompanying consolidated financial statements.

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Following is summarized financial information for the Company s operations in Trinidad (in thousands):

	Years Ended December 31,	
	2002	**2001**
Revenues	$	$ 27
Loss from discontinued operations	$ (711)	$ (980)
Deferred tax benefit	(253)	(343)
Net operating loss from discontinued operations	(458)	(637)
Gain on sale of operations in Trinidad, net of $16,939 income tax expense	14,943	
Income (loss) from discontinued operations, net of tax	$ 14,485	$ (637)

Following is summarized financial information for the Company s operations in Ecuador (in thousands):

	Years Ended December 31,		
	2003	**2002**	**2001**
Revenues	$ 50,341	$ 24,153	$ 24,521
Income from discontinued operations	$ 1,812	$ 10,113	$ 10,186
Deferred tax expense	459	2,493	2,491
Net operating income from discontinued operations	1,353	7,620	7,695
Gain on sale of operations in Ecuador, net of $37,766 income tax expense	9,491		
Income from discontinued operations, net of tax	$ 10,844	$ 7,620	$ 7,695

	December 31, 2002

Current assets	$ 19,365
Property, plant and equipment, net	58,968
Other assets, net	2,676
Deferred income tax asset	5,165
Assets of discontinued operations	$ 86,174
Current liabilities of discontinued operations	$ 10,769

The income tax expense related to the gain on the sale of the Company s operations in Ecuador includes $19.4 million of taxes on previously unremitted foreign earnings. No U.S. income taxes were previously recorded on these earnings. In accordance with SFAS 144, the assets of the Company s operations in Ecuador were reclassified as Assets of discontinued operations and the liabilities were reclassified as Liabilities of discontinued operations in the accompanying consolidated balance sheets as of December 31, 2002.

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10. Segment Information

The Company applies Statement of Financial Accounting Standards No. 131, *Disclosures About Segments of an Enterprise and Related Information.* The Company s reportable business segments have been identified based on the differences in products or services provided. Revenues for the exploration and production segment are derived from the production and sale of gas and crude oil. Revenues for the gathering/plant segment arise from the processing, transportation and sale of gas and crude oil. The gas marketing segment generates revenue by earning fees through the marketing of Company-produced gas volumes and the purchase and resale of third party-produced gas volumes. The Company evaluates the performance of its operating segments based on operating income.

Operations in the gathering/plant and gas marketing industries are in the United States. The Company operates in the oil and gas exploration and production industry in the United States, Canada, South America, Yemen, Italy and Bulgaria. The financial information related to the Company s discontinued operations in Trinidad and Ecuador has been excluded for all periods presented (see Note 9), except for total assets at the end of each period. Summarized financial information for the Company s reportable segments is shown on the following pages.

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	Exploration and Production				
2003 (in thousands)	**U.S.**	**Canada**	**Argentina**	**Bolivia**	**Other Foreign**
External segment revenues	$ 252,313	$ 119,118	$ 269,555	$ 14,475	$
Intersegment revenues					
Depreciation, depletion and amortization expense	38,215	55,468	43,518	2,815	
Impairment of proved oil and gas properties	6,049	364,195			
Impairment of goodwill		25,673			
Operating income (loss)	105,011	(425,849)	138,171	6,014	(6,516)
Total assets	463,170	218,917	538,512	117,724	25,388
Capital investments	74,460	31,335	58,332	1,653	14,906
Long-lived assets	434,219	176,427	491,122	91,438	24,672

2003 (in thousands)	**Gathering/ Plant**	**Gas Marketing**	**Corporate**	**Total**
External segment revenues	$ 8,089	$ 98,451	$ (5,674)	$ 756,327
Intersegment revenues		1,199		1,199
Depreciation, depletion and amortization expense	1,258		2,421	143,695
Impairment of proved oil and gas properties				370,244
Impairment of goodwill				25,673
Operating income (loss)	(2,029)	2,595	(63,829)	(246,432)
Total assets	11,687	11,858	59,582	1,446,838
Capital investments	2,484		1,789	184,959
Long-lived assets	9,573		6,443	1,233,894

	Exploration and Production				
2002 (in thousands)	**U.S.**	**Canada**	**Argentina**	**Bolivia**	**Other Foreign**
External segment revenues	$ 236,005	$ 113,959	$ 233,057	$ 12,344	$
Intersegment revenues					
Depreciation, depletion and amortization expense	51,026	73,550	46,067	3,564	
Impairment of proved oil and gas properties	16,972	81,748			
Impairment of goodwill		136,898			
Operating income (loss)	64,532	(244,471)	119,309	4,286	(12,262)
Total assets	418,314	573,960	497,738	119,239	16,674
Capital investments	29,487	58,632	19,008	2,625	7,785
Long-lived assets	387,412	548,977	449,010	92,585	15,985

2002 (in thousands)	Gathering/ Plant	Gas Marketing	Corporate	Total
External segment revenues	$ 5,731	$ 66,517	$ (3,350)	$ 664,263
Intersegment revenues		902		902
Depreciation, depletion and amortization expense	1,687		3,008	178,902
Impairment of proved oil and gas properties				98,720
Impairment of goodwill				136,898
Operating income (loss)	(3,457)	1,610	(48,536)	(118,989)
Total assets	10,474	11,260	128,145	1,775,804
Capital investments	4,554		1,263	123,354
Long-lived assets	8,074		6,029	1,508,072

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	Exploration and Production				
2001 (in thousands)	**U.S.**	**Canada**	**Argentina**	**Bolivia**	**Other Foreign**
External segment revenues	$ 386,344	$ 87,922	$ 245,627	$ 17,648	$
Intersegment revenues					
Depreciation, depletion and amortization expense	60,426	52,072	44,252	5,032	
Impairment of proved oil and gas properties	9,555	18,895	600		
Operating income (loss)	191,917	(34,007)	137,473	8,039	(3,153)
Total assets	477,415	818,564	530,201	119,655	21,263
Capital investments	61,821	689,308	119,105	1,030	3,073
Long-lived assets	436,327	795,000	475,418	93,572	20,462

2001 (in thousands)	**Gathering/ Plant**	**Gas Marketing**	**Corporate**	**Total**
External segment revenues	$ 17,032	$ 130,209	$ 185	$ 884,967
Intersegment revenues		1,968		1,968
Depreciation, depletion and amortization expense	1,326		2,876	165,984
Impairment of proved oil and gas properties				29,050
Operating income (loss)	(2,053)	3,836	(42,558)	259,494
Total assets	8,456	8,459	123,889	2,107,902
Capital investments	1,256		5,870	881,463
Long-lived assets	5,798		7,745	1,834,322

Intersegment sales are priced in accordance with terms of existing contracts and current market conditions. Capital investments include expensed exploratory costs. Long-lived assets include property, plant and equipment and goodwill. Interest costs and the loss on early extinguishment of debt are not allocated to segments. General and administrative expense and stock compensation are included in the Corporate segment, except for certain operating expenses related to oil and gas producing activities, which are allocated to each Exploration and Production segment. Operating income (loss) includes the cumulative effect of changes in accounting principles, net of tax.

During 2003, sales to one crude oil purchaser of the exploration and production segment represented approximately 16 percent of the Company s total revenues (exclusive of eliminations of intersegment sales, the impact of hedges and $1.7 million of losses on the sale of oil and gas properties). During 2002, sales to two crude oil purchasers of the exploration and production segment represented approximately 24 percent and 10 percent, respectively, of the Company s total revenues (exclusive of eliminations of intersegment sales, the impact of hedges and $48.4 million of gains on the sale of oil and gas properties). During 2001, sales to two crude oil purchasers of the exploration and production segment represented approximately 16 percent and 14 percent, respectively, of the Company s total revenues (exclusive of eliminations of intersegment sales and the impact of hedges).

11. Detail of Other Payables and Accrued Liabilities

(In thousands)	December 31, 2003	December 31, 2002
Accrued production costs and production taxes	$ 14,585	$ 12,874
Accrued oil and gas capital expenditures	14,232	9,145
Accrued interest payable	10,338	16,462
Current liability for asset retirement obligations	5,810	
Other	25,063	20,532
	$ 70,028	$ 59,013

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

12. Quarterly Results (Unaudited)

The following is a summary of the quarterly results of operations for the years ended December 31, 2003 and 2002. All of the quarters for 2003 and 2002 have been restated to exclude the Company s discontinued operations in Trinidad and Ecuador, except income (loss) before cumulative effect of change in accounting principle and net income (loss) and the respective per share amounts (see Note 9).

(In thousands, except per share amounts)	Quarter Ended			
	Mar. 31	Jun. 30	Sept. 30	Dec. 31
2003				
Revenues and other income (expense)	$ 215,997	$ 186,812	$ 183,356	$ 170,162
Operating income (loss)	59,628	6,810 [c,d]	39,974	(359,963)[b,c]
Provision (benefit) for income taxes	16,943	(2,519)[c,d]	10,382	(96,313)[c]
Income (loss) before cumulative effect of change in accounting principle	33,562	(8,687)[c,d]	11,755	(284,656)[b,c]
Net income (loss)	40,681	(8,687)[c,d]	11,755	(284,656)[b,c]
Income (loss) before cumulative effect of change in accounting principle per share:				
Basic	0.52	(0.14)[c,d]	0.18	(4.43)[b,c]
Diluted	0.52	(0.14)[c,d]	0.18	(4.43)[b,c]
Net income (loss) per share:				
Basic	0.63	(0.14)[c,d]	0.18	(4.43)[b,c]
Diluted	0.63	(0.14)[c,d]	0.18	(4.43)[b,c]
2002				
Revenues and other income (expense)	$ 135,806	$ 190,955	$ 166,880	$ 170,622
Operating income (loss)	4,662	52,982	39,008	(155,094)[b,c]
Provision (benefit) for income taxes	(6,479)	3,264	4,223	(40,096)[c]
Income (loss) before cumulative effect of change in accounting principle	(5,620)	22,429	31,695	(131,621)[b,c]
Net income (loss)	(66,167)[a]	22,429	31,695	(131,621)[b,c]
Income (loss) before cumulative effect of change in accounting principle per share:				
Basic	(0.09)	0.36	0.50	(2.08)[b,c]
Diluted	(0.09)	0.35	0.50	(2.08)[b,c]
Net income (loss) per share:				
Basic	(1.05)[a]	0.36	0.50	(2.08)[b,c]
Diluted	(1.05)[a]	0.35	0.50	(2.08)[b,c]

(a) Net loss for the quarter ended March 31, 2002, includes the cumulative effect of a change in accounting principle, net of tax, of $60.5 million, or $0.96 per share.

(b) The quarters ended December 31, 2003 and 2002, include goodwill impairments of $25.7 million (or $0.40 per share) and $76.4 million (or $1.21 per share), respectively.

(c) The quarters ended June 30, 2003, December 31, 2003 and December 31, 2002, include impairment of proved oil and gas properties of $12.6 million ($7.3 million net of tax, or $0.11 per share), $356.2 million ($269.4 million net of tax, or $4.20 per share) and $98.7 million ($57.7 million net of tax, or $0.91 per share), respectively.

(d) The quarter ended June 30, 2003, includes exploration costs of $23.7 million ($13.9 million net of tax, or $0.22 per share) to fully impair the Company s undeveloped leaseholds in the Northwest Territories.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

13. Supplementary Financial Information for Oil and Gas Producing Activities

Results of Operations from Oil and Gas Producing Activities

The following sets forth certain information with respect to the Company s results of operations from oil and gas producing activities for the years ended December 31, 2003, 2002 and 2001. The results of operations related to the Company s discontinued operations in Trinidad and Ecuador have been excluded for all periods presented (see Note 9).

	2003						
(In thousands)	U.S.	Canada	Argentina	Bolivia	Yemen	Other	Total
Revenues	$ 253,507	$ 119,078	$ 276,131	$ 14,475	$	$	$ 663,191
Production and operating costs	96,677	41,007	84,961	4,608			227,253
Exploration costs	13,805	53,325		1,286	4,739	1,777	74,932
Impairment of proved properties	6,049	364,195					370,244
Depreciation, depletion and amortization	38,215	55,468	43,518	2,815			140,016
Accretion	3,463	1,360	2,421	96			7,340
Results of operations before income taxes	95,298	(396,277)	145,231	5,670	(4,739)	(1,777)	(156,594)
Income tax expense (benefit)	37,071	(103,430)	56,074	1,418	(1,659)	(622)	(11,148)
Results of operations (excluding corporate overhead and interest costs)	$ 58,227	$ (292,847)	$ 89,157	$ 4,252	$ (3,080)	$ (1,155)	$ (145,446)

	2002						
(In thousands)	U.S.	Canada	Argentina	Bolivia	Yemen	Other	Total
Revenues	$ 219,511	$ 113,808	$ 232,787	$ 12,344	$	$	$ 578,450
Production and operating costs	92,795	46,441	67,681	4,494			211,411
Exploration costs	10,679	19,792			12,215	48	42,734
Impairment of proved properties	16,972	81,748					98,720
Depreciation, depletion and amortization	51,026	73,550	46,067	3,564			174,207
Results of operations before income taxes	48,039	(107,723)	119,039	4,286	(12,215)	(48)	51,378
Income tax expense (benefit)	18,687	(45,373)	34,908	1,072	(4,275)	(17)	5,002

Results of operations (excluding corporate overhead and interest costs)	$ 29,352	$ (62,350)	$ 84,131	$ 3,214	$ (7,940)	$ (31)	$ 46,376

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	2001						
(In thousands)	U.S.	Canada	Argentina	Bolivia	Yemen	Other	Total
Revenues	$ 359,471	$ 86,277	$ 243,329	$ 17,648	$	$	$ 706,725
Production and operating costs	111,657	33,377	63,300	4,575			212,909
Exploration costs	12,789	5,645			2,837	316	21,587
Impairment of proved properties	9,555	18,895	600				29,050
Depreciation, depletion and amortization	60,426	52,072	44,252	5,033			161,783
Results of operations before income taxes	165,044	(23,712)	135,177	8,040	(2,837)	(316)	281,396
Income tax expense (benefit)	64,202	(8,399)	40,553	2,010	(993)	(111)	97,262
Results of operations (excluding corporate overhead and interest costs)	$ 100,842	$ (15,313)	$ 94,624	$ 6,030	$ (1,844)	$ (205)	$ 184,134

Capitalized Costs and Costs Incurred Relating to Oil and Gas Producing Activities

The capitalized costs and costs incurred related to the Company s discontinued operations in Trinidad and Ecuador have been excluded for all periods presented (see Note 9). The Company s net investment in oil and gas properties at December 31, 2003 and 2002, was as follows:

	2003						
(In thousands)	U.S.	Canada	Argentina	Bolivia	Yemen	Other	Total
Unproved properties not being amortized	$ 16,832	$ 29,658	$	$	$ 11,756	$	$ 58,246
Proved properties being amortized	928,612	851,948	747,607	117,864	11,872	1,044	2,658,947
Total capitalized costs	945,444	881,606	747,607	117,864	23,628	1,044	2,717,193
Less accumulated depreciation, depletion and amortization	514,913	705,179	256,485	26,426			1,503,003
Net capitalized costs	$ 430,531	$ 176,427	$ 491,122	$ 91,438	$ 23,628	$ 1,044	$ 1,214,190

2002

(In thousands)	U.S.	Canada	Argentina	Bolivia	Yemen	Other	Total
Unproved properties not being amortized	$ 15,826	$ 56,254	$	$	$ 15,896	$	$ 87,976
Proved properties being amortized	913,056	697,534	671,643	117,054		286	2,399,573
Total capitalized costs	928,882	753,788	671,643	117,054	15,896	286	2,487,549
Less accumulated depreciation, depletion and amortization	545,571	225,909	222,830	24,469			1,018,779
Net capitalized costs	$ 383,311	$ 527,879	$ 448,813	$ 92,585	$ 15,896	$ 286	$ 1,468,770

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Net capitalized costs for the Company s discontinued operations in Ecuador as of December 31, 2002, were approximately $58.9 million.

The following sets forth certain information with respect to costs incurred (exclusive of general support facilities) in the Company s oil and gas activities during 2003, 2002 and 2001:

	2003						
(In thousands)	**U.S.**	**Canada**	**Argentina**	**Bolivia**	**Yemen**	**Other**	**Total**
Acquisitions:							
Unproved properties	$ 3,822	$ 3,919	$	$	$	$ 78	$ 7,819
Proved properties	463						463
Exploratory	21,866	14,211		1,286	12,370	2,458	52,191
Development	48,309	13,205	58,332	367			120,213
	74,460	31,335	58,332	1,653	12,370	2,536	180,686
Asset retirement obligations:							
Wells drilled	765	562	362		99		1,788
Changes in estimates	4,170	2,197	37	(250)			6,154
	4,935	2,759	399	(250)	99		7,942
Total costs incurred	$ 79,395	$ 34,094	$ 58,731	$ 1,403	$ 12,469	$ 2,536	$ 188,628

	2002						
(In thousands)	**U.S.**	**Canada**	**Argentina**	**Bolivia**	**Yemen**	**Other**	**Total**
Acquisitions:							
Unproved properties	$ 1,981	$ 2,690	$	$	$ 338	$ 52	$ 5,061
Proved properties							
Exploratory	15,748	21,872			7,348	47	45,015
Development	11,758	34,070	19,008	2,625			67,461
Total costs incurred	$ 29,487	$ 58,632	$ 19,008	$ 2,625	$ 7,686	$ 99	$ 117,537

	2001						
(In thousands)	U.S.	Canada	Argentina	Bolivia	Yemen	Other	Total
Acquisitions:							
Unproved properties	$ 1,455	$ 59,033	$	$	$ 338	$	$ 60,826
Proved properties	2,506	562,444	42,267				607,217
Exploratory	20,963	24,839			2,385	315	48,502
Development	36,897	42,992	76,838	1,030		35	157,792
Total costs incurred	$ 61,821	$ 689,308	$ 119,105	$ 1,030	$ 2,723	$ 350	$ 874,337

Costs incurred for the Company s discontinued operations in Ecuador for 2003, 2002 and 2001, were approximately $1.1 million, $12.2 million and $11.4 million, respectively. Costs incurred for the Company s discontinued operations in Trinidad for 2001 were $5.7 million.

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Estimated Quantities of Proved Oil and Gas Reserves (Unaudited)

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. The following is an analysis of the Company s proved oil and gas reserves located in the United States, Argentina, Yemen, Ecuador and Trinidad as estimated by the independent petroleum consultants of Netherland, Sewell & Associates, Inc., in Bolivia as estimated by the independent petroleum consultants of DeGolyer and MacNaughton and in Canada as estimated by the independent petroleum consultants of Outtrim Szabo Associates Ltd.

	Oil (MBbls)							
	U.S.	**Canada**	**Argentina**	**Bolivia**	**Yemen**	**Ecuador**	**Trinidad**	**Total**
Proved reserves at December 31, 2000	102,336	2,388	157,536	6,825		49,475		318,560
Revisions of previous estimates	(11,727)	(8,719)	16,899	(589)		2,257		(1,879)
Extensions, discoveries and other additions	487	2,185	216				1,188	4,076
Production	(8,409)	(1,539)	(10,548)	(101)		(1,375)	(2)	(21,974)
Purchase of reserves-in-place		27,493	11,724					39,217
Sales of reserves-in-place	(5,739)							(5,739)
Proved reserves at December 31, 2001	76,948	21,808	175,827	6,135		50,357	1,186	332,261
Revisions of previous estimates	15,498	(1,936)	12,413	47		(4,121)		21,901
Extensions, discoveries and other additions	4,896	447	12,096			382		17,821
Production	(6,796)	(1,829)	(10,942)	(118)		(1,174)		(20,859)
Purchase of reserves-in-place								
Sales of reserves-in-place	(1,241)						(1,186)	(2,427)
Proved reserves at December 31, 2002	89,305	18,490	189,394	6,064		45,444		348,697
Revisions of previous estimates	(15)	(13,296)	4,567	62				(8,682)
Extensions, discoveries and other additions	4,709	302	8,945		3,137			17,093
Production	(6,199)	(1,248)	(10,388)	(83)		(114)		(18,032)
Purchase of reserves-in-place	90							90
Sales of reserves-in-place	(286)	(752)				(45,330)		(46,368)
Proved reserves at December 31, 2003	87,604	3,496	192,518	6,043	3,137			292,798
Proved developed oil reserves at:								
December 31, 2001	66,656	13,259	101,145	4,670		6,054	545	192,329

December 31, 2002	75,547	10,620	106,135	4,721		8,302		205,325
December 31, 2003	75,545	3,462	103,973	5,632				188,612

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	Gas (MMcf)						Total
	U.S.	Canada	Argentina	Bolivia	Trinidad	Total	(MBOE)
Proved reserves at December 31, 2000	398,672	39,478	121,199	463,859		1,023,208	489,095
Revisions of previous estimates	(16,640)	(21,092)	18,768	4,889		(14,075)	(4,225)
Extensions, discoveries and other additions	5,045	32,157	44		64,409	101,655	21,018
Production	(34,168)	(22,132)	(10,253)	(9,088)		(75,641)	(34,581)
Purchase of reserves-in-place		207,701	1,636			209,337	74,107
Sales of reserves-in-place	(27,760)					(27,760)	(10,366)
Proved reserves at December 31, 2001	325,149	236,112	131,394	459,660	64,409	1,216,724	535,048
Revisions of previous estimates	9,367	(37,750)	1	814		(27,568)	17,307
Extensions, discoveries and other additions	9,243	14,614	5,399			29,256	22,697
Production	(24,841)	(29,951)	(8,630)	(6,424)		(69,846)	(32,500)
Purchase of reserves-in-place							
Sales of reserves-in-place	(611)				(64,409)	(65,020)	(13,264)
Proved reserves at December 31, 2002	318,307	183,025	128,164	454,050		1,083,546	529,288
Revisions of previous estimates	3,533	(82,506)	(477)	685		(78,765)	(21,810)
Extensions, discoveries and other additions	24,545	2,410	5,438			32,393	22,492
Production	(23,097)	(19,153)	(9,838)	(6,252)		(58,340)	(27,755)
Purchase of reserves-in-place	258					258	133
Sales of reserves-in-place	(36,015)	(17,039)				(53,054)	(55,210)
Proved reserves at December 31, 2003	287,531	66,737	123,287	448,483		926,038	447,138
Proved developed gas reserves at:							
December 31, 2001	252,062	206,539	48,689	346,148	25,085	878,523	338,750
December 31, 2002	245,854	161,200	43,736	353,259		804,049	339,333
December 31, 2003	228,435	66,433	35,645	384,393		714,906	307,763

Proved reserves at December 31, 2003, 2002, 2001 and 2000, include 46.0 MBbls of oil and 13.3 Bcf of gas (48.2 MMBOE), 41.6 MBbls of oil and 10.5 Bcf of gas (43.3 MMBOE), 26.2 MBbls of oil and 4.6 Bcf of gas (27.0 MMBOE), and 19.2 MBbls of oil and 1.2 Bcf of gas (19.4 MMBOE), respectively, related to the 10 year extension periods contained in the Company s Argentina concession agreements. Upon approval by the government, the extension periods begin in 2015 through 2017, depending on the effective date each concession agreement was granted. We believe, based on historical precedent, that such extensions will be obtained as a matter of course.

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

The Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Standardized Measure) is a disclosure requirement under Statement of Financial Accounting Standards No. 69, *Disclosures about Oil and Gas Producing Activities*. The Standardized Measure does not purport to present the fair market value of proved oil and gas reserves. This would require consideration of expected future economic and operating conditions which are not taken into account in calculating the Standardized Measure.

Under the Standardized Measure, future cash inflows were estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows were reduced by estimated future production, development and abandonment costs based on year-end costs to determine pre-tax cash inflows. Future production costs include the effect of the Argentine oil export tax discussed in Note 1. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the Company s tax basis in the associated proved oil and gas properties. Tax credits and permanent differences were also considered in the future income tax calculation. Future net cash inflows after income taxes were discounted using a 10 percent annual discount rate to arrive at the Standardized Measure.

Set forth below is the Standardized Measure relating to proved oil and gas reserves at December 31, 2003 and 2002 (in thousands):

	2003					
	U.S.	Canada	Argentina	Bolivia	Yemen	Total
Future cash inflows	$ 4,239,048	$ 456,145	$ 5,353,246	$ 498,065	$ 101,069	$ 10,647,573
Future production costs	1,561,174	167,115	1,427,478	57,997	28,643	3,242,407
Future development and abandonment costs	280,585	2,425	434,127	62,163	38,142	817,442
Future net cash inflows before income tax expense	2,397,289	286,605	3,491,641	377,905	34,284	6,587,724
Future income tax expense	835,749		1,183,049	80,578	10,728	2,110,104
Future net cash flows	1,561,540	286,605	2,308,592	297,327	23,556	4,477,620
10 percent annual discount for estimated timing of cash flows	697,421	76,695	1,110,466	201,520	8,990	2,095,092
Standardized Measure of discounted future net cash flows	$ 864,119	$ 209,910	$ 1,198,126	$ 95,807	$ 14,566	$ 2,382,528

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

	2002					
	U.S.	Canada	Argentina	Bolivia	Ecuador	Total
Future cash inflows	$ 3,941,678	$ 1,269,173	$ 5,018,746	$ 507,753	$ 967,509	$ 11,704,859
Future production costs	1,448,897	311,575	1,135,635	59,005	180,476	3,135,588
Future development and abandonment costs	298,454	57,749	393,922	73,425	159,814	983,364
Future net cash inflows before income tax expense	2,194,327	899,849	3,489,189	375,323	627,219	7,585,907
Future income tax expense	747,251	251,847	1,204,976	76,671	131,891	2,412,636
Future net cash flows	1,447,076	648,002	2,284,213	298,652	495,328	5,173,271
10 percent annual discount for estimated timing of cash flows	663,265	233,150	1,139,895	208,239	182,465	2,427,014
Standardized Measure of discounted future net cash flows	$ 783,811	$ 414,852	$ 1,144,318	$ 90,413	$ 312,863	$ 2,746,257

The Standardized Measure at December 31, 2003, 2002 and 2001, includes $92.6 million, $85.6 million and $7.5 million, respectively, related to the 10 year extension periods of the Company s Argentina concession agreements.

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

The following is an analysis of the changes in the Standardized Measure during 2003, 2002 and 2001 (in thousands):

	2003	2002	2001
Standardized Measure - beginning of year	$ 2,746,257	$ 1,438,141	$ 2,951,121
Increases (decreases) -			
Sales, net of production costs	(436,079)	(406,443)	(517,835)
Net change in sales prices, net of production costs	127,952	2,218,644	(2,404,154)
Discoveries and extensions, net of related future development and production costs	233,579	196,774	83,976
Changes in estimated future development costs	(43,111)	13,094	(123,254)
Development costs incurred	118,825	75,186	163,122
Revisions of previous quantity estimates	(282,667)	159,423	(8,646)

Accretion of discount	361,112	190,427	433,862
Net change in income taxes	137,920	(787,133)	911,566
Purchase of reserves-in-place	970		368,552
Sales of reserves-in-place	(508,019)	(11,008)	(141,509)
Timing of production of reserves and other	(74,211)	(340,848)	(278,660)
Standardized Measure-end of year	$ 2,382,528	$ 2,746,257	$ 1,438,141

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INDEX TO EXHIBITS

The following documents are included as exhibits to this Form 10-K. Those exhibits below incorporated by reference herein are indicated as such by the information supplied in the parenthetical thereafter. If no parenthetical appears after an exhibit, such exhibit is filed herewith.

Exhibit Number	Description
3.1	Restated Certificate of Incorporation, as amended, of the Company (Filed as Exhibit 3.2 to the Company s report on Form 10-Q for the quarter ended June 30, 2000, filed August 11, 2000).
3.2	Restated By-laws of the Company (Filed as Exhibit 3.2 to the Company s Registration Statement on Form S-1, Registration No. 33-35289 (the S-1 Registration Statement)).
4.1	Form of stock certificate for Common Stock, par value $0.005 per share (Filed as Exhibit 4.1 to the S-1 Registration Statement).
4.2	Indenture dated as of January 26, 1999, between JPMorgan Chase (formerly The Chase Manhattan Bank), as Trustee, and the Company (Filed as Exhibit 4.4 to the Company s report on Form 10-K for the year ended December 31, 1998, filed March 12, 1999).
4.3	Indenture dated as of May 30, 2001, between JPMorgan Chase (formerly The Chase Manhattan Bank), as Trustee, and the Company (Filed as Exhibit 4.1 to the Company s Registration Statement on Form S-4, Registration No. 333-63896).
4.4	Indenture dated as of May 2, 2002, between JPMorgan Chase Bank, as Trustee, and the Company (Filed as Exhibit 4.1 to the Company s Registration Statement on Form S-4, Registration No. 333-89182).
4.5	Rights Agreement, dated March 16, 1999, between the Company and Mellon Investor Services LLC (formerly ChaseMellon Shareholder Services, L.L.C.), as Rights Agent (Filed as Exhibit 4.1 to the Company s Registration Statement on Form 8-A, filed March 22, 1999).
4.6	First Amendment to Rights Agreement, dated as of April 3, 2002, between the Company and Mellon Investor Services LLC (formerly ChaseMellon Shareholder Services, L.L.C.), as Rights Agent (Filed as Exhibit 4.1 to the Company s Amendment No. 1 to Registration Statement on Form 8-A, filed April 3, 2002).
4.7	Certificate of Designation of Series A Junior Participating Preferred Stock of the Company (Filed as Exhibit 3.3 to the Company s Registration Statement on Form S-3, Registration No. 333-77619).
10.1*	Form of Indemnification Agreement between the Company and certain of its officers and directors (Filed as Exhibit 10.23 to the S-1 Registration Statement).
10.2*	Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 4(d) to the Company s Registration Statement on Form S-8, Registration No. 33-37505).
10.3*	Amendment No. 1 to Vintage Petroleum, Inc. 1990 Stock Plan, effective January 1, 1991 (Filed as Exhibit 10.15 to the Company s report on Form 10-K for the year ended December 31, 1991, filed March 30, 1992).

10.4*	Amendment No. 2 to Vintage Petroleum, Inc. 1990 Stock Plan dated February 24, 1994 (Filed as Exhibit 10.15 to the Company s report on Form 10-K for the year ended December 31, 1993, filed March 29, 1994).
10.5*	Amendment No. 3 to Vintage Petroleum, Inc. 1990 Stock Plan dated March 15, 1996 (Filed as Exhibit A to the Company s Proxy Statement for Annual Meeting of Stockholders dated April 1, 1996).
10.6*	Amendment No. 4 to Vintage Petroleum, Inc. 1990 Stock Plan dated March 11, 1998 (Filed as Exhibit A to the Company s Proxy Statement for Annual Meeting of Stockholders dated March 31, 1998).
10.7*	Amendment No. 5 to Vintage Petroleum, Inc. 1990 Stock Plan dated March 16, 1999 (Filed as Exhibit A to the Company s Proxy Statement for Annual Meeting of Stockholders dated March 31, 1999).
10.8*	Amendment No. 6 to Vintage Petroleum, Inc. 1990 Stock Plan dated March 17, 2000 (Filed as Exhibit A to the Company s Proxy Statement for Annual Meeting of Stockholders dated March 30, 2000).
10.9*	Vintage Petroleum, Inc. Non-Management Director Stock Option Plan (Filed as Exhibit 10.18 to the Company s report on Form 10-K for the year ended December 31, 1992, filed March 31, 1993 (the 1992 Form 10-K)).
10.10*	Form of Incentive Stock Option Agreement under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.20 to the Company s report on Form 10-K for the year ended December 31, 1990, filed April 1, 1991).
10.11*	Form of Non-Qualified Stock Option Agreement under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.20 to the 1992 Form 10-K).
10.12*	Form of Non-Qualified Stock Option Agreement for non-employee directors under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.13 to the Company s report on Form 10-K for the year ended December 31, 1999, filed March 13, 2000).
10.13*	Form of Restricted Stock Award Agreement under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.3 to the Company s report on Form 10-Q for the quarter ended June 30, 2002, filed August 9, 2002).
10.14*	Form of Restricted Stock Rights Award Agreement under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.1 to the Company s report on Form 10-Q for the quarter ended September 30, 2002, filed November 14, 2002).
10.15	Credit Agreement dated as of May 2, 2002, among the Company, as borrower, and certain commercial lending institutions, as lenders, Bank of Montreal, as agent, and the Syndication Agent and Co-Documentation Agents party thereto (Filed as Exhibit 10.1 to the Company s report on Form 10-Q for the quarter ended June 30, 2002, filed August 9, 2002).
10.16	First Amendment to Credit Agreement dated as of May 24, 2002, among the Company, as borrower, the lenders party thereto, Bank of Montreal, as administrative agent, Deutsche Bank Trust Company Americas, as syndication agent, and Fleet National Bank, Societe Generale and The Bank of New York, as co-documentation agents (Filed as Exhibit 10.2 to the Company s report on Form 10-Q for the quarter ended June 30, 2002, filed August 9, 2002).
10.17	Second Amendment to Credit Agreement dated as of May 24, 2002, among the Company, as borrower, the lenders party thereto, Bank of Montreal, as administrative agent, Deutsche Bank Trust Company Americas, as syndication agent, and Fleet National Bank, Societe Generale and The Bank of New York, as co-documentation agents (Filed as Exhibit 10.1 to the Company s report on Form 10-Q for the quarter ended June 30, 2003, filed August 8, 2003).

21.	Subsidiaries of the Company.
23.1	Consent of Ernst & Young LLP.
23.2	Consent of Netherland, Sewell & Associates, Inc.
23.3	Consent of DeGolyer and MacNaughton.
23.4	Consent of Outtrim Szabo Associates Ltd.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) and Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) and Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(b) and Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(b) and Section 906 of the Sarbanes-Oxley Act of 2002.

* Management contract or compensatory plan or arrangement.