2002 Annual Report and Form 10-K



# Navigating
## in Challenging Times



VINTAGE PETROLEUM, INC.

# Vintage Petroleum, Inc. is an independent energy company engaged in the acquisition, development and marketing of and the exploration for crude oil and natural gas.

Vintage's acquisition strategy is to acquire producing properties with significant upside potential at competitive costs. Through development activities, the Vintage staff unlocks the upside potential of acquired properties, increasing production and adding reserves. Vintage also explores for oil and gas through a balanced risk program designed to grow reserves and production in North America in the near term and through a potentially high-impact program targeting areas outside the company's core operations with a longer-term time frame.

## Areas of Operation

Domestic operations are located in the West Coast, Gulf Coast, East Texas and Mid-Continent areas of the United States. South American operations were initiated in 1995 with Vintage's entry into Argentina and have become a significant contributor to reserve and production growth. South American operations have subsequently been expanded to Bolivia. Vintage established Canada as another core area in 2001 with operations in Alberta, British Columbia and Saskatchewan. International exploration efforts are under way in Yemen, the Northwest Territories of Canada and Italy.

## Reserves

Vintage's estimated proved reserves at year-end 2002 were 529 MMBOE, composed of 349 MMBbls of oil accounting for 66 percent of total reserves and 1.1 Tcf of gas accounting for the remaining 34 percent of proved reserves. Proved developed reserves at year-end 2002 comprised 64 percent of total proved reserves.

## Community Commitment

Vintage recognizes that it must be cognizant of people, the communities and cultures in which the company works, its responsibility to the environment and the role each plays in creating shareholder value.

Vintage is committed to involvement in the communities in which it operates and supports various charitable and educational organizations as well as employee volunteerism. This commitment is made in the belief that the company's success is interdependent with the well-being of these communities.

## Value Strategy

The company's proven strategy of acquire, exploit and explore has achieved profitable growth over time. Its seasoned management and experienced operating team are committed to maintaining financial flexibility and building shareholder returns. Vintage is headquartered in Tulsa, Oklahoma, and its common stock has traded on the New York Stock Exchange under the symbol VPI since its initial public offering in 1990. Additional information is available on the company's web site, www.vintagepetroleum.com.

## Glossary

| | |
|---|---|
| BOE | barrels of oil equivalent, using 6 Mcf per barrel ratio |
| MMBOE | million BOE |
| Bcf | billion cubic feet of gas |
| Bcfe | billion cubic feet of gas equivalent using 1 barrel per 6 Mcf ratio |
| Tcf | trillion cubic feet of gas |
| MMBbls | million barrels of oil |
| MMBtu | million British thermal units |
| NYMEX | New York Mercantile Exchange |
| EBITDAX | earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses |

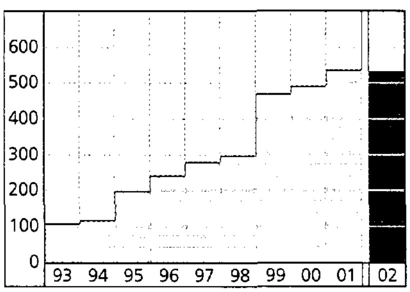
# Highlights

(In thousands except per share amounts or as otherwise indicated)

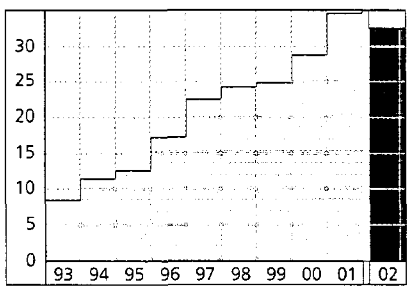
| | 2002 | 2001 | 2000 | 1999 | 1998 |
|---|---|---|---|---|---|
| **Financial Highlights** | | | | | |
| Revenues | $ 664,263 | $ 884,967 | $ 775,380 | $ 492,561 | $ 332,753 |
| Net Income (Loss) | $ (143,664) | $ 133,507 | $ 195,893 | $ 73,371 | $ (87,665) |
| Net Income (Loss) Per Diluted Share | $ (2.27) | $ 2.09 | $ 3.06 | $ 1.24 | $ (1.69) |
| Operating Cash Flow | $ 240,869 | $ 295,685 | $ 395,687 | $ 160,980 | $ 47,767 |
| Weighted Average Common Shares Outstanding – Diluted | 63,219 | 64,027 | 63,963 | 59,315 | 51,900 |
| Total Assets | $1,775,804 | $2,107,902 | $1,352,002 | $1,168,454 | $1,016,472 |
| Long-Term Debt | $ 883,180 | $1,010,673 | $ 464,229 | $ 625,318 | $ 672,507 |
| Stockholders' Equity | $ 570,992 | $ 729,443 | $ 624,857 | $ 431,129 | $ 273,958 |
| Oil and Gas Capital Expenditures: | | | | | |
| Acquisitions | — | $ 607,217 | $ 91,448 | $ 166,786 | $ 105,023 |
| Other | $ 129,705 | $ 285,427 | $ 166,524 | $ 71,378 | $ 183,168 |
| Total | $ 129,705 | $ 892,644 | $ 257,972 | $ 238,164 | $ 288,191 |
| Average Realized Oil Price (per barrel) | $ 21.27 | $ 21.93 | $ 25.55 | $ 16.92 | $ 11.06 |
| Average Realized Gas Price (per Mcf) | $ 2.26 | $ 3.30 | $ 3.22 | $ 1.89 | $ 1.87 |
| **Operational Highlights** | | | | | |
| Proved Oil Reserves (MBbls) | 348,697 | 322,261 | 318,560 | 303,190 | 164,457 |
| Proved Gas Reserves (Mcf) | 1,083,546 | 1,216,724 | 1,023,208 | 988,989 | 806,833 |
| Total Proved Reserves (MBOE) | 529,288 | 535,048 | 489,095 | 468,022 | 298,929 |
| Annual Sales Volumes (MBOE) | 32,500 | 34,581 | 28,816 | 24,936 | 24,307 |
| Average Daily Oil Production (MBbls) | 57 | 60 | 54 | 46 | 45 |
| Average Daily Gas Production (MMcf) | 191 | 207 | 147 | 132 | 129 |
| Average Daily Oil Equivalent Production (MBOE) | 89 | 95 | 79 | 68 | 67 |
| Three-Year Average Finding Cost (per BOE) | $ 6.75 | $ 3.89 | $ 2.64 | $ 2.56 | $ 4.50 |

*The financial highlights, excluding capital expenditures and average realized prices, reflect the presentation of the company's operations in Trinidad and Ecuador as discontinued operations for all periods. The operational highlights, capital expenditures and average realized prices include the results of the company's operations in Trinidad and Ecuador for all periods.*

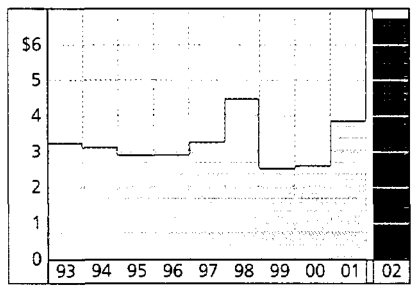
**Proved Reserves**
(MMBOE)



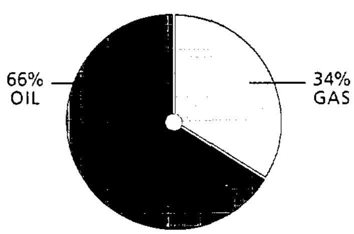

**Annual Sales Volumes**
(MMBOE)



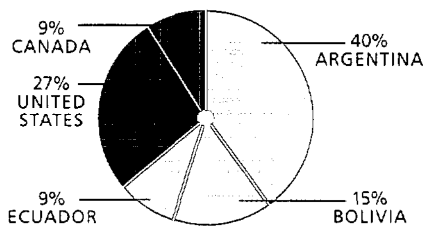

**Three-Year Average Finding Cost**
($ per BOE)



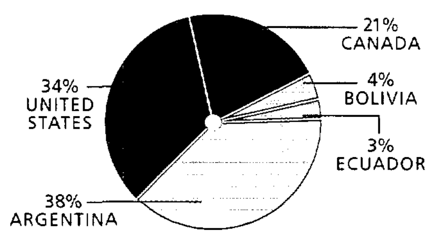

**Proved Reserves**
(by Product)




**Proved Reserves**
(by Country)




**Production**
(by Country)



Charles C. Stephenson, Jr.    S. Craig George

In 2002, we took a disciplined approach to ensure our goals were achieved.

# To Our Stockholders

In last year's letter we pledged that in 2002 we would focus on managing our financial leverage, maintaining liquidity and positioning the company for long-term growth. At the same time, we pledged to be vigilant to the unfolding events in Argentina and proactive in the management of those assets. With this focus, early in the year we temporarily suspended our traditional emphasis on building value through growth in favor of repositioning the company in a prudent manner. Over the past year, we have successfully navigated through some very challenging times, testing our agility, adaptability and perseverance to execute our plan.

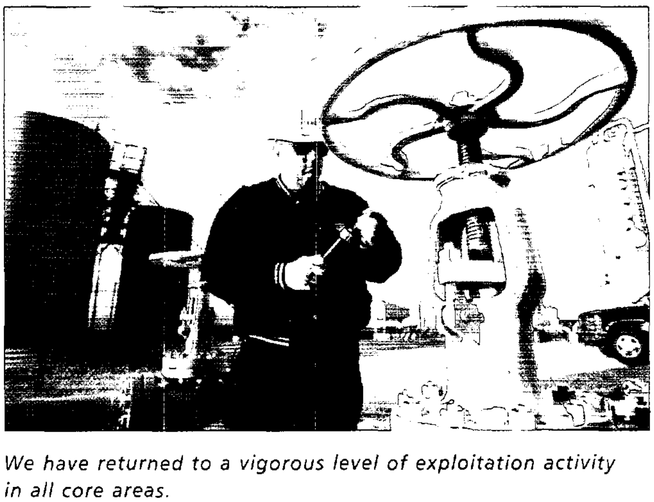
With prices having weakened during the second half of 2001, we entered 2002 with NYMEX prices of oil and gas at $19.84 per barrel and $2.65 per MMBtu, respectively. Our historical tactic of issuing equity in order to reduce balance sheet leverage following a significant acquisition for cash was interrupted first by declining hydrocarbon prices and its effect on our share price and then by the more profound effect on our share price as international attention was focused on Argentina's political and economic turmoil. Capital market concerns over the uncertainty in Argentina, accentuated by the level of debt on the balance sheet from our mid-2001 Canadian acquisition and the uncertainty associated with disappointing performance by that acquisition, depressed our stock price throughout the year. Although the NYMEX prices of both oil and gas rose from their levels at the beginning of 2002, averaging $26.08 per barrel and $3.25 per MMBtu for the year, respectively, the market remained skeptical of the ability of the price of oil to be sustained, preferring stocks whose asset mix was more substantially leveraged to domestic natural gas.

## Our experienced and talented team members were central to skillfully navigating through the challenging times of this past year and plotting the course forward.

Early in the year, we set out to ensure greater future financial strength and flexibility through the implementation of a $200 million debt reduction program. We also took advantage of the historically low interest rate environment to replace floating rate debt outstanding under our bank facility and lengthen debt maturities by issuing $350 million of 8 1/4% Senior Notes due in 2012. A combination of proceeds from non-strategic asset sales and cash flow in excess of capital expenditures allowed us to achieve and exceed our plan. We began this past year with just over $1 billion in net long-term debt. Today, our net long-term debt balance is below $775 million. Going forward, we are committed to operate in a net debt-to-book capitalization range of 40 to 55 percent.

In 2002, we reduced our capital spending and curtailed our acquisition efforts as part of our commitment to debt reduction. We reinvested only 54 percent of cash provided by operating activities, or $130 million, in exploitation and exploration opportunities. These investments and the impact of reserve revisions resulted in total additions to proved reserves of 40 MMBOE, replacing 123 percent of our production at a cost of $3.23 per BOE. Over the last three years, our total finding cost of reserves has averaged $6.75 per BOE and we have replaced 189 percent of production. At year-end, the pre-tax net present value discounted at 10 percent (PV 10) of our 529 million BOE of proved reserves was $4 billion, using year-end 2002 prices as mandated by the SEC. Using more moderate NYMEX pricing assumptions of $25.00 per barrel and $4.00 per MMBtu would imply total proved reserves of 519 million BOE and a PV 10 of $2.8 billion.

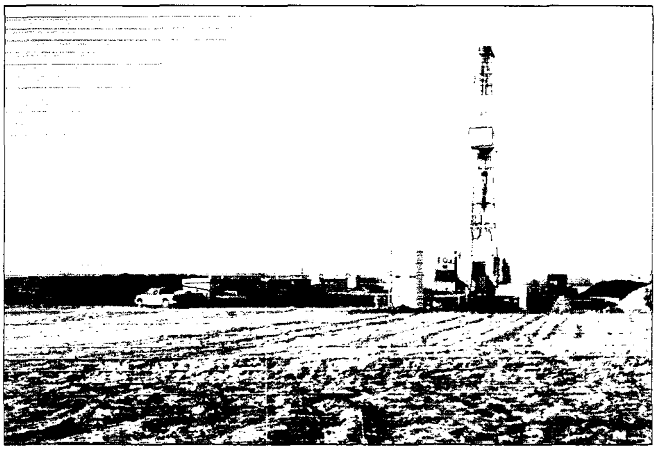
Total production, including Ecuador production now classified as a discontinued operation, totaled 32.5 million BOE, exceeding our target of 32.1 million BOE. In addition, we met or exceeded our public targets for cash flow and EBITDAX. Per BOE targets for lease operating expenses and general and administrative costs were also met or bettered. However, production, cash flow and EBITDAX were all less than last year and per BOE costs were slightly higher compared to last year. This was due to the combined effects of non-strategic asset sales, which occurred during the fourth quarter of 2001 and the second quarter of 2002, along with natural production declines as well as the impact of reduced capital spending.



*We have returned to a vigorous level of exploitation activity in all core areas.*

Although we met key targets and successfully executed our debt reduction plan, large non-cash charges for the impairments of both goodwill and oil and gas properties and the impact of the cumulative effect of an accounting change earlier in 2002, nearly all of which related to the company's operations in Canada, drove 2002 financial results to a net loss of $143.7 million, or $2.27 per share. This compares to the prior year's net income of $133.5 million, or $2.09 per diluted share. A decrease in production and lower realized oil and gas prices, combined with higher exploration costs and interest expense, contributed to the decline in net income.

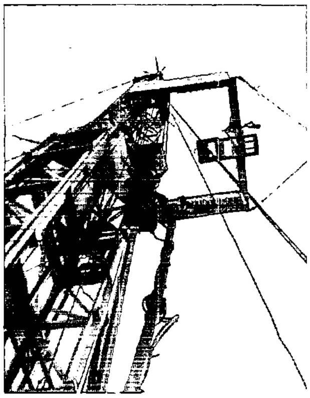
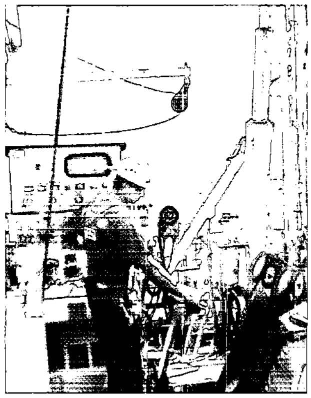
We continued to position the company for near-term growth by resuming our drilling program in Argentina in late 2002. We have created substantial growth from our activity in Argentina since entering the country in 1995 and expect that with apparent stabilization returning to the country, it can fully contribute to our growth in the future. We are also supporting our long-term growth goals by continuing to build an inventory of exploration prospects with varied timing and risk levels in North America to support internal growth. We have also added to the inventory of frontier exploration prospects with company transforming potential. We spent $50 million on exploration, including lower-risk extensional projects, during 2002 principally in North America and frontier areas. We had discoveries in the United States, Canada and Yemen during the year. These successes and the investments in building prospect inventory to be made in 2003 will create a solid foundation for future growth. In order to focus on the most meaningful opportunities, we have decided to divest certain non-strategic properties in Canada. Canada remains an important core area to us, and after the sale of assets, is anticipated to provide a strong base from which to expand operations in the future. Funds from these asset sales will be used to either reduce debt or acquire new properties.



*Over the last three years, our total finding cost of reserves has averaged $6.75 per BOE and we have replaced 189 percent of our production.*

We have developed our 2003 non-acquisition capital spending budget of $185 million targeting our three main operating areas: the United States, Argentina and Canada. Early signs of a tentative recovery in the U.S. economy and the prospect of a modest increase in worldwide oil demand beginning from a historically low level of crude oil and product

**We see 2003 to be a pivotal and exciting year, completing our balance sheet improvement and repositioning activities, while reinitiating profitable growth.**

*We are moving forward with our most robust exploration program to date and have allocated 30 percent of our planned non-acquisition capital budget for exploration.*

inventories in the United States, suggest a positive operating environment. However, the prospect of hostilities with Iraq and the reduction in crude supplies from Venezuela could result in a much more volatile scenario unfolding in the coming year.

In addition to the near-term actions reflected in our 2003 non-acquisition capital budget, our goals include taking steps to ensure the achievement of our long-term growth strategy. We will continue to apply the majority of capital expenditures to convert undeveloped reserves into production and to expand and diversify our North American exploration portfolio. We will strive to maintain an exposure to company-transforming frontier exploration plays. We will be on the lookout for acquisition opportunities with significant upside potential that can be financed with an appropriate amount of equity. We will work to continue reducing our leverage in order to maintain financial flexibility, operating within our stated net debt-to-book capitalization range.

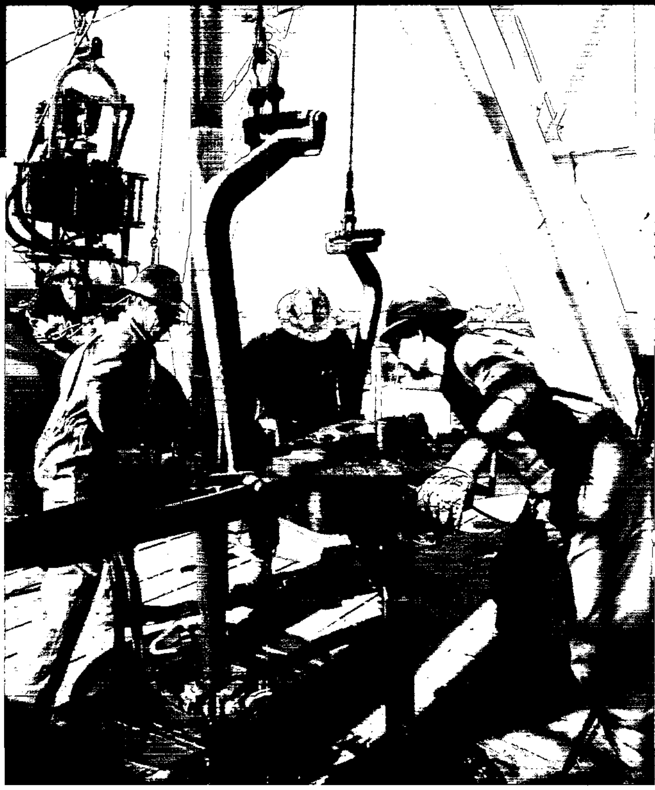
We welcome two new independent directors to the board of directors. Gerald Maier, former chairman of TransCanada PipeLines, joined the board in September 2002. In addition, Rex Adams, professor of business administration and former dean of the Fuqua School of Business at Duke University, also joined our board of directors in February 2003. Mr. Adams was formerly vice president, administration for Mobil Corporation. Their individual achievements and depth of industry experience will bring a wealth of unique insight to our board. Independent directors now constitute the majority of our board as a result of director additions which began in 2001 and we consider this an important milestone in our ongoing efforts to enhance our corporate governance. We will continue to provide full and transparent disclosure of financial information as we have in the past.

We thank our employees for their continued dedication and perseverance in the pursuit and achievement of our 2002 goals. Our experienced and talented team members were central to skillfully navigating through the challenging times of this past year and plotting the course forward. Entering 2003, we have returned to a vigorous level of exploitation activity in all core areas, are going forward with our most robust exploration program to date and see an improved environment for acquisitions. We see 2003 to be a pivotal and exciting year, completing our balance sheet improvement and repositioning activities while reinitiating profitable growth from our streamlined asset platform.

**Charles C. Stephenson, Jr.**
Chairman of the Board of Directors

**S. Craig George**
President and Chief Executive Officer

*March 17, 2003*



We took action to reduce debt and increase our exposure to natural gas assets.

# Year in Review

## 2002 Operations and Financial Results

### Leverage Reduction Goals Achieved

Early in the year, we announced a plan to reduce financial leverage and streamline our asset portfolio. Our goal to lower net long-term debt by $200 million from the $1 billion level at year-end 2001 was achieved through a combination of non-strategic asset sales and the application of operating cash flow in excess of capital expenditures. Non-strategic interests in California and Trinidad were sold. Although we had successfully drilled a discovery well in Trinidad in 2001 creating value through the addition of proved reserves, the property sale allowed Vintage to reduce debt, capture a substantial return on investment and avoid a lengthy wait for further gas market development. We also closed the sale of our interest in Ecuador for $137 million on January 31, 2003. After-tax proceeds from the combined asset sales and the application of excess cash flow allowed us to reduce our net long-term debt to $775 million at the end of 2002, pro forma for the January 2003 sale. Subsequently, the company had no bank debt as of February 2003 and the nearest maturity of fixed-rate notes is 2009.

### North America

Making debt reduction a high priority and using a portion of internally generated cash flow to accomplish this key financial goal significantly limited the amount of capital available for exploitation and exploration. Capital expenditures for oil and gas activities were limited to $130 million, or 54 percent of cash provided by operating activities. The U.S. capital spending was restricted to $30 million compared to $62 million in 2001, and activity was split equally between exploitation and exploration. Exploitation focused on maintaining production levels while gas-focused exploration success was achieved in the Mid-Continent area and Louisiana.

Canada's spending of $59 million was primarily focused on exploitation and extensional drilling, much of it targeting natural gas plays. For the year, 69 net exploitation and extensional wells were drilled with a 61 percent success rate, and 74 successful net workovers were completed. Results in Canada were disappointing; however, geological and drilling success translated into limited production and economic success. This was compounded by several fields experiencing significant downward revisions in reserves and estimated future cash flows resulting from unanticipated water encroachment.

production declined throughout the year, 2002 total production was flat with 2001 as a result of a property acquisition in late 2001 and the 100 percent drilling success rate achieved.

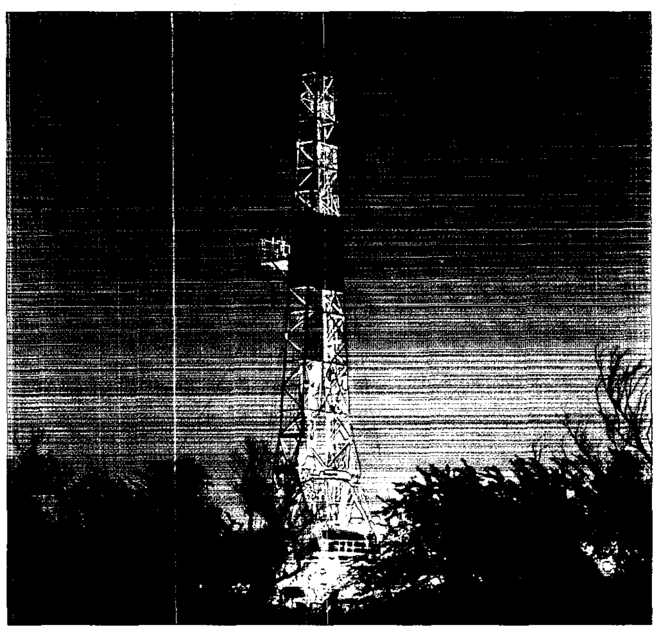
Nearly 90 percent of our production from Argentina is oil and we continue to enjoy a competitive advantage in our ability to export a large portion of our oil production. Proceeds from oil exports are paid in U.S. dollars into U.S. banks. Net of the required 30 percent repatriation of funds to Argentina, export cash flows help support the corporate capital budget and debt reduction. The negative impact of the

**We surpassed our $200 million debt reduction plan from the combination of non-strategic asset sales and cash flow in excess of capital expenditures.**

## South America

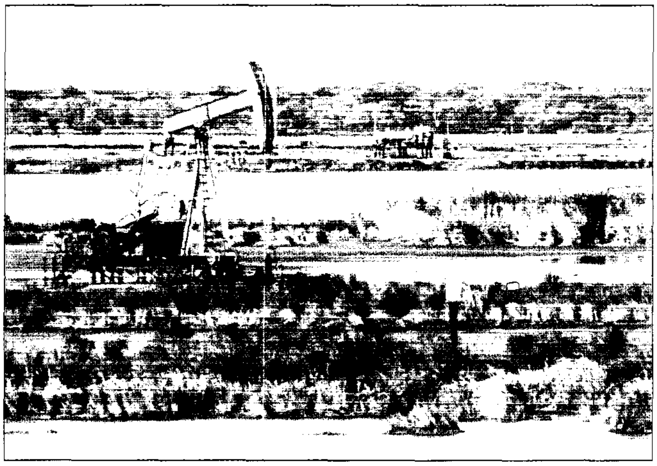
The political and economic turbulence in Argentina during the past year created new challenges. Argentina abandoned its long-standing policy of pegging its currency to the U.S. dollar, resulting in the devaluation of the peso. In addition, a 20 percent tax on oil exports was imposed effective March 1, 2002, for a period of not more than five years. The economic issues that led to these events and the subsequent political instability led us to limit our capital spending, focusing on maximizing the repatriation of our cash flow and maintaining profitability while adapting to the altered economic environment and uncertainty.

Capital spending was restricted to $19 million compared to $77 million during 2001, allowing the drilling of only 18 net wells and the completion of 88 successful net workovers. Although daily



*Exploitation in the United States focused on maintaining production levels while gas-focused exploration success was achieved.*

## Vintage resumed exploitation drilling in Argentina in late 2002 as a result of perceived stabilization in the economic and political environment.



*We will continue to apply the majority of our budgeted capital expenditures to convert undeveloped reserves into production, fueling longer-term growth.*

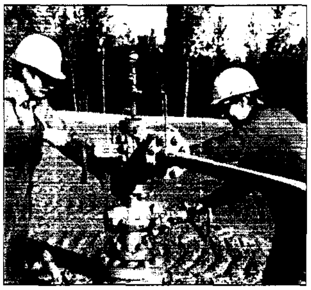
export tax was significantly offset by the benefit of reduced costs in U.S. dollar terms resulting from the peso devaluation.

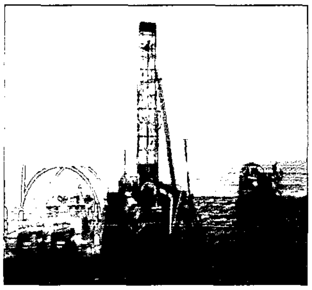
During the second half of the year, the peso stabilized relative to the U.S. dollar, the trend in the rate of inflation improved substantially, the current government remained stable, new elections were scheduled and the government of Argentina made progress in negotiations with the IMF. As a result of these events and attractive drilling economics, Vintage reinitiated drilling in December 2002. Plans call for increased activity in 2003, predicated on continued political and economic stability.

Brazil's demand for Bolivian gas continues to remain soft as a result of Brazil's weakened economy, inexpensive hydroelectric power and delays in construction of natural gas-fired power generation plants. Softer end-market gas demand in Brazil in 2002 limited Vintage's Bolivian gas production to 7.1 Bcfe compared to 9.7 Bcfe in 2001.

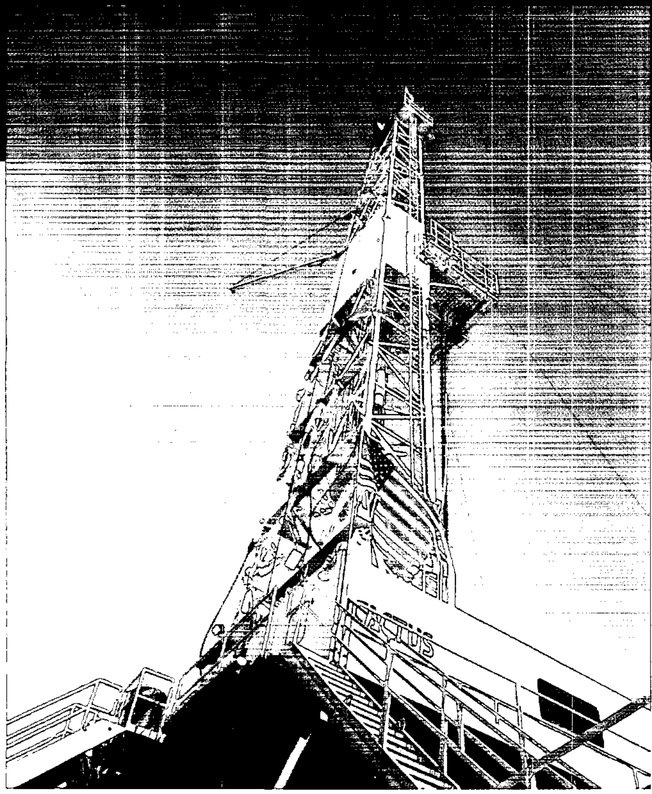
### International Exploration

Approximately $7 million was spent on drilling or delineating other exploration plays last year with the largest portion allocated to Yemen. Vintage's second drilling campaign in Yemen drilled three wells in 2002 based on new 3-D seismic and geochemical surveys in the S-1 Damis Block undertaken in 2001. An oil discovery in the Lam formation made by the An Nagyah #2 well during the fourth quarter of 2002 has resulted in additional appraisal drilling. In the Northwest Territories, Vintage acquired additional seismic and geochemical surveys during 2002 to aid in the evaluation of its three exploration licenses that are 50 percent owned and cover 880,000 gross acres in the central Mackenzie Valley of Canada. □





*We are supporting our long-term growth goals by continuing to build an inventory of exploration prospects with varied timing and risk levels in North America.*



Our capital budget provides for development programs in both North and South America and worldwide exploration.

# 2003 Directions
## Revitalizing Growth in Stockholder Value

### 2003 Goals

Our 2003 plan calls for us to:

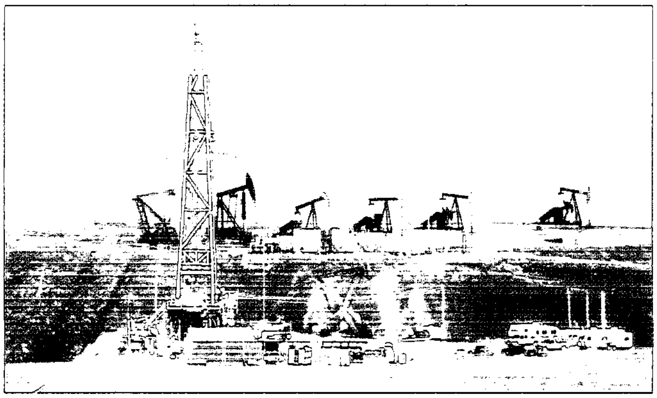
- Execute exploitation plans in core areas of the United States, Argentina and Canada to mitigate production declines;
- Continue to build momentum and project inventory in the gas-focused North American exploration program to support future organic growth;
- Execute our Canadian strategy to reposition via asset sales and focused exploitation and exploration;
- Continue to reduce leverage primarily through non-strategic property sales, along with the application of any cash flow in excess of capital expenditures;
- Invest in high potential frontier exploration opportunities which can have a transforming impact on the company; and
- Seek acquisition opportunities as a source of growth.

### Capital Spending Budget

The 2003 non-acquisition capital spending level has been set at $185 million, an increase of 42 percent over the restricted spending of 2002, but less than 2003 targeted cash flow under our assumed NYMEX price scenario of $26.00 per barrel of oil and $4.50 per MMBtu for gas. The budget allocates 70 percent, or $129 million, of the total to lower-risk exploitation activities in the United States, Argentina and Canada while devoting the remaining 30 percent, or $56 million, to exploration projects in North America and the frontier areas.

### United States

Approximately 43 percent, or $80 million, of the total capital budget is targeted for the United States with most allocated to exploitation and the remaining $31 million targeting the drilling of several



*Exploitation work continues on the Pleito Ranch property in California. Light, sweet crude oil is the objective of this directional drilling program.*

### Canada

Our principal effort in Canada during 2003 will concentrate on technology-driven exploitation and exploration opportunities that will have greater potential impact on future production. Based on familiarization, drilling results and performance reviews of our property base, we have determined that certain properties do not fit our long-term growth strategy. In order to focus on the most meaningful opportunities, we have decided to divest certain non-strategic Canadian properties. This action is anticipated to provide a strong base from which to expand operations in the future.

**We will continue to build financial strength in order to execute our acquisition, exploitation and exploration growth strategies.**

potentially significant gas exploration prospects and developing additional exploratory prospect inventory. Exploitation activities will be comprised of horizontal drilling for oil in the Luling and West Ranch fields in south central Texas and several fields in California, as well as workover activity across all of our existing operating areas.

Entering 2003, exploration activity is under way in south Louisiana, west Texas and the Texas Gulf Coast. Drilling will initially focus on 3-D seismic predicated deep gas prospects in south Louisiana near the Lily Boom field. In west Texas, a multi-well horizontal drilling program began in late 2002 and will continue into 2003. Vintage has a 33 percent interest in the first of three separate prospects covering over 19,500 acres. In the Texas Gulf Coast region, a 500-square-mile 3-D seismic data set is being used to generate prospects where drilling is expected to commence in 2003.

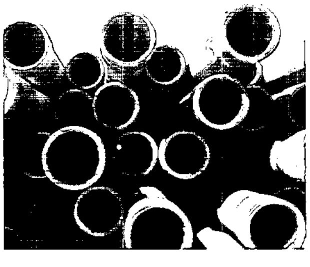
Accordingly, a budget of $38 million has been allocated to Canadian operations with 79 percent, or $30 million, of the total to be used primarily for exploitation work. The remainder is targeted for drilling exploration prospects in Alberta, British Columbia and the Northwest Territories. In an effort to reposition our portfolio of assets and prospects, our new ventures group will continue to build an inventory of gas-focused drill bit opportunities within and external to existing areas of activity.

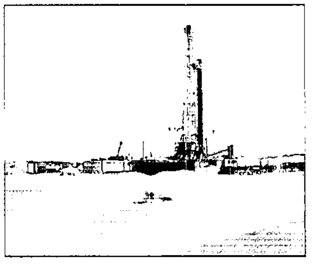
### Argentina

Argentina's capital budget has been raised substantially to $48 million for 2003 in contrast to the severely restricted spending of $19 million in 2002. Spending is predicated upon continued political and economic stability which appears to have been achieved over the past months as evidenced by such events as the signing of a short-term agreement with the IMF that is in place through August 2003, stabilization in the currency exchange rate of the peso and moderated inflation. Presidential elections planned for 2003 should position Argentina to adopt longer-term economic policies that will create growth goals that are compatible with our planned activity. Our activity in Argentina during 2003 is anticipated to approach historical levels with the drilling of 63 wells. Vintage has returned two drilling rigs to work and intends to add a third rig during 2003. Under the budgeted plan, we expect to begin growing production again, targeting a 10 percent increase in fourth quarter 2003 oil production compared to the same period in 2002.

## International Exploration

Approximately $16 million is targeted to be spent for international exploration projects located outside of North America. Frontier exploration, such as projects in Yemen and the Northwest Territories of Canada, generally are characterized by longer time horizons. We are in our second drilling campaign in Yemen and are drilling to assess the potential of the oil discovery in the Lam formation made by the An Nagyah #2 during the fourth quarter of 2002. Pending the drilling results, the company may drill one or more additional wells in the current campaign. Vintage has a 75 percent working interest in the block.





*International exploration exposes us to potentially high impact targets in areas outside the company's core operations.*

*Planned drilling in Argentina will return to historical activity levels and will reinvigorate growth.*

The exploration efforts in the Northwest Territories to date in 2003 focused on the completion and testing of the three previously drilled wells and the drilling of an additional well. These exploration efforts were unsuccessful at discovering commercial quantities of hydrocarbons. Data obtained from these wells will be used to continue the assessment of the exploration potential of the Northwest Territories. The company may also obtain additional seismic and/or geochemical data to aid in the evaluation of future exploration prospects.

Vintage has a 70 percent working interest in two exploration blocks situated in the Po Valley, an industrial region of northern Italy which has a well-documented production history and pipeline infrastructure serving a highly developed gas market. Vintage is the operator of the Bastiglia and Cento blocks covering approximately 275,000 acres. The process of well permitting is under way and Vintage intends to spud two exploration wells during the fourth quarter of 2003.

## Acquisition Activity

Vintage will continue to seek acquisitions to foster reserve and production growth and contribute toward the goal of rebalancing its portfolio toward North America. It appears that property packages for sale by the majors, as well as those emanating from large independents, may provide for robust activity levels in 2003. It also appears that the capital markets are now receptive to financing such acquisitions and any significant acquisitions by Vintage would be accompanied by appropriate levels of equity capital. □

# Directors

**William L. Abernathy**
Executive Vice President and Chief Operating Officer
Vintage Petroleum, Inc.

**Rex D. Adams**
Professor and Former Dean of the Fuqua School of Business
Duke University

**William C. Barnes**
Executive Vice President and Chief Financial Officer,
Secretary and Treasurer
Vintage Petroleum, Inc.

**S. Craig George**
President and Chief Executive Officer
Vintage Petroleum, Inc.

**Bryan H. Lawrence** (1,2,3)
Senior Manager
Yorktown Partners LLC

**Joseph D. Mahaffey** (1,2,3)
Former Managing Director
The Fremont Group

**Gerald J. Maier** (1,2,3)
Former Chairman
TransCanada PipeLines

**John T. McNabb, II** (1,2,3)
Chief Executive Officer
Growth Capital Partners, Inc.

**Charles C. Stephenson, Jr.**
Chairman of the Board of Directors
Vintage Petroleum, Inc.

Committees: Audit (1), Compensation (2), Nominating (3)

# Officers

**Charles C. Stephenson, Jr.**
Chairman of the Board of Directors

**S. Craig George**
President and Chief Executive Officer

**William L. Abernathy**
Executive Vice President and Chief Operating Officer

**William C. Barnes**
Executive Vice President and Chief Financial Officer,
Secretary and Treasurer

**William E. Dozier**
Senior Vice President – Business Development

**Kellam Colquitt**
Vice President – Exploration

**Robert W. Cox**
Vice President – General Counsel

**J. Chris Jacobsen**
Vice President – U.S. Operations

**Andy R. Lowe**
Vice President – Marketing

**Michael F. Meimerstorf**
Vice President and Controller

**Robert E. Phaneuf**
Vice President – Corporate Development

**Larry W. Sheppard**
Vice President – New Ventures

**Martin L. Thalken**
Vice President – Acquisitions

**Gary A. Watson**
Vice President – Canadian Operations

## Forward-Looking Statements

This Annual Report includes certain statements that may be deemed to be "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. All statements in this Annual Report, other than statements of historical facts, that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future, including future capital expenditures (including the amount and nature thereof), the drilling of wells, reserve estimates, future production of oil and gas, future discretionary cash flows, future reserve activity and other such matters are forward-looking statements. Although the Company believes the expectations expressed in such forward-looking statements are based on reasonable assumptions within the bounds of its knowledge of its business, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements.

Factors that could cause actual results to differ materially from those in forward-looking statements include: oil and gas prices; exploitation and exploration successes; actions taken or to be taken by Argentina as a result of its political and economic circumstances and changes in the estimated or expected impact on the Company; continued availability of capital and financing; general economic, market or business conditions; acquisition opportunities (or lack thereof); changes in laws or regulations; risk factors listed from time to time in the Company's filings with the Securities and Exchange Commission; and other factors. The Company assumes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2002

OR

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

For the transition period from to

Commission file number 1-10578

# VINTAGE PETROLEUM, INC.

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Delaware** | **73-1182669** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| **110 West Seventh Street** | |
| **Tulsa, Oklahoma** | **74119-1029** |
| (Address of principal executive offices) | (Zip Code) |

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

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

| Title of each class | Name of each exchange on which registered |
|---|---|
| Common Stock, $.005 Par Value | New York Stock Exchange |
| Preferred Share Purchase Rights | New York Stock Exchange |

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

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

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

Indicate by check mark whether the Registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes X No__

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

As of February 28, 2003, 63,936,275 shares of the Registrant's Common Stock were outstanding.

## DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's Proxy Statement for the Annual Meeting of Stockholders to be held May 13, 2003, are incorporated by reference into Part III of this Form 10-K.

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VINTAGE PETROLEUM, INC.
FORM 10-K
YEAR ENDED DECEMBER 31, 2002
TABLE OF CONTENTS

## PART I



## PART II



## PART III



## PART IV

## Certain Definitions

**As used in this Form 10-K:**

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

"Mcf" means thousand cubic feet, "MMcf" means million cubic feet, "Bcf" means billion cubic feet, "Tcf" means trillion cubic feet, "MMBtu" means million British thermal units, "Bbl" means barrel, "MBbls" means thousand barrels, "MMBbls" means million barrels, "BOE" means equivalent barrels of oil, "MBOE" means thousand equivalent barrels of oil and "MMBOE" means million equivalent barrels of oil.

Unless otherwise indicated in this Form 10-K, gas volumes are stated at the legal pressure base of the state or area in which the reserves are located and at 60° Fahrenheit. BOE are determined using the ratio of six Mcf of gas to one Bbl of oil.

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

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

## Forward-Looking Statements

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

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

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

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

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

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

## PART I

### Items 1 and 2. Business and Properties.

#### Website Access to Reports

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

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

#### General

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

At December 31, 2002, the Company owned and operated producing properties in nine states in the U.S., with its domestic proved reserves located primarily in four core areas: West Coast, Gulf Coast, East Texas and Mid-Continent. During 2001, the Company significantly expanded its North American operations in Canada through the acquisition of 100 percent of Genesis Exploration Ltd. ("Genesis," now Vintage Petroleum Canada, Inc.). See "Acquisitions." Additionally, the Company has international core areas located in Argentina and Bolivia. In Argentina, the Company owns 20 oil concessions, 16 of which are operated by the Company. Fourteen of these operated concessions are located in the south flank of the San Jorge Basin in southern Argentina. The Company expanded its Argentina core area into the Cuyo Basin in western Argentina with the purchase of the Piedras Colorados and Cachueta concessions in 2000, and the purchase of the La Ventana and Rio Tunuyan concessions in 2001. See "Acquisitions." In Bolivia, the Company owns and operates three blocks in the Chaco Plains area of southern Bolivia and the Naranjillos concession located in the Santa Cruz Province. The Company has exploration activities currently ongoing in Yemen and Italy. The Company also previously operated three blocks in the Oriente Basin in Ecuador. However, on January 31, 2003, the Company sold its operations in Ecuador. See "Divestitures."

As of December 31, 2002, the Company owned interests in 3,567 gross (3,006 net) productive wells in the U.S., of which approximately 89 percent are operated by the Company, 720 gross (483 net) productive wells in Canada, of which approximately 61 percent are operated by the Company, 1,589 gross (1,428 net) productive wells in Argentina, of which approximately 83 percent are operated by the Company, 15 gross (14 net) productive wells in Bolivia, all of which are operated by the Company, and 11 gross (8 net) productive wells in Ecuador, all of which were operated by the Company. As of December 31, 2002, the Company's properties had proved reserves of 529.3 MMBOE, comprised of 348.7 MMBbls of oil and 1.1 Tcf of gas, with a present value of estimated future net revenues before income taxes (utilizing a 10 percent discount rate) of $4.0 billion and a standardized measure of discounted future net cash flows of $2.7 billion. From the first quarter of 2000 through the fourth quarter of 2002, the Company increased its average net daily production from 52,900 Bbls of oil to 53,300 Bbls of oil and from 125,000 Mcf of gas to 182,200 Mcf of gas.

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

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

**Business Strategy**

The Company's overall goal is to maximize its value through profitable growth in its oil and gas reserves and production. The Company has been successful at achieving this goal through its ongoing strategy of (a) acquiring producing oil and gas properties with significant upside potential at favorable prices, (b) focusing on exploitation, development and exploration activities to maximize production and ultimate reserve recovery on existing properties and undeveloped properties, (c) maintaining a low cost structure and (d) maintaining financial flexibility. Key elements of the Company's strategy include:

- *Acquisitions of Producing Properties.* The Company has an experienced management and technical team which focuses on acquisitions of operated producing properties that meet its selection criteria, which include (a) significant potential for increasing reserves and production through exploitation, development and exploration, (b) favorable purchase price and (c) opportunities for improved operating efficiency. The Company's emphasis on property acquisitions reflects its belief that continuing consolidation and restructuring activities on the part of major integrated, large independent and national oil companies has afforded in the past, and should afford in the future, favorable opportunities to purchase domestic and international properties. This acquisition strategy has allowed the Company to rapidly grow its reserves at favorable acquisition prices. From January 1, 2000, through December 31, 2002, the Company has spent $698.7 million acquiring 96.2 MMBOE of proved oil and gas reserves at an average acquisition cost of $7.26 per BOE. The Company replaced, through acquisitions, approximately 100 percent of its production of 95.9 MMBOE during the same period. For additional information, see "Acquisitions." Although the Company made no acquisitions in 2002, management is continually identifying and evaluating acquisition opportunities, including acquisitions that would be significantly larger than many of those consummated to date by the Company. No assurance can be given that any such acquisitions will be successfully consummated.

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

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

- *Financial Flexibility.* The Company is committed to maintaining financial flexibility, which management believes is important for the successful execution of its acquisition, exploitation and exploration strategy. Since 1990, the Company has completed five public equity offerings, two public debt offerings and three Rule 144A private debt offerings, all of which have provided the Company with aggregate net proceeds of approximately $1.2 billion. The Company announced in early 2002 plans to reduce debt by $200 million through a combination of asset sales and cash flows in excess of planned capital expenditures. The sale of the Company's operations in Trinidad and its heavy oil properties in California in 2002, along with the Company's operations in Ecuador in January 2003, resulted in the achievement of the Company's $200 million debt reduction goal. After giving pro forma effect to the estimated after-tax proceeds from the sale of its operations in Ecuador, the Company's net debt at December 31, 2002, would be approximately $775 million. This compares to net debt at December 31, 2001, of approximately $1.0 billion. The Company is considering additional debt reduction in 2003 to continue its progress toward lower debt levels. Currently, the Company anticipates that any such de-leveraging would be funded by additional sales of non-strategic assets. Cash on hand, internally generated cash flows, the borrowing capacity under its revolving credit facility and its ability to adjust its level of capital expenditures are the Company's major sources of liquidity. In addition, the Company may use other sources of capital, including the issuance of additional debt securities or equity securities, to fund any major acquisitions it might secure in the future and to maintain its financial flexibility. For further information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity" included elsewhere in this Form 10-K.

**Acquisitions**

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

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

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

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

**Divestitures**

During 2002, the Company continued its divestiture program designed to sell properties that were either marginally economical or non-strategic to the Company's areas of operation. The Company determined that the level of investment and time horizon required to continue the development of its interests in Ecuador and Trinidad were inconsistent with the timing of its desire to reduce leverage. These assets, along with the Company's remaining heavy oil properties in the Santa Maria area of southern California, were identified for sale. The Company's heavy oil properties in the Santa Maria area of southern California were sold in June 2002 for $9.5 million in cash and a note receivable for $6 million bearing monthly payments of $360,000, plus interest, with final maturity in June 2003. The Company received a cash payment as final settlement of this note in October 2002. The Company's interest in Trinidad was sold in July 2002 for $40 million in cash. In total, property sales in 2002 resulted in $48.4 million in gains ($25.1 million after tax), which were included in the Company's 2002 operating results. Combined, the Company estimates that the properties sold in 2002 accounted for proved reserves of 2.4 MMBbls of oil and 65.0 Bcf of gas as of the closing dates of the sales, which represents three percent of the Company's total proved reserves at December 31, 2002.

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

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

**Exploration and Development**

The Company concentrates its acquisition efforts on proved producing properties which demonstrate a potential for significant additional development through workovers, recompletions, secondary recovery operations, the drilling of development, infill or exploratory wells and other exploitation opportunities. The Company has pursued an active workover, recompletion and development drilling program on the properties it has acquired and intends to continue these activities in the future. The Company's exploitation staff focuses on maximizing the value of the properties within its reserve base, striving to offset normal production declines and to replace the Company's annual production.

The Company's exploration program is designed to contribute significantly to its growth. Management divides the strategic objectives of its exploration program into two parts. First, in North America and Argentina, the Company's exploration focus is in its core areas where its geological and engineering expertise and experience are greatest. State-of-the-art technology, including 3-D seismic data, is employed to identify prospects. Exploration in North America is designed to generate reserve growth in this core area in combination with its exploitation activities. The Company is increasing the magnitude of this program with a goal of achieving yearly production replacement through core area exploration. Such exploration is characterized by numerous individual projects with medium to low risk. Secondly, international exploration targets significant long-term reserve growth and value creation. The Company's international exploration projects currently underway in Yemen and Italy are characterized by higher potential and higher risk.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

## Oil and Gas Properties

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

The following table sets forth estimates of the proved oil and gas reserves of the Company at December 31, 2002, as estimated by the independent petroleum consultants of Netherland, Sewell & Associates, Inc. for the U.S., Argentina and Ecuador, as estimated by the independent petroleum consultants of DeGolyer and MacNaughton for Bolivia and as estimated by the independent petroleum consultants of Outtrim Szabo Associates Ltd. for Canada:

| | Oil (MBbls) | | | Gas (MMcf) | | | MBOE |
|---|---|---|---|---|---|---|---|
| | Developed | Undeveloped | Total | Developed | Undeveloped | Total | Total |
| West Coast | 47,642 | 5,395 | 53,037 | 94,061 | 3,955 | 98,016 | 69,373 |
| Gulf Coast | 20,423 | 6,964 | 27,387 | 57,241 | 34,031 | 91,272 | 42,599 |
| East Texas | 6,860 | 661 | 7,521 | 61,039 | 14,331 | 75,370 | 20,083 |
| Mid-Continent | 622 | 738 | 1,360 | 33,513 | 20,136 | 53,649 | 10,301 |
| Total U.S. | 75,547 | 13,758 | 89,305 | 245,854 | 72,453 | 318,307 | 142,356 |
| Canada | 10,620 | 7,869 | 18,490 | 161,200 | 21,825 | 183,025 | 48,994 |
| Total North America | 86,167 | 21,627 | 107,795 | 407,054 | 94,278 | 501,332 | 191,350 |
| Argentina | 106,135 | 83,259 | 189,394 | 43,737 | 84,427 | 128,164 | 210,755 |
| Bolivia | 4,721 | 1,343 | 6,064 | 353,259 | 100,791 | 454,050 | 81,739 |
| Ecuador | 8,302 | 37,143 | 45,444 | - | - | - | 45,444 |
| Total Company | 205,325 | 143,372 | 348,697 | 804,050 | 279,496 | 1,083,546 | 529,288 |

Estimates of the Company's 2002 proved reserves set forth above have not been filed with, or included in reports to, any federal authority or agency, other than the Securities and Exchange Commission.

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

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

The following is a brief discussion of the Company's oil and gas operations in its core areas:

*West Coast Area.* The West Coast area includes oil and gas properties located primarily in Kern and Ventura counties and the Sacramento Basin of California. The Stevens, Forbes, Grubb and Sisquoc formations are the dominant producing reservoirs on the Company's acreage in California with well depths ranging from 800 feet to 14,300 feet. As of December 31, 2002, the area comprised 13 percent of the Company's total proved reserves and 49 percent of the Company's U.S. proved reserves. The Company currently operates 1,313 gross (1,278 net) productive wells in this area and owns an interest in 150 gross (eight net) productive wells operated by others. During 2002, net daily production for this area averaged approximately 15,800 BOE, or 53 percent of total net daily U.S. production. Numerous workovers and recompletion opportunities exist in the San Miguelito, Buena Vista and Rincon fields. Additional infill drilling locations are available in the San Miguelito, Pleito Ranch, and Tejon fields. The San Miguelito field also has waterflood potential that may add significant reserves and the Antelope Hills field has oil reserves that may be added through steamflood expansion.

*Gulf Coast Area.* The Gulf Coast area includes properties located in southern Texas, the southern half of Louisiana, Alabama, Mississippi and wells located in shallow state and federal waters. The reservoirs in the coastal waters and federal waters range in age from Pliocene to middle and upper Miocene and Oligocene. Reservoirs further onshore are predominantly from Eocene and Cretaceous ages. The depths of the producing reservoirs range from 1,200 feet to 14,500 feet. At December 31, 2002, the Gulf Coast area comprised approximately eight percent of the Company's total proved reserves and 30 percent of its U.S. proved reserves. The Company currently operates 1,121 gross (1,089 net) productive wells in this area and owns an additional interest in 58 gross (16 net) productive wells operated by others. During 2002, net daily production from this area averaged approximately 11,100 BOE, or 37 percent of total net daily U.S. production. A significant inventory of workovers and recompletions exist in Gulf Coast fields from Alabama to south Texas. Development drilling potential is also available in various fields in Texas and Louisiana.

*East Texas Area.* The East Texas area includes properties located in the northeastern portion of Texas and the northern half of Louisiana. The Cotton Valley, Smackover, Travis Peak and Wilcox formations are the dominant producing reservoirs on the Company's acreage in this area with wells ranging in depth from 1,300 feet to 14,800 feet. The East Texas area comprised approximately four percent of the Company's December 31, 2002, total proved reserves and 14 percent of its U.S. proved reserves. The Company currently operates 570 gross (493 net) productive wells in this area and owns an interest in an additional 79 gross (eight net) productive wells operated by others. During 2002, net daily production for this area averaged approximately 1,200 BOE, or four percent of total net daily U.S. production. Significant infill drilling potential exists on the Company's acreage in the South Gilmer, Edgewood, Southern Pine and Bear Grass fields.

*Mid-Continent Area.* The Mid-Continent area extends from the Arkoma Basin of eastern Oklahoma to the Texas panhandle and north to include Kansas. The Red Fork, Morrow, Skinner and Hoxbar formations are the dominant producing reservoirs on the Company's acreage in this area with well depths ranging from 1,560 feet to 17,260 feet. This area comprised two percent of the Company's December 31, 2002, total proved reserves and seven percent of its U.S. proved reserves. The Company currently operates 175 gross (100 net) productive wells in this area and owns an interest in an additional 101 gross (14 net) productive wells operated by others. During 2002, net daily production for this area averaged approximately 1,800 BOE, or six percent of total net daily U.S. production. Projects to improve the ultimate reserve recovery exist in the Shawnee Townsite waterflood and production response is anticipated from the Missouri Flats waterflood in 2003. The Company has signed an agreement to sell certain Mid-Continent properties. See "Divestitures."

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

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

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

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

**Marketing**

Generally, the Company's U.S. oil production is sold under short-term contracts at posted prices, plus a premium in some cases, or at NYMEX prices less a specified differential. The Company's Canadian oil production is sold under short-term contracts at posted prices. The Company's Argentine oil production is currently sold at port to Esso S.A.P.A. (the Argentine affiliate of Exxon-Mobil), ENAP (the Chilean government-owned oil company) and Shell C.A.P.S.A. at West Texas Intermediate spot prices as quoted on the Platt's Crude Oil Marketwire (approximately equal to the NYMEX reference price) less a specified differential. In Ecuador, the Company's Block 14 and Block 17 oil production was sold to various third party purchasers at West Texas Intermediate spot prices less a specified differential. During 2002, approximately 24 percent and 10 percent of the Company's total operating revenues related to oil sales to ENAP and Esso S.A.P.A., respectively.

In January 2002, the Argentine government devalued the Argentine peso ("peso") and enacted an emergency law that required certain contracts that were previously payable in U.S. dollars to be payable in pesos. Subsequently, on February 13, 2002, the Argentine government announced a 20 percent tax on oil exports, effective March 1, 2002. The tax is limited by law to a term of no more than five years. The tax of 20 percent is applied on the sales value after the tax, thus the net effect is 16.7 percent. For additional information, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Foreign Currency and Operations Risk" included elsewhere in this From 10-K. Domestic Argentine oil sales, while valued in U.S. dollars, are now being paid in pesos. Export oil sales continue to be valued and paid in U.S. dollars.

The Company currently exports approximately 70 percent of its Argentine oil production. The Company believes that this export tax will have the effect of decreasing all future Argentine oil revenues (not only export revenues) by the tax rate for the duration of the tax. The U.S. dollar equivalent value for domestic Argentine oil sales (now paid in pesos) has generally moved to parity with the U.S. dollar denominated export values, net of the export tax. The adverse impact of this tax has been partially offset by the net cost savings resulting from the devaluation of the peso on peso denominated costs and is further reduced by the Argentine income tax savings related to deducting the impact of the export tax. The export tax is not deducted in the calculation of royalty payments.

On January 2, 2003, at the Argentine government's request, crude oil producers and refiners agreed to cap amounts payable for domestic sales occurring during the first quarter 2003 at $28.50 per Bbl. The producers and refiners further agreed that the difference between the actual price and the capped price would be payable once actual prices fall below the cap. The debt payable under the agreement accrues interest at 8 percent. The total debt will be collected by invoicing future deliveries at $28.50 per Bbl after actual prices fall below the capped price. Additionally, the agreement allowed for renegotiation if the West Texas Intermediate reference price exceeded $35.00 per Bbl for ten consecutive days, which occurred on February 24, 2003.

On February 25, 2003, the agreement between the producers and the refiners was modified to limit the amount payable from refiners to producers for deliveries occurring between February 26, 2003, and March 31, 2003. While the $28.50 per Bbl payable cap was maintained, under the modified terms refiners have no obligation to pay producers for sales values that exceed $36.00 per Bbl. Furthermore, interest for debts established during this period was reduced to seven percent.

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

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

The Company has entered into certain firm gas transportation and compression agreements in Bolivia whereby the Company has committed to transport and compress certain volumes of gas at established government-regulated fees. While these fees are not fixed, they are government-regulated and therefore, the Company believes the risk of significant fluctuations is minimal. The Company entered into these arrangements to ensure its access to gas markets and currently expects to produce sufficient volumes to utilize all of the contracted transportation and compression capacity under these arrangements. Based on the current fee level, these commitments total approximately $2.7 million in 2003, $1.4 million in 2004, $0.3 million in 2005, $0.3 million in 2006, $0.3 million in 2007 and $0.6 million thereafter.

The Company has also entered into "deliver-or-pay" arrangements whereby the Company has committed to deliver certain volumes of gas to third parties in Bolivia and Argentina for a specified period of time. These volumes will be sold at market prices. If the required volumes are not delivered, the Company must pay for the undelivered volumes at the then-current market price. Similar to the firm transportation and compression agreements, the Company entered into these arrangements to ensure its access to gas markets and currently expects to produce sufficient volumes to satisfy all of its deliver-or-pay obligations. The volumes contracted under the agreement in Bolivia are 11.1 Bcf in 2003, 10.3 Bcf in 2004, 6.0 Bcf in 2005, 5.8 Bcf in 2006, 6.0 Bcf in 2007 and 13.9 Bcf thereafter. The volumes contracted under the agreement in Argentina are 2.6 Bcf in 2003, 2.6 Bcf in 2004, 3.2 Bcf in 2005, 3.3 Bcf in 2006, 3.6 Bcf in 2007 and 3.9 Bcf thereafter.

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

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

| Quarter Ending | Bbls | NYMEX Reference Price Per Bbl |
|---|---|---|
| March 31, 2003 | 1,181,000 | $ 27.32 |
| June 30, 2003 | 1,152,000 | 27.18 |
| September 30, 2003 | 936,000 | 25.37 |
| December 31, 2003 | 874,000 | 24.55 |

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

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

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

| Quarter Ending | MMBtu | NYMEX Reference Price Per MMBtu (Canadian $) |
|---|---|---|
| March 31, 2003 | 2,250,000 | C$ 7.09 |
| June 30, 2003 | 2,275,000 | 6.42 |
| September 30, 2003 | 2,300,000 | 6.39 |
| December 31, 2003 | 2,300,000 | 6.64 |

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

## Gathering Systems and Plant

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

In 1999, the Company obtained ownership and operatorship of the Santa Clara Valley gas plant located in Ventura County, California. This plant is a 1980-vintage Randall skid-mounted cryogenic expander plant designed for 17 MMcf per day of inlet gas and is complete with inlet gas compression, mole sieve dehydration facilities, propane refrigeration, natural gas liquids product storage and truck loading. There are two inlet gas systems feeding the compressor units; one is a 30-pound system and the other is an 80-pound system. Sales line pressure is at 220 pounds and is obtained with a turbo-expander compressor. The plant is currently processing approximately nine MMcf of gas per day and producing approximately 27,000 gallons per day of natural gas liquids (butane/propane). The natural gas liquids are trucked from the plant for sale and the approximate split is 30 percent gasoline and 70 percent butane/propane mix. Gas is purchased from various third parties, as well as the Company, primarily under wellhead gas purchase agreements.

## Reserves

At December 31, 2002, the Company had proved reserves of 529.3 MMBOE, comprised of 348.7 MMBbls of oil and 1.1 Tcf of gas, as estimated by the independent petroleum consultants of Netherland, Sewell & Associates, Inc. for the U.S., Argentina and Ecuador, as estimated by the independent petroleum consultants of DeGolyer and MacNaughton for Bolivia and as estimated by the independent petroleum consultants of Outtrim Szabo Associates Ltd. for Canada. No reserve estimates have been filed with any federal authority or agency other than the SEC. For additional information on the Company's oil and gas reserves, see "Oil and Gas Properties." The following table sets forth, at December 31, 2002, the present value of future net revenues (revenues less production, development and abandonment costs) before income taxes attributable to the Company's proved reserves at such date (in thousands):

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

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

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

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

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

**Productive Wells; Developed Acreage**

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

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

Productive wells consist of producing wells and wells capable of production, including gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Wells which are completed in more than one producing horizon are counted as one well. The developed acreage and productive wells in Ecuador were sold on January 31, 2003. See "Divestitures."

### Undeveloped Acreage

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

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

## 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, | | |
|---|---|---|---|
| **Production:** | **2002** | **2001** | **2000** |
| Oil (MBbls) - | | | |
| U.S. | 6,796 | 8,409 | 9,044 |
| Canada | 1,829 | 1,539 | 19 |
| Argentina (a) | 10,942 | 10,548 | 9,406 |
| Bolivia (b) | 118 | 101 | 131 |
| Continuing operations | 19,685 | 20,597 | 18,600 |
| Ecuador (c) | 1,174 | 1,375 | 1,261 |
| Trinidad | - | 2 | - |
| Total | 20,859 | 21,974 | 19,861 |
| Gas (MMcf) - | | | |
| U.S. | 24,841 | 34,168 | 35,764 |
| Canada | 29,951 | 22,132 | 312 |
| Argentina | 8,630 | 10,253 | 8,705 |
| Bolivia | 6,424 | 9,088 | 8,948 |
| Total | 69,846 | 75,641 | 53,729 |
| MBOE from continuing operations | 31,326 | 33,204 | 27,555 |
| Total MBOE | 32,500 | 34,581 | 28,816 |
| **Average Price (including impact of hedges):** | | | |
| Oil (per Bbl) - | | | |
| U.S. | $ 21.78 | $ 23.08 | $ 22.85 |
| Canada | 21.62 | 20.55 | 26.05 |
| Argentina | 20.98(d) | 21.80 | 28.25 |
| Bolivia | 20.73 | 20.06 | 29.62 |
| Continuing operations | 21.31(d) | 22.22 | 25.63 |
| Ecuador | 20.46 | 17.65 | 24.27 |
| Total | 21.27(d) | 21.93 | 25.55 |
| Gas (per Mcf) - | | | |
| U.S. | $ 2.85 | $ 4.83 | $ 3.91 |
| Canada | 2.48 | 2.50 | 5.73 |
| Argentina | .37 | 1.30 | 1.79 |
| Bolivia | 1.54 | 1.72 | 1.75 |
| Total | 2.26 | 3.30 | 3.22 |
| **Average Price (excluding impact of hedges):** | | | |
| Oil (per Bbl) - | | | |
| U.S. | $ 22.66 | $ 22.17 | $ 26.95 |
| Canada | 21.62 | 20.55 | 26.05 |
| Argentina | 21.06(d) | 20.66 | 28.25 |
| Bolivia | 20.73 | 20.06 | 29.62 |
| Continuing operations | 21.66(d) | 21.27 | 27.62 |
| Ecuador | 20.46 | 17.65 | 24.27 |
| Total | 21.60(d) | 21.04 | 27.41 |
| Gas (per Mcf) - | | | |
| U.S. | $ 2.94 | $ 4.83 | $ 3.91 |
| Canada | 2.49 | 2.50 | 5.73 |
| Argentina | .37 | 1.30 | 1.79 |
| Bolivia | 1.54 | 1.72 | 1.75 |
| Total | 2.30 | 3.30 | 3.22 |

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

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

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

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

(d) Reflects the impact of the one-time government-mandated forced settlement of domestic Argentine oil sales which decreased the Argentina, continuing operations and total average oil prices per Bbl for the year ended December 31, 2002, by $.73, $.41 and $.38, respectively.

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

**Drilling Activity**

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

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2002 | | 2001 | | 2000 | |
| | Gross | Net | Gross | Net | Gross | Net |
| **Development:** | | | | | | |
| United States - | | | | | | |
| Productive | 2 | 1.42 | 16 | 7.40 | 21 | 14.93 |
| Non-Productive | - | - | 2 | 1.45 | 2 | 1.68 |
| Canada - | | | | | | |
| Productive | 39 | 28.70 | 47 | 33.40 | - | - |
| Non-Productive | 10 | 8.40 | 7 | 6.80 | - | - |
| Argentina - | | | | | | |
| Productive | 20 | 18.00 | 68 | 68.00 | 40 | 40.00 |
| Non-Productive | - | - | 1 | 1.00 | 1 | 1.00 |
| Bolivia - | | | | | | |
| Productive | - | - | - | - | - | - |
| Non-Productive | - | - | - | - | - | - |
| Ecuador - | | | | | | |
| Productive | 3 | 2.15 | 1 | 0.75 | - | - |
| Non-Productive | - | - | - | - | - | - |
| Total | 74 | 58.67 | 142 | 118.80 | 64 | 57.61 |
| **Exploratory:** | | | | | | |
| United States - | | | | | | |
| Productive | 1 | .35 | 7 | 4.44 | 14 | 6.17 |
| Non-Productive | 1 | .25 | 4 | 2.53 | 4 | 2.02 |
| Canada - | | | | | | |
| Productive | 17 | 13.60 | 26 | 20.00 | - | - |
| Non-Productive | 19 | 18.20 | 10 | 8.90 | 1 | 0.45 |
| Bolivia - | | | | | | |
| Productive | - | - | - | - | - | - |
| Non-Productive | - | - | - | - | 3 | 3.00 |
| Ecuador - | | | | | | |
| Productive | - | - | - | - | - | - |
| Non-Productive | - | - | - | - | 1 | 1.00 |
| Yemen - | | | | | | |
| Productive | 1 | .75 | - | - | - | - |
| Non-Productive | 1 | .75 | - | - | 1 | 0.75 |
| Trinidad - | | | | | | |
| Productive | - | - | 2 | 0.72 | - | - |
| Non-Productive | - | - | - | - | - | - |
| Total | 40 | 33.90 | 49 | 36.59 | 24 | 13.39 |
| **Total:** | | | | | | |
| Productive | 83 | 64.97 | 167 | 134.71 | 75 | 61.10 |
| Non-Productive | 31 | 27.60 | 24 | 20.68 | 13 | 9.90 |
| Total | 114 | 92.57 | 191 | 155.39 | 88 | 71.00 |

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

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

### Seasonality

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

### Competition

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

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

### Regulation

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

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

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

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

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

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

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

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

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

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

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

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

The Company's operations in Canada, Bolivia, Yemen and Italy are subject to various laws and regulations in those countries. Those laws and regulations, as currently imposed, are not anticipated to have a material adverse effect upon the Company's operations. The Company's Bolivian projects are dependent, in large part, on the continued market development of the Bolivia-to-Brazil gas pipeline.

**Risk Factors**

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

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

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

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

- political conditions in oil producing regions, including the Middle East;
- domestic and foreign supplies of oil and gas;
- levels of consumer demand;
- weather conditions;
- domestic and foreign government regulations;
- prices and availability of alternative fuels; and
- overall economic conditions.

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

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

*Lower oil and gas prices may adversely affect the Company's level of capital expenditures, reserve estimates and borrowing capacity.*

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

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

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

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

- the Company's ability to obtain any necessary financing in the future for working capital, capital expenditures, acquisitions, debt service requirements or other purposes may be limited;
- a portion of the Company's cash flows from operations must be utilized for the payment of interest on its indebtedness and will not be available for financing capital expenditures or other purposes; for example, interest payments for 2002 represented approximately 24 percent of the Company's cash flows from operations before working capital changes and interest expense;
- the Company's level of indebtedness and the covenants governing its current indebtedness could limit the Company's flexibility in planning for, or reacting to, changes in its business because certain financing options may be limited or prohibited;
- the Company is more highly leveraged than some of its competitors, which may place the Company at a competitive disadvantage;
- the Company's level of indebtedness may make it more vulnerable during periods of low oil and gas prices or in the event of a downturn in its business because of its fixed debt service obligations; and
- the terms of the Company's revolving credit facility require interest and principal payments and maintenance of stated financial covenants. If the requirements of this facility are not satisfied, the lenders under this facility would be entitled to accelerate the payment of all outstanding indebtedness under this facility, and a default would be deemed to have occurred under the terms of the Company's outstanding senior and senior subordinated notes. In such event, the Company cannot provide assurance that it would have sufficient funds available or could obtain the financing required to meet its obligations.

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

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

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

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

*Acquisitions carry unknown risks including the potential for environmental problems.*

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

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

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

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

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

*The Company's international operations may be adversely affected by political and economic instability, changes in the legal and regulatory environment and other factors.*

International investments represent, and are expected to continue to represent, a significant portion of the Company's total assets. The Company has international operations in Canada, Argentina, Bolivia, Yemen and Italy. For 2002, the Company's operations in Argentina accounted for approximately 35 percent of the Company's revenues and 28 percent of its total assets. For 2002, the Company's operations in Canada accounted for approximately 17 percent of the Company's revenues and 32 percent of its total assets. During 2002, the Company's operations in Argentina and Canada represented its only foreign operations accounting for more than 10 percent of its revenues or total assets. The Company continues to identify and evaluate international opportunities, but currently has no binding agreements or commitments to make any material international investment. As a result of such significant foreign operations, the Company's financial results could be affected by factors such as changes in foreign currency, exchange rates, weak economic conditions or changes in the political climate in these foreign countries.

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

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

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

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

- the realized prices the Company receives for oil and gas that it produces and sells;
- the timing of repatriations of cash to the U.S.;
- the amount of permitted export sales;
- the Argentine banking system;
- the Company's asset valuations; and
- peso-denominated monetary assets and liabilities.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

*Industry competition may impede the Company's growth.*

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

## Employees

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

**Item 3. Legal Proceedings.**

The Company is a named defendant in lawsuits and is a party in governmental proceedings from time to time arising in the ordinary course of business. While the outcome of such lawsuits or proceedings against the Company cannot be predicted with certainty, management does not expect these matters to have a material adverse effect on the Company's financial position or results of operations.

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

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

**Item 4A. Executive Officers of the Registrant.**

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

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

Mr. Stephenson, a co-founder of the Company, has been a Director since June 1983 and Chairman of the Board of Directors of the Company since April 1987. He was also Chief Executive Officer of the Company from April 1987 to March 1994 and President of the Company from June 1983 to May 1990. From October 1974 to March 1983, he was President of Santa Fe-Andover Oil Company (formerly Andover Oil Company), an independent oil and gas company ("Andover"), and from January 1973 to October 1974, he was Vice President of Andover. Mr. Stephenson has a B.S. Degree in Petroleum Engineering from the University of Oklahoma, and has approximately 43 years of oil and gas experience.

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

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

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

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

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

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

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

Mr. Lowe has been Vice President—Marketing of the Company since December 1997. He was General Manager—Marketing of the Company from July 1992 to December 1997. He was President of Quasar Energy, Inc. from November 1990 to July 1992, providing downstream natural gas marketing services. From September 1983 to November 1990, he was employed by Maxus Energy Corporation, formerly Diamond Shamrock Exploration Company, serving as Manager—Marketing and in various other management and supervisory capacities. From 1981 to September 1983, he was employed by American Quasar Exploration Company as Manager—Oil and Gas Marketing. From 1978 to 1981, he was employed by Texas Pacific Oil Company serving in various positions in production and marketing. He has a B.S. Degree in Education from Texas Tech University.

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

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

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

Mr. Thalken has been Vice President—Acquisitions of the Company since December 1997. He was Acquisitions Technical Manager of the Company from May 1995 to December 1997 and an acquisitions engineer with the Company from January 1992 to May 1995. From October 1990 to December 1991, he was employed by Enron Oil and Gas Company, serving as a production engineer. From May 1983 to September 1990, he was employed by Exxon Company USA, in various engineering and supervisory capacities. He has a B.S. Degree in Mechanical Engineering from the University of Kansas.

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

## PART II

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

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

| | High | Low | Dividends Paid |
|---|---|---|---|
| **2002** | | | |
| First Quarter | $ 14.70 | $ 7.85 | $ .035 |
| Second Quarter | 14.96 | 10.61 | .035 |
| Third Quarter | 11.80 | 8.10 | .040 |
| Fourth Quarter | 11.50 | 8.32 | .040 |
| **2001** | | | |
| First Quarter | $ 22.81 | $ 18.44 | $ .030 |
| Second Quarter | 22.20 | 18.02 | .030 |
| Third Quarter | 20.25 | 14.75 | .035 |
| Fourth Quarter | 18.95 | 11.77 | .035 |

Substantially all of the Company's stockholders maintain their shares in "street name" accounts and are not, individually, stockholders of record. As of December 31, 2002, the common stock was held by 214 holders of record and approximately 16,500 beneficial owners.

The Company began paying a quarterly cash dividend in the fourth quarter of 1992 and 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, the Company suspended its regular quarterly cash dividend for the remainder of 1999. The Company re-instituted the payment of dividends beginning in the first quarter of 2000 with a $.025 per share cash dividend and expects to continue paying a regular quarterly cash dividend. However, subject to restrictions under credit arrangements, the determination of the amount of future cash dividends, if any, to be declared and paid, will depend on, among other things, the Company's financial condition, funds from operations, the level of its capital expenditures and its future business prospects. The Company's credit arrangements (including the indentures for its outstanding senior and senior subordinated indebtedness) contain certain restrictions on the payment of cash dividends. The Company is prohibited from paying cash dividends if the Company's Consolidated Interest Coverage Ratio (as defined in indentures) does not exceed 2.5 to 1.0. The Company is also prohibited from paying cash dividends if such payments would reduce Net Worth (as defined in the Company's revolving credit facility) below the sum of $425 million plus 75 percent of net proceeds of any equity offerings subsequent to May 2, 2002, less any impairment writedowns required by GAAP or by the Securities and Exchange Commission and excluding any impact related to SFAS No. 133. Net Worth (as defined) was approximately $535 million at December 31, 2002.

Item 6. Selected Financial Data.

SELECTED FINANCIAL AND OPERATING DATA

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2002 | 2001 | 2000 | 1999 | 1998 |
| | (In thousands, except per share amounts and operating data) | | | | |
| **Income Statement Data:** | | | | | |
| Oil and gas sales | $ 577,699 | $ 707,090 | $ 649,736 | $ 366,608 | $ 269,681 |
| Gas marketing revenues | 66,516 | 130,209 | 128,836 | 60,275 | 54,108 |
| Oil and gas gathering and processing revenues | 5,731 | 17,032 | 19,998 | 6,955 | 7,741 |
| Total revenues | 664,263 | 884,967 | 775,380 | 492,561 | 332,753 |
| Operating expenses | 276,700 | 348,782 | 294,361 | 182,088 | 184,577 |
| Exploration costs | 42,734 | 21,587 | 22,677 | 14,684 | 23,661 |
| Depreciation, depletion and amortization | 178,902 | 165,984 | 98,042 | 106,484 | 108,865 |
| Impairment of oil and gas properties | 98,720 | 29,050 | 225 | 3,306 | 70,913 |
| Amortization of goodwill | - | 11,940 | - | - | - |
| Impairment of goodwill | 76,351 | - | - | - | - |
| Interest | 77,714 | 64,720 | 48,437 | 58,634 | 43,680 |
| Loss on early extinguishment of debt | 8,154 | - | - | - | - |
| Income (loss) from continuing operations before cumulative effect of changes in accounting principles | (105,222) | 126,449 | 171,486 | 67,661 | (87,311) |
| Income (loss) from discontinued operations, net of income taxes | 22,105 | 7,058 | 25,421 | 5,710 | (354) |
| Income (loss) before cumulative effect of changes in accounting principles | (83,117) | 133,507 | 196,907 | 73,371 | (87,665) |
| Net income (loss) | (143,664) | 133,507 | 195,893 | 73,371 | (87,665) |
| Income (loss) per share from continuing operations before cumulative effect of changes in accounting principles: | | | | | |
| Basic | (1.66) | 2.01 | 2.74 | 1.17 | (1.68) |
| Diluted | (1.66) | 1.98 | 2.68 | 1.14 | (1.68) |
| Income (loss) per share before cumulative effect of changes in accounting principles: | | | | | |
| Basic | (1.31) | 2.12 | 3.15 | 1.27 | (1.69) |
| Diluted | (1.31) | 2.09 | 3.08 | 1.24 | (1.69) |
| Income (loss) per share: | | | | | |
| Basic | (2.27) | 2.12 | 3.13 | 1.27 | (1.69) |
| Diluted | (2.27) | 2.09 | 3.06 | 1.24 | (1.69) |
| Dividends declared per share | .16 | .14 | .14 | - | .09 |
| **Balance Sheet Data (end of year):** | | | | | |
| Total assets | $ 1,775,804 | $ 2,107,902 | $ 1,352,002 | $ 1,168,454 | $ 1,016,472 |
| Long-term debt | 883,180 | 1,010,673 | 464,229 | 625,318 | 672,507 |
| Stockholders' equity | 570,992 | 729,443 | 624,857 | 431,129 | 273,958 |

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2002 | 2001 | 2000 | 1999 | 1998 |
| | (In thousands, except per share amounts and operating data) | | | | |
| **Operating Data:** | | | | | |
| **Production:** | | | | | |
| Oil (MBbls) | 20,859 | 21,974 | 19,861 | 16,877 | 16,434 |
| Gas (MMcf) | 69,846 | 75,641 | 53,729 | 48,354 | 47,238 |
| **Average Sales Prices:** | | | | | |
| Oil (per Bbl) | $ 21.27 | $ 21.93 | $ 25.55 | $ 16.92 | $ 11.06 |
| Gas (per Mcf) | 2.26 | 3.30 | 3.22 | 1.89 | 1.87 |
| **Proved Reserves (end of year):** | | | | | |
| Oil (MBbls) | 348,697 | 332,261 | 318,560 | 303,190 | 164,457 |
| Gas (MMcf) | 1,083,546 | 1,216,724 | 1,023,208 | 988,989 | 806,833 |
| Total proved reserves (MBOE) | 529,288 | 535,048 | 489,095 | 468,022 | 298,929 |
| Present value of estimated future net revenues before income taxes discounted at 10 percent (in thousands) | $4,009,322 | $1,914,073 | $4,338,616 | $2,989,626 | $ 703,211 |
| Standardized measure of discounted future net cash flows (in thousands) | 2,746,257 | 1,438,141 | 2,951,121 | 2,247,237 | 648,222 |

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

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

**Results of Operations**

The Company's results of operations have been significantly affected by its success in acquiring oil and gas properties and its ability to maintain or increase production through its exploitation and exploration activities. Significant acquisitions and dispositions of producing oil and gas properties during 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 the Company's results. The following tables reflect the Company's oil and gas production and its average oil and gas prices for the periods presented:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| **Production:** | | | |
| Oil (MBbls) - | | | |
| U.S. | 6,796 | 8,409 | 9,044 |
| Canada | 1,829 | 1,539 | 19 |
| Argentina (a) | 10,942 | 10,548 | 9,406 |
| Bolivia (b) | 118 | 101 | 131 |
| Continuing operations | 19,685 | 20,597 | 18,600 |
| Ecuador (c) | 1,174 | 1,375 | 1,261 |
| Trinidad | - | 2 | - |
| Total | 20,859 | 21,974 | 19,861 |
| Gas (MMcf) - | | | |
| U.S. | 24,841 | 34,168 | 35,764 |
| Canada | 29,951 | 22,132 | 312 |
| Argentina | 8,630 | 10,253 | 8,705 |
| Bolivia | 6,424 | 9,088 | 8,948 |
| Total | 69,846 | 75,641 | 53,729 |
| MBOE from continuing operations | 31,326 | 33,204 | 27,555 |
| Total MBOE | 32,500 | 34,581 | 28,816 |

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

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

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| **Average Sales Price (including impact of hedges):** | | | |
| Oil (per Bbl) - | | | |
| U.S. | $ 21.78 | $ 23.08 | $ 22.85 |
| Canada | 21.62 | 20.55 | 26.05 |
| Argentina | 20.98(a) | 21.80 | 28.25 |
| Bolivia | 20.73 | 20.06 | 29.62 |
| Continuing operations | 21.31(a) | 22.22 | 25.63 |
| Ecuador | 20.46 | 17.65 | 24.27 |
| Total | 21.27(a) | 21.93 | 25.55 |
| Gas (per Mcf) - | | | |
| U.S. | $ 2.85 | $ 4.83 | $ 3.91 |
| Canada | 2.48 | 2.50 | 5.73 |
| Argentina | .37 | 1.30 | 1.79 |
| Bolivia | 1.54 | 1.72 | 1.75 |
| Total | 2.26 | 3.30 | 3.22 |
| **Average Sales Price (excluding impact of hedges):** | | | |
| Oil (per Bbl) - | | | |
| U.S. | $ 22.66 | $ 22.17 | $ 26.95 |
| Canada | 21.62 | 20.55 | 26.05 |
| Argentina | 21.06(a) | 20.66 | 28.25 |
| Bolivia | 20.73 | 20.06 | 29.62 |
| Continuing operations | 21.66(a) | 21.27 | 27.62 |
| Ecuador | 20.46 | 17.65 | 24.27 |
| Total | 21.60(a) | 21.04 | 27.41 |
| Gas (per Mcf) - | | | |
| U.S. | $ 2.94 | $ 4.83 | $ 3.91 |
| Canada | 2.49 | 2.50 | 5.73 |
| Argentina | .37 | 1.30 | 1.79 |
| Bolivia | 1.54 | 1.72 | 1.75 |
| Total | 2.30 | 3.30 | 3.22 |

(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 $.73, $.41 and $.38, respectively.

**Oil Prices**

Average U.S. and Canada oil prices received by the Company fluctuate generally with changes in the NYMEX reference price for oil. The Company's oil production in Argentina and Ecuador 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 2002, the Company experienced a three percent decrease in its average oil price, including the impact of hedging activities (three percent increase excluding hedging activities), compared to 2001. The Company experienced a 14 percent decrease in its average oil price, including the impact of hedging activities (23 percent decrease excluding hedging activities) in 2001 compared to 2000. The Company's realized average oil price for 2002 (before hedges) was approximately 83 percent of the NYMEX reference price, compared to 81 percent in 2001 and 91 percent in 2000.

As discussed in Note 1 to the Company's 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 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 and is included in lease operating expenses in the Company's statements of operations. The tax is limited by law to a term of no more than 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.

The Company currently exports approximately 70 percent of its Argentine oil production. The Company believes that this export tax will have the effect of decreasing all future Argentine oil revenues (not only export revenues) by the tax rate for the duration of the tax. The U.S. dollar equivalent value for domestic Argentine oil sales (now paid in pesos) has generally moved to parity with the U.S. dollar-denominated export values, net of the export tax. The adverse impact of this tax has been partially offset by the net cost savings 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.

The Company participated in oil hedges covering 4.9 MMBbls, 5.5 MMBbls and 9.3 MMBbls in 2002, 2001 and 2000, respectively. The impacts of these oil hedges on the Company's average oil prices are reflected in the preceding tables.

**Gas Prices**

Average U.S. gas prices received by the Company fluctuate generally 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. The Company's gas in Canada is generally sold at spot market prices as reflected by the AECO gas price index. Most of the Company's Bolivian gas production is sold at average gas prices tied to a long-term contract under which the base price is adjusted for changes in specified fuel oil indexes. The Company's Argentine gas is sold under spot contracts of varying lengths, 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. The Company's total average gas price for 2002 was 32 percent lower than 2001, including the impact of hedging activities (30 percent lower excluding hedging activities), and for 2001 was two percent higher than for 2000.

The Company participated in gas hedges covering 13.5 million MMBtu in 2002. The impacts of these gas hedges on the Company's average gas prices are reflected in the preceding tables. The Company did not participate in any gas hedges in 2001 or 2000.

## Future Period Hedges

The Company has previously engaged in oil and gas hedging activities and intends to continue to consider various hedging arrangements to realize commodity prices which it considers favorable. The Company has entered into various oil hedges (swap agreements) covering approximately 4.1 MMBbls at a weighted average price of $26.26 per Bbl (NYMEX reference price) for various periods in 2003. The Company has also entered into various gas hedges (swap agreements) covering approximately 20.1 million MMBtu of its gas production for calendar year 2003. The Canadian portion of the gas swap agreements (approximately 9.1 million MMBtu) is at an average NYMEX reference price of 6.63 Canadian dollars per MMBtu and will be settled in Canadian dollars. The U.S. portion of the gas swap agreements (approximately 11 million MMBtu) is at an average NYMEX reference price of $4.00 per MMBtu. Additionally, the Company has entered into basis swap agreements for approximately 8.4 million MMBtu of its U.S. gas production covered by the gas swap agreements. These basis swaps establish a differential between the NYMEX reference price and the various delivery points at levels that are comparable to the historical differentials received by the Company. For additional information, see "Items 1 and 2. Business and Properties - Marketing" included elsewhere in this Form 10-K.

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

Relatively modest changes in either oil or gas prices significantly impact the Company's results of operations and cash flows. However, the impact of changes in the market prices for oil and gas on the Company's average realized prices may be reduced from time to time based on the level of the Company's hedging activities. Based on 2002 oil production from continuing operations, a change in the average oil price realized, before hedges, by the Company of $1.00 per Bbl would result in a change in net income and cash flows before income taxes on an annual basis of approximately $13.4 million and $21.2 million, respectively. A 10 cent per Mcf change in the average gas price realized, before hedges, by the Company would result in a change in net income and cash flows before income taxes on an annual basis of approximately $4.2 million and $6.9 million, respectively, based on 2002 gas production from continuing operations.

## Period to Period Comparisons

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

The Company made two acquisitions in Canada (the "Canadian Acquisitions"), which include the purchase of 100 percent of the outstanding common stock of Cometra Energy (Canada) Ltd. ("Cometra") in December 2000 and the purchase of 100 percent of the outstanding common stock of Genesis Exploration Ltd. ("Genesis") in May 2001. The Company's consolidated revenues and expenses for the year ended December 31, 2000, include, under the purchase method of accounting, the consolidation of the revenues and expenses of Cometra for December 2000. The Company's 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, 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, subject to post-closing adjustments. In accordance with the rules established by Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, the Company's operations in Trinidad, along with the gain on the sale, and the Company's operations in Ecuador are accounted for as discontinued operations in the Company's consolidated financial statements. ***Accordingly, the revenues and operating expenses discussed below exclude the results related to the Company's operations in Ecuador and Trinidad for all periods.***

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

The Company 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 year ended December 31, 2002 included $22.1 million in income from discontinued operations related to the Company's operations in Trinidad and Ecuador compared to $7.1 million in income from discontinued operations for the year ended December 31, 2001. Non-cash charges totaling $194.6 million, after tax, for the impairments of both goodwill and oil and gas properties and the impact of the cumulative effect of an accounting change, nearly all of which related to the Company's Canadian operations, were the primary factors in the net loss. 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.

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 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 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 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, 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 heavy oil properties in the Santa Maria area of southern California in June 2002. Included in the gain is the reversal of the Company's accrual for future abandonment costs related to these properties. In 2001, the Company recorded a gain on disposition of assets of $26.9 million ($16.7 million net of tax).

As discussed in Note 1 to the Company's 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 (included in "Other income (expense)" on the statement of operations) 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 ended December 31, 2002, resulted in a foreign currency exchange gain of $0.3 million. The Company 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.

Lease operating expenses, including production and export taxes, of $204.3 million for 2002 were relatively even with the $204.7 million for 2001. However, before the $24.8 million impact of the tax imposed in 2002 on Argentine oil exports, lease operating expense per BOE decreased seven percent to $5.73, compared to $6.16 in 2001, primarily as a result of the beneficial impact of the Argentine peso devaluation on peso-denominated costs.

Exploration costs increased $21.1 million (98 percent), to $42.7 million for 2002 from $21.6 million for 2001. During 2002, the Company's 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.

Impairments of oil and gas properties of $98.7 million ($57.7 million net of tax) were recognized 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 Canadian properties in the fourth quarter of 2002. The Company reviews its proved properties for impairment on a field basis and recognizes 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 the Company's 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"). In estimating the future net revenues, the Company assumed that current oil prices would return to more historical levels over a short period of time and that current gas prices would remain at the levels experienced in recent years. The Company assumed that operating costs would escalate annually beginning at current levels. Due to the volatility of oil and gas prices, it is possible that the Company's assumptions regarding oil and gas prices may change in the future. If future price expectations are reduced, it is possible that additional significant impairment provisions for oil and gas properties would be required. Also, the economic instability in Argentina could cause economic conditions that would result in future significant impairments for the Company's Argentine oil and gas properties.

General and administrative expenses increased $1.2 million (two percent), to $49.3 million for 2002 from $48.1 million for 2001. Expenses increased in the United States due to increases in non-cash charges for amortization of restricted stock awards and increases in Canada as a result of having a full year of operations for Genesis in 2002 compared to only eight months in 2001. These increases 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 $1.57 for 2002 from $1.45 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 the Company's 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 the Company's average interest rate to 7.50 percent in 2002 as compared to 7.58 percent in 2001.

In conjunction with the issuance of the Company's 8 1/4% senior notes, the Company entered into a new revolving credit facility and redeemed a portion of the Company's 9% senior subordinated notes. 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% senior subordinated notes, resulted in a one-time charge of approximately $8.2 million ($5.0 million net of tax) in 2002.

Effective January 1, 2002, the Company adopted the provisions of Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* ("SFAS No. 142"). SFAS No. 142 changes the accounting for goodwill from an amortization method to an impairment-only method. Under SFAS No. 142, all goodwill amortization ceased effective January 1, 2002. Goodwill was tested for impairment in conjunction with a transitional goodwill impairment test in 2002 and will be tested at least annually thereafter. As a result of the transitional impairment test, the Company recorded a $60.5 million charge to "Cumulative effect of change in accounting principle" retroactive to January 1, 2002, in accordance with the provisions of SFAS No. 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 the Company's 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 test as of December 31, 2002, resulted in an additional $76.4 million charge. Certain downward revisions recorded to the Company's Canadian oil and gas reserves in the fourth quarter of 2002 were the primary reason for the additional impairment at December 31, 2002. These downward revisions resulted from additional geological, geophysical and engineering information and from revised production projections.

*Year Ended December 31, 2001 Compared to Year Ended December 31, 2000*

The Company reported net income of $133.5 million for the year ended December 31, 2001, compared to net income of $195.9 million for the same period in 2000. The year ended December 31, 2001, included $7.1 million in income from discontinued operations related to the Company's operations in Trinidad and Ecuador compared to $25.4 million in income from discontinued operations for the year ended December 31, 2000. An increase in the Company's oil and gas production from continuing operations of 21 percent on an equivalent barrel basis was substantially offset by a 13 percent reduction in average oil prices and higher charges for depreciation, depletion and amortization of oil and gas properties and goodwill. Net income for 2001 included a $17.9 million after-tax loss due to the impairment of oil and gas properties, a $16.7 million after-tax gain on sales of non-strategic properties and a $3.3 million after-tax gain due to the devaluation of the Argentine peso in December 2001. Net income for 2000 included a $16.3 million after-tax non-recurring charge due to an adverse judgment from litigation, a $1.1 million after-tax loss on sales of non-strategic properties and a $1.0 million after-tax loss due to a change in accounting principle.

Oil and gas sales increased $57.4 million (nine percent), to $707.1 million for 2001 from $649.7 million for 2000. A 41 percent increase in gas production, combined with a two percent increase in average gas prices, accounted for a $76.4 million increase in gas sales for 2001 as compared to 2000. A 13 percent decrease in average oil prices more than offset an 11 percent increase in oil production and accounted for a $19.0 million decrease in oil sales for 2001 as compared to 2000. The 11 percent increase in oil production and the 41 percent increase in gas production are primarily the result of the Canadian Acquisitions and the Company's exploitation and exploration activities, partially offset by declines in U.S. production.

A gain on disposition of assets of $26.9 million ($16.7 million net of tax) was reflected in 2001 as a result of $47.1 million in proceeds from divestitures of non-strategic oil and gas properties in the United States. In 2000, the Company recorded a loss on disposition of assets of $1.7 million ($1.1 million net of tax). Other than the gain recorded, the 2001 divestitures did not significantly affect the Company's 2001 results of operations as the majority of the divestitures occurred in the fourth quarter of 2001.

As discussed in Note 1 to the Company's 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 (included in "Other income (expense)" on the statement of operations) and approximately $1.0 million in reductions of certain operating expenses. There was no such gain in 2000.

As a result of an unfavorable decision by the Supreme Court of Argentina, the Company had recorded as other expense in 2000 a non-recurring charge of $25.1 million ($16.3 million net of tax). No similar charge was incurred in 2001.

Lease operating expenses, including production taxes, increased $51.2 million (33 percent), to $204.7 million for 2001 from $153.5 million for 2000 primarily due to the 21 percent increase in total production from continuing operations, increased lease power and fuels costs, higher costs for oilfield services and certain one-time repair costs in the U.S. Lease operating expenses per equivalent barrel produced increased 11 percent to $6.16 in 2001 from $5.57 in 2000.

Exploration costs decreased $1.1 million (five percent), to $21.6 million for 2001 from $22.7 million for 2000. During 2001, the Company's exploration costs 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. Exploration costs for 2000 included $19.1 million for unsuccessful exploratory drilling, primarily in Bolivia, $2.9 million for leasehold impairments and $0.7 million for other geological and geophysical costs.

Impairments of oil and gas properties of $29.1 million ($17.9 million net of tax) were recognized in 2001, compared to $0.2 million of impairments in 2000, due primarily to oil and gas reserve revisions on certain Canadian and U.S. properties in 2001.

General and administrative expenses increased $8.3 million (21 percent), to $48.1 million for 2001 from $39.8 million for 2000 due primarily to costs associated with the Canadian operations acquired through the Canadian Acquisitions and personnel additions and consulting costs in conjunction with the Company's higher level of capital expenditures. General and administrative expenses per equivalent barrel produced increased by eight percent to $1.45 for 2001 from $1.34 for 2000.

Depreciation, depletion and amortization increased $68.0 million (69 percent), to $166.0 million for 2001 from $98.0 million for 2000, due primarily to the 21 percent increase in production on an equivalent barrel basis and a 43 percent increase in the average amortization rate per equivalent barrel produced from $3.41 in 2000 to $4.86 in 2001 primarily due to the acquisition of Genesis.

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the purchase of Genesis. In 2001, goodwill was amortized using the unit-of-production basis over the total proved reserves acquired and totaled approximately $11.9 million. There was no goodwill amortization recorded in 2000.

Interest expense increased $16.3 million (34 percent), to $64.7 million for 2001 from $48.4 million for 2000, due primarily to a 60 percent increase in the Company's total average outstanding debt year over year, primarily due to the Canadian Acquisitions. This increase was partially offset as the Company's overall average interest rate decreased to 7.58 percent in 2001 as compared to 8.87 percent in 2000. This reduction resulted from lower rates on its floating-rate debt due to overall market reductions and a significant increase in its level of lower-cost floating-rate borrowings versus fixed-rate debt.

Capital Expenditures

During 2002, the Company's total oil and gas capital expenditures were $129.7 million ($117.5 million on continuing operations). In North America, the Company's oil and gas capital expenditures totaled $88.1 million. Exploration activities accounted for $37.6 million of the North America capital expenditures with exploitation activities contributing $45.8 million. The Company also spent $4.7 million on the acquisition of North American unproved acreage in 2002. During 2002, the Company's international oil and gas capital expenditures totaled $41.6 million. This amount consists of exploitation activities of $19.0 million in Argentina, $12.2 million in Ecuador and $2.6 million in Bolivia and exploration activities of $7.8 million, primarily in Yemen.

As of December 31, 2002, the Company had total unproved oil and gas property costs of approximately $88.0 million consisting of undeveloped leasehold costs of $76.0 million, including $56.3 million in Canada, and unevaluated exploratory drilling of $12.0 million. Approximately $15.9 million of the total unproved costs are associated with the Company's drilling program in Yemen. Future exploration expense and earnings may be impacted to the extent any of the exploratory drilling is determined to be unsuccessful.

On May 2, 2001, the Company 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 the Company's revolving credit facility and cash on hand.

The timing of most of the Company's capital expenditures is discretionary with no material long-term capital expenditure commitments. Consequently, the Company has a significant degree of flexibility to adjust the level of such expenditures as circumstances warrant. The Company uses internally-generated cash flows to fund capital expenditures other than significant acquisitions. The Company's capital expenditure budget for 2003 is currently set at $185 million, exclusive of acquisitions. The Company does not have a specific acquisition budget since the timing and size of acquisitions are difficult to forecast. The Company is actively pursuing additional acquisitions of oil and gas properties. In addition to internally-generated cash flows and advances under its revolving credit facility, the Company 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 the Company's desired acquisitions.

The Company's recent capital expenditure history is as follows:

| (In thousands) | Years Ended December 31, 2002 | 2001 | 2000 |
|---|---|---|---|
| Acquisition of oil and gas reserves | $ - | $ 607,217 | $ 91,448 |
| Drilling | 82,664 | 135,620 | 121,911 |
| Acquisition of undeveloped acreage and seismic | 19,592 | 85,489 | 18,084 |
| Workovers and recompletions | 24,673 | 62,038 | 25,811 |
| Other | 2,777 | 1,024 | 419 |
| Oil and gas capital expenditures | 129,706 | 891,388 | 257,673 |
| Gathering system and plant projects | 4,554 | 1,256 | 299 |
| Total | $ 134,260 | $ 892,644 | $ 257,972 |

**Capital Resources and Liquidity**

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

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

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.

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% Senior Subordinated Notes due 2005 (the "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, prior to 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.

In conjunction with the offering of the 8 1/4% Notes, the Company entered into a new $300 million revolving credit facility (as amended, the "Bank Facility"), which was used to refinance its previously existing credit facility and to provide funds for ongoing operating and general corporate needs. The Company also redeemed a portion of the 9% Notes. As a result, 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) recorded in the second quarter of 2002.

During the first quarter of 2003, the Company advanced funds under the Bank Facility to redeem the remainder of the 9% Notes due 2005. As a result, the Company was required to expense certain associated deferred financing costs and discounts. This $1.0 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 $1.7 million ($1.0 million net of tax) which will be recorded in the first quarter of 2003.

The Bank Facility consists of a three-year senior secured credit facility with availability governed by a borrowing base determination. The Company's availability under the Bank Facility is reduced by the outstanding letters of credit. The borrowing base (currently $300 million) is 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 redetermination will be in April 2003. 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.

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 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 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. As of December 31, 2002, the Company had $33.8 million outstanding under its Bank Facility, excluding outstanding letters of credit of approximately $15.9 million, at an average interest rate of approximately 3.28 percent. A portion of the proceeds from the January 31, 2003, sale of the Company's operations in Ecuador was used to repay the entire outstanding balance under the Bank Facility. As a result, at February 28, 2003, the unused availability under the Bank Facility (considering outstanding letters of credit of approximately $15.9 million) was approximately $284 million.

The terms of the Bank Facility require the maintenance of a minimum current ratio (as defined therein) and tangible net worth (as defined therein) of not less than $425 million plus 75 percent of the net proceeds of any future equity offerings less any impairment write downs required by GAAP or by the Securities and Exchange Commission and excluding any impact related to SFAS No. 133.

The Company's internally generated cash flows, results of operations and financing for its operations are dependent on oil and gas prices. Realized oil and gas prices for the year decreased by four percent and 32 percent, respectively, as compared to 2001. For 2002, approximately 63 percent of the Company's production was oil. The Company believes that its cash flows and unused availability under the Bank Facility are sufficient to fund its planned capital expenditures for the foreseeable future. To the extent oil and gas prices decline, the Company's earnings and cash flows from operations may be adversely impacted. Prolonged periods of low oil and gas prices could cause the Company to not be in compliance with maintenance covenants under its Bank Facility and could negatively affect its credit statistics and coverage ratios and thereby affect its liquidity.

Consistent with its stated goal of maintaining financial flexibility and optimizing its portfolio of assets, the Company announced in early 2002 plans to reduce debt by $200 million through a combination of asset sales and cash flows in excess of planned capital expenditures. The Company determined that the level of investment and time horizon required to continue the development of its interests in Ecuador and Trinidad were inconsistent with the timing of its desire to reduce leverage. These assets, along with the Company's remaining heavy oil properties in the Santa Maria area of southern California, were identified for sale. The Company's heavy oil properties in the Santa Maria area of southern California were sold in June 2002 for $9.5 million in cash and a note receivable for $6 million bearing monthly payments of $360,000, plus interest, with final maturity in June 2003. The Company received a cash payment as final settlement of this note in October 2002. The Company's interest in Trinidad was sold in July 2002 for $40 million in cash and the Company's interest in Ecuador was sold in January 2003 for $137.4 million in cash, subject to post-closing adjustments. The closing of the sale of its interest in Ecuador culminated the achievement of the Company's $200 million debt reduction goal. After giving pro forma effect to the estimated after-tax proceeds from the sale of its operations in Ecuador, the Company's net debt at December 31, 2002, would be approximately $775 million. This compares to net debt at December 31, 2001, of approximately $1.0 billion. The Company is considering additional debt reduction in 2003 to continue its progress toward lower debt levels. Currently, the Company anticipates that any such de-leveraging would be funded by additional sales of non-strategic assets.

**Off Balance Sheet Arrangements and Contractual Obligations**

The Company has no off balance sheet arrangements, as defined by SEC rules. A summary of the Company's contractual obligations as of December 31, 2002, is as follows (in thousands):

| | Payments Due By Year | | | | | | |
|---|---|---|---|---|---|---|---|
| | Total | 2003 | 2004 | 2005 | 2006 | 2007 | Thereafter |
| Long-term debt (a) | $ 883,800 | $ - | $ - | $ 83,800(b) | $ - | $ - | $ 800,000 |
| Operating leases (c) | 15,439 | 3,386 | 3,362 | 4,876 | 2,480 | 1,001 | 334 |
| Bolivia work unit commitments (c) | 6,300 | 6,300 | - | - | - | - | - |
| Firm transportation and compression agreements (c) | 5,558 | 2,686 | 1,396 | 328 | 285 | 267 | 596 |
| Other long-term obligations | 486 | - | - | - | - | - | 486 |
| | $ 911,583 | $ 12,372 | $ 4,758 | $ 89,004 | $ 2,765 | $ 1,268 | $ 801,416 |

(a) See Note 2 "Long-term Debt" to the Company's consolidated financial statements included elsewhere in this Form 10-K.

(b) This amount was repaid in 2003.

(c) See Note 5 "Commitments and Contingencies" to the Company's consolidated financial statements included elsewhere in this Form 10-K.

The Company has no capital leases. The above table does not include $15.9 million of letters of credit that have been issued by commercial banks on the Company's behalf which, if funded, would become borrowings under the Company's revolving credit facility. The $883.8 million of long-term debt shown in the table excludes $0.6 million of discounts, which are included in the amount shown on the Company's December 31, 2002, 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 recent devaluation of the Argentine peso, 2002 peso inflation was approximately 41 percent in Argentina. However, in recent months, the Argentine inflation rate has slowed significantly, with the inflation rate for the month of January 2003 at 1.3 percent. In recent years inflation outside of Argentina has not had a significant impact on the Company's operations or financial condition and is not currently expected to have a significant impact on future periods.

**Income Taxes**

The Company incurred a current provision for income taxes of $21.7 million, $80.5 million and $68.9 million for 2002, 2001 and 2000, 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 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 fully utilized its U.S. federal regular income tax net operating loss ("NOL") carryforward and its U.S. federal alternative minimum tax credit carryforward in 2000. The Company generated a U.S. federal regular income tax NOL in 2002, which it intends to carry back against prior year taxable income in order to receive a refund of taxes previously paid. The Company also has 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. The Company has a Bolivian income tax NOL carryforward of approximately $55 million that does not expire. The Company also has an Argentine income tax NOL at December 31, 2002, of approximately 59 million pesos ($17 million) in its subsidiary, Vintage Petroleum Argentina S.A., that expires in varying annual amounts over a four-year period beginning in 2003 and can be used to offset future income tax liabilities. The Company expects to fully utilize the entire remaining Argentine NOL carryforward in 2003. Additionally, the Company also has a Canadian income tax NOL carryforward of approximately C$17 million ($11 million), approximately 75 percent of which will expire in 2008 with the balance expiring in 2009. The Company expects to fully utilize this entire NOL carryforward prior to its expiration.

**Critical Accounting Policies and Estimates**

Management's discussion and analysis of its financial condition and results of operations are based upon the Company's 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. The Company bases its 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 the Company's consolidated financial statements included elsewhere in this Form 10-K, contains a comprehensive summary of the Company's significant accounting policies. The following is a discussion of the Company's most critical accounting policies, judgments and uncertainties that are inherent in the Company's application of GAAP:

*Accounting for 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 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. The Company recognizes gains or losses on the sale of properties on a field basis.

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 the Company enters 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.

*Proved reserve estimates.* Estimates of the Company's proved reserves included in its 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 geologic, geophysic, 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.

The Company's proved reserve information is based on estimates prepared by its 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 the Company's 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 the Company records 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. In addition, the decline in proved reserve estimates may impact the outcome of the Company's assessment of its oil and gas producing properties and goodwill for impairment.

*Impairment of proved oil and gas properties.* 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. 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 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 the Company to record an impairment of its oil and gas properties and there can be no assurance that such impairments will not be required in the future.

*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. Management's assessment of the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such leaseholds impact 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, 2002, the Company had total unproved oil and gas property costs of approximately $88.0 million consisting of undeveloped leasehold costs of $76.0 million, including $56.3 million in Canada, and unevaluated exploratory drilling costs of $12.0 million. Approximately $15.9 million of the total unevaluated costs are associated with the Company's drilling program in Yemen.

*Impairment of goodwill.* The Company's goodwill of $21.1 million at December 31, 2002, is entirely related to its Canadian operations. The Company must assess its goodwill for impairment at least annually. The Company must perform an initial assessment of whether there is an indication that the carrying value of goodwill is impaired. This assessment is made by comparing the fair value of the Canadian operations, as determined in accordance with SFAS No. 142, to the book value. If the fair value is less than the book value, an impairment is indicated and the Company must perform a second test to measure the amount of the impairment. In the second test, the Company must then calculate 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. If the carrying value of the goodwill exceeds this calculated implied fair value of the goodwill, an impairment charge is recorded.

*Estimates of future dismantlement, restoration, and abandonment costs.* Through December 31, 2002, the Company had accrued future abandonment costs of wells and related facilities through its 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* and industry practice. The accounting for future development and abandonment costs changed on January 1, 2003, with the adoption of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations.* See "New Accounting Pronouncements" 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 the Company's 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 upon numerous factors, including changing technology and the political and regulatory environment and, beginning in 2003, estimates as to the proper discount rate to use and timing of abandonment.

*Income taxes.* The Company provides deferred income taxes on transactions which are recognized in different periods for financial and tax reporting purposes. The Company has not recognized a U.S. deferred tax liability related to the unremitted earnings of any of its foreign subsidiaries as it is the Company's intention, generally, to reinvest such earnings permanently. Management periodically assesses the need to utilize these unremitted earnings to finance the operations of the Company. 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 the Company's operations. Such estimates are inherently imprecise since many assumptions utilized in the cash flow projections are subject to revision in the future.

The Company has also recorded deferred tax assets related to operating loss and tax credit carryforwards. Management periodically assesses the probability of recovery of recorded deferred tax assets based on its assessment of future earnings outlooks by tax jurisdiction. Such estimates 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 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. Management determines the functional currencies of the Company's 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 the Company's operations Argentina reflect management's assumptions regarding uncertainties unique to Argentina's current economic situation. See Note 1 to the Company's 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 the Company receives for oil and gas it produces and sells; (ii) the timing and amount of repatriations of cash to the U.S.; (iii) the amount of permitted export sales; (iv) the Argentine banking system; (v) the Company's asset valuations; and (vi) peso-denominated monetary assets and liabilities. 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 Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended in June 1999 by Statement No. 137, *Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB Statement No. 133* and in June 2000 by Statement No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities - an amendment of FASB Statement No. 133* ("SFAS No. 133"). SFAS No. 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 No. 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 No. 133 on January 1, 2001, the Company 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 the Company's forecasted oil production. Additionally, the Company 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 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.

On July 20, 2001, the FASB issued Statement of Financial Accounting Standards No. 141, *Business Combinations* ("SFAS No. 141"), and SFAS No. 142. SFAS No. 141 requires all business combinations initiated after June 30, 2001, to be accounted for using the purchase method of accounting. Under SFAS No. 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.

The Company adopted SFAS No. 141 and SFAS No. 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 the Company's consolidated financial statements included elsewhere in this Form 10-K, 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.

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 No. 144"). SFAS No. 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 No. 144 did not have a material impact on the Company's 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 No. 145"). SFAS No. 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. The Company has adopted the provisions of SFAS No. 145 and, accordingly, has classified an $8.2 million ($5.0 million net of tax) loss on the early extinguishment of debt (see Note 2 to the Company's consolidated financial statements included elsewhere in this Form 10-K) as a charge to income from continuing operations in its statements of operations. The adoption of SFAS No. 145 did not have any other material impact on the Company's financial position or results of operations.

**New Accounting Pronouncements**

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*. The Company was required to adopt this new standard beginning January 1, 2003. Through December 31, 2002, the Company accrued 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 $55.4 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 majority of the asset retirement obligations of the Company relate to the plugging and abandonment of oil and gas wells. However, future abandonment liabilities will also be 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. The liability accretes over time with a charge to accretion expense. At January 1, 2003 there are no assets legally restricted for purposes of settling asset retirement obligations. The Company adopted the new standard effective January 1, 2003, and recorded an increase in property, plant and equipment of approximately $50.4 million, a decrease in accumulated depreciation, depletion and amortization of approximately $44.6 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 $4.4 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 $7.5 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 Company does not expect the adoption of this standard to have a material impact on the Company's financial position or results of operations.

On December 31, 2002, the FASB issued Statement of Financial Accounting Standards No. 148, *Accounting for Stock-Based Compensation - Transition and Disclosure* ("SFAS No. 148"). SFAS No. 148 amends Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation* ("SFAS No. 123"), to provide alternative methods of transition to SFAS No. 123's fair value method of accounting for stock-based employee compensation. SFAS No. 148 also amends the disclosure provisions of SFAS No. 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. While SFAS No. 148 does not amend SFAS No. 123 to require companies to account for employee stock options using the fair value method, the disclosure provisions of the standard are applicable to all companies with stock-based employee compensation, regardless of whether they account for that compensation using the fair value method or the intrinsic value method. The Company adopted the disclosure provisions of SFAS No. 148 in its consolidated financial statements included elsewhere in this Form 10-K. The Company is considering adopting SFAS No. 123's fair value method of accounting for stock-based employee compensation in 2003, but has not yet made a final decision on adoption.

**Foreign Operations**

For information on the Company's 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.**

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

**Commodity Price Risk**

The Company produces, purchases and sells crude oil, natural gas, condensate, natural gas liquids and sulfur. As a result, the Company's 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 2002 production levels. The Company has previously engaged in oil and gas hedging activities and intends to continue to consider various hedging arrangements to realize commodity prices which it considers favorable.

During 2000, the Company entered into oil hedging contracts for various periods in 2000 covering 7.5 MMBbls of oil at a weighted average NYMEX reference price of $27.94. Including hedges entered into in 1999, the Company entered into total oil hedging contracts covering 2000 production of 9.3 MMBbls of oil at a weighted average NYMEX reference price of $26.85 per Bbl. During 2000, the Company entered into various oil hedges (swap agreements) for a total of 3.5 MMBbls of oil at a weighted average NYMEX reference price of $30.71 per Bbl for various periods in 2001. At December 31, 2000, the Company would have received approximately $16.3 million to terminate its oil swap agreements then in place.

During 2001, the Company entered into additional oil hedging contracts for various periods in 2001 covering an additional 1.9 MMBbls of oil at a weighted average NYMEX reference price of $29.28 per Bbl. In total, the Company entered into 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, the Company 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, the Company would have received approximately $4.7 million to terminate its oil swap agreements then in place.

During 2002, the Company 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, the Company 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, the Company entered into various gas price swap agreements covering approximately 11.3 million MMBtu of its 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, the Company entered into costless price collar arrangements for approximately 2.2 million MMBtu of its 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, the Company entered into basis swap agreements covering identical periods of time and volumes. These basis swaps establish a differential between the NYMEX reference price and the various delivery points at levels that are comparable to the historical differentials received by the Company.

During 2002, the Company 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, the Company also entered into various gas hedges (swap agreements) covering approximately 20.1 million MMBtu of its gas production for calendar year 2003 at a weighted average NYMEX reference price of $4.02 per MMBtu. The Canadian portion of the gas swap agreements (approximately 9.1 million MMBtu) is at a weighted average NYMEX reference price of 6.63 Canadian dollars per MMBtu and will be settled in Canadian dollars. The U.S. portion of the gas swap agreements (approximately 11 million MMBtu) is at a weighted average NYMEX reference price of $4.00 per MMBtu. Additionally, the Company has entered into basis swap agreements for approximately 8.4 million MMBtu of its U.S. gas production covered by the gas swap agreements. These basis swaps establish a differential between the NYMEX reference price and the various delivery points at levels that are comparable to the historical differentials received by the Company. At December 31, 2002, the Company would have paid approximately $17.1 million to terminate its swap agreements then in place.

During 2003, the Company entered into additional oil hedging contracts for various periods in 2003 covering an additional 1.1 MMBbls of oil at a weighted average NYMEX reference price of $29.86 per Bbl. In total, the Company has entered into oil hedging contracts covering 2003 oil production of 4.1 MMBbls at a weighted average NYMEX reference price of $26.26 per Bbl.

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

### Interest Rate Risk

The Company's interest rate risk exposure results primarily from short-term rates, mainly LIBOR-based on borrowings from its commercial banks. To reduce the impact of fluctuations in interest rates, the Company maintains a portion of its total debt portfolio in fixed rate debt. At December 31, 2002, the amount of the Company's fixed-rate debt was approximately 96 percent of total debt. In the past, the Company has not entered into financial instruments such as interest rate swaps or interest rate lock agreements. However, it may consider these instruments to manage the portfolio mix between fixed and floating rate debt and to mitigate the impact of changes in interest rates based on management's assessment of future interest rates, volatility of the yield curve and the Company's ability to access the capital markets in a timely manner.

Based on the outstanding borrowings under variable-rate debt instruments at December 31, 2002, a change in the average interest rate of 100 basis points would result in a change in net income and cash flows before income taxes on an annual basis of approximately $0.2 million and $0.3 million, respectively.

The following table provides information about the Company's long-term debt principal payments and weighted-average interest rates by expected maturity dates:

| | 2003 | 2004 | 2005 | 2006 | 2007 | There-after | Total | Fair Value at 12/31/02 |
|---|---|---|---|---|---|---|---|---|
| **Long-term Debt:** | | | | | | | | |
| Fixed-rate (in thousands) . . . . | - | - | $ 50,000 (a) | - | - | $800,000 | $850,000 | $865,674 |
| Average interest rate . . . . . . | - | - | 9.0% | - | - | 8.5% | 8.5% | - |
| Variable-rate (in thousands) . . | - | - | $ 33,800 (a) | - | - | - | $ 33,800 | $ 33,800 |
| Average interest rate . . . . . . | - | - | (b) | - | - | - | (b) | (b) |

(a) These amounts were repaid in 2003.

(b) LIBOR plus an increment, based on the level of outstanding senior debt to the borrowing base, up to a maximum increment of 2.25 percent. Current increment above LIBOR at December 31, 2002, was 1.25 percent.

**Foreign Currency and Operations Risk**

International investments represent, and are expected to continue to represent, a significant portion of the Company's total assets. The Company currently has international operations in Canada, Argentina, Bolivia, Yemen and Italy. For 2002, the Company's operations in Argentina and Canada accounted for approximately 35 percent and 17 percent, respectively, of the Company's revenues and 28 percent and 32 percent, respectively, of the Company's total assets. During 2002, the Company's operations in Argentina and Canada represented its only foreign operations accounting for more than 10 percent of its revenues or total assets. The Company continues to identify and evaluate international opportunities, but currently has no binding agreements or commitments to make any material international investment. As a result of such significant foreign operations, the Company's financial results could be affected by factors such as changes in foreign currency exchange rates, weak economic conditions or changes in the political climate in these foreign countries.

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

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

The Company does not currently maintain political risk insurance. However, the Company will consider obtaining such coverage in the future if it deems conditions so warrant.

*Canada.* With the acquisition of Cometra in December 2000 and the acquisition of Genesis in May 2001, the Company now has significant producing operations in Canada. The Company views the operating environment in Canada as stable and the economic stability as good. Substantially all of the Company's Canadian revenues and costs are denominated in Canadian dollars. While the value of the Canadian dollar does fluctuate in relation to U.S. dollar, the Company believes that any currency risk associated with its Canadian operations would not have a material impact on the Company's financial position or results of operations. The exchange rate at December 31, 2002, was US$1:C$1.58 as compared to US$1:C$1.59 at December 31, 2001.

*Argentina.* Beginning in 1991, Peronist Carlos Menem, as newly-elected President of Argentina, and Domingo Cavallo, as his 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.

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 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.

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, 2002, was 3.38 pesos to one U.S. dollar. The devaluation of the peso reduced the Company's gas revenues and peso-denominated costs. Oil revenues remain valued on a U.S. dollar basis.

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. 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 for 2002 of approximately $8 million, or $.73 per Argentine barrel produced or $.38 per total Company barrel produced. The Company's Argentine lease operating costs were also reduced as a result of this mandate and the positive impact of devaluation on the Company's peso-denominated costs, which essentially offset the negative impact on Argentine oil revenues.

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 Company currently exports approximately 70 percent of its Argentine oil production. The Company believes that this export tax will have the effect of decreasing all future Argentine oil revenues (not only export revenues) by the tax rate for the duration of the tax. The U.S. dollar equivalent value for domestic Argentine oil sales (now paid in pesos) has generally moved to parity with the U.S. dollar denominated export values, net of the export tax. The adverse impact of this tax has been partially offset by the net cost savings resulting from the devaluation of the peso on peso denominated costs and is further reduced by the Argentine income tax savings related to deducting the impact of the export tax. The export tax is not deducted in the calculation of royalty payments.

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 March 3, 2003, of $10.3 billion. The exchange rate has remained stable at or below approximately 3.65 pesos to one U.S. dollar and the February 19, 2003, exchange rate was 3.19 pesos to one U.S. dollar. 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 January 2003 inflation of 1.3 percent. Inflation for all of 2002 was approximately 41 percent.

After a year of negotiations, the International Monetary Fund ("IMF") approved a $6.8 billion dollar debt rollover agreement on January 24, 2003. While only short term in nature, the package is designed to allow stability to continue at least through the presidential election process by rescheduling all IMF debts falling due between January and August of 2003. As part of the agreement, the government agreed to raise its primary budget surplus target to 2.5 percent of the country's gross domestic product.

The plan set in motion by current President Eduardo Duhalde to transition the government back into the hands of an elected president remains in place. General elections are scheduled for April 27, 2003. If necessary a runoff election between the top two candidates will be held during May 2003. President Duhalde has indicated that the transition of government will take place on May 25, 2003, after elections are complete.

On January 2, 2003, at the Argentine government's request, crude oil producers and refiners agreed to cap amounts payable for domestic sales occurring during the first quarter 2003 at $28.50 per Bbl. The producers and refiners further agreed that the difference between the actual price and the capped price would be payable once actual prices fall below the cap. The debt payable under the agreement accrues interest at 8 percent. The total debt will be collected by invoicing future deliveries at $28.50 per Bbl after actual prices fall below the capped price. Additionally, the agreement allowed for renegotiation if the West Texas Intermediate reference price exceeded $35.00 per Bbl for ten consecutive days, which occurred on February 24, 2003.

On February 25, 2003, the agreement between the producers and the refiners was modified to limit the amount payable from refiners to producers for deliveries occurring between February 26, 2003, and March 31, 2003. While the $28.50 per Bbl payable cap was maintained, under the modified terms refiners have no obligation to pay producers for sales values that exceed $36.00 per Bbl. Furthermore, interest for debts established during this period was reduced to seven percent.

The Company expects to sell 500,000 net Bbls of its 2003 Argentine oil production under the original terms of this agreement and 185,000 net Bbls of its 2003 Argentine oil production under the modified terms of this agreement.

*Bolivia.* Since the mid 1980's, Bolivia has been undergoing major economic reform, including the establishment of a free market economy and the encouragement of foreign private investment. Economic activities that had been reserved for government corporations were opened to foreign and domestic Bolivian private investments. Barriers to international trade have been reduced and tariffs lowered. A new investment law and revised codes for mining and the petroleum industry, intended to attract foreign investment, have been introduced.

Elections held during June 2002 marked the sixth consecutive democratic election held 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 Gonzalo Sanchez de Lozada to win the runoff election. Since election, Sanchez de Lozada's government has been working to improve the economic and fiscal framework in order to facilitate new loan agreements from the IMF. After violent protests to his proposed tax increases and cuts in government spending in early 2003, President Sanchez de Lozada was forced to reorganize his government. The government's proposed budget for 2003 has now been withdrawn, and new budget plans will likely be proposed with support from the multilateral lending community.

Also in an attempt to narrow budget deficits, the government has announced new taxes on oil refiners. The oil refiners have, in turn, sued the government. While the final outcome of the newly announced tax on refiners remains unclear, the Company expects to receive lower prices for domestic oil sales as a result of these taxes. In 2002, the Company's Bolivian oil production accounted for less than one percent of the Company's total production from continuing operations on an equivalent barrel basis.

In 1987, the Boliviano replaced the peso at the rate of one million pesos to one Boliviano. 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, 2002, was 7.50 Bolivianos to one U.S. dollar. The Company believes that any currency risk associated with its Bolivian operations would not have a material impact on the Company's financial position or results of operations because its gas revenues are received in U.S. dollars.

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

The Consolidated Financial Statements and notes thereto, the report of independent auditors and the 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.**

On June 27, 2002, upon its review of the recommendation of the Audit Committee of the Board of Directors, the Board of Directors of the Company approved the dismissal of Arthur Andersen LLP as the Company's independent auditors and approved the engagement of Ernst & Young LLP as the Company's independent auditors for its 2002 fiscal year. For additional information, see the Company's Current Report on Form 8-K dated June 27, 2002.

On November 22, 2002, Ernst & Young LLP completed re-audits of the Company's 1999, 2000 and 2001 consolidated financial statements, which were previously audited by Arthur Andersen LLP. For additional information, see the Company's Current Report on Form 8-K dated November 22, 2002.

## PART III

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

The information required by this Item with respect to the Company's Directors is incorporated by reference from the sections of the Company's definitive Proxy Statement for its 2003 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 the Company's Executive Officers appears at Item 4A of Part I of this Form 10-K.

**Item 11. Executive Compensation.**

The information required by this Item is incorporated by reference from the section of the Proxy Statement entitled "Executive Compensation."

**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 the 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, 2002, concerning shares of the Company's common stock authorized for issuance under the Company's 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 | 5,440,736 | $ 14.42 | 511,777(1) |
| Equity compensation plans not approved by security holders | - | - | - |
| Total | 5,440,736 | $ 14.42 | 511,777 |

(1) Represents the total number of shares available for issuance under (a) the Company's 1990 Stock Plan pursuant to stock options, stock appreciation rights or restricted stock or restricted stock rights and (b) the Company's Non-Management Director Stock Option Plan pursuant to stock options. All of the 502,777 shares available for issuance under the Company's 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 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

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

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

**Item 14. Controls and Procedures.**

Within the 90 days prior to the filing date of this Form 10-K, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures, as defined in Rule 13a-14(c) of the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Company's Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its 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. Subsequent to the date of their evaluation, there have been no significant changes in the Company's internal controls or in other factors that could significantly affect these controls.

## PART IV

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

(a) (1) Financial Statements:

The financial statements of the Company and its subsidiaries 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 $.005 per share (Filed as Exhibit 4.1 to the S-1 Registration Statement).

4.2 Indenture dated as of December 20, 1995, between JPMorgan Chase Bank (formerly Chemical Bank), as Trustee, and the Company (Filed as Exhibit 99.1 to the Company's report on Form 8-K filed January 16, 1996).

4.3 Indenture dated as of February 5, 1997, between JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee, and the Company (Filed as Exhibit 4.3 to the Company's report on Form 10-K for the year ended December 31, 1996, filed March 27, 1997).

4.4 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).

4.5 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).

4.6 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).

4.7 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).

4.8 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).

4.9 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* Employment and Noncompetition Agreement dated January 7, 1987, between the Company and Charles C. Stephenson, Jr. (Filed as Exhibit 10.19 to the S-1 Registration Statement).

10.2* 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).

10.3* 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).

10.4* 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).

10.5* 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).

10.6* 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).

10.7* 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).

10.8* 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).

10.9* 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).

10.10* 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")).

10.11* 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).

10.12* 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).

10.13* 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).

10.14* 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).

10.15* 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).

10.16 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).

10.17 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).

10.18 Acquisition Agreement dated as of March 27, 2001, between the Company and Genesis Exploration Ltd. (Filed as Exhibit 2 to the Company's report on Form 8-K filed May 15, 2001).

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.

99.1 Certificate pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99.2 Certificate pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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* *Management contract or compensatory plan or arrangement.*

(b) Reports on Form 8-K.

Form 8-K dated November 22, 2002, was filed on November 27, 2002, to report under Item 5 the re-issuance of the Company's 1999, 2000 and 2001 consolidated financial statements, as audited by Ernst & Young LLP, the Company's new independent auditors.

## 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 14, 2003

By: /s/ C. C. Stephenson, Jr.
C. C. Stephenson, Jr.
Chairman of the Board

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.<br>C. C. Stephenson, Jr. | Director and Chairman of the Board | March 14, 2003 |
| /s/ S. Craig George<br>S. Craig George | Director, President and Chief Executive Officer (Principal Executive Officer) | March 14, 2003 |
| /s/ William L. Abernathy<br>William L. Abernathy | Director, Executive Vice President and Chief Operating Officer | March 14, 2003 |
| /s/ William C. Barnes<br>William C. Barnes | Director, Executive Vice President, Chief Financial Officer, Secretary and Treasurer (Principal Financial Officer) | March 14, 2003 |
| Rex D. Adams | Director | March 14, 2003 |
| /s/ Bryan H. Lawrence<br>Bryan H. Lawrence | Director | March 14, 2003 |
| /s/ Joseph D. Mahaffey<br>Joseph D. Mahaffey | Director | March 14, 2003 |
| /s/ Gerald J. Maier<br>Gerald J. Maier | Director | March 14, 2003 |
| /s/ John T. McNabb, II<br>John T. McNabb, II | Director | March 14, 2003 |
| /s/ Michael F. Meimerstorf<br>Michael F. Meimerstorf | Vice President and Controller (Principal Accounting Officer) | March 14, 2003 |

## CERTIFICATIONS

I, S. Craig George, certify that:

1. I have reviewed this annual report on Form 10-K of Vintage Petroleum, Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:
   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Dated: March 14, 2003

\s\ S. Craig George
S. Craig George
Chief Executive Officer

I, William C. Barnes, certify that:

1. I have reviewed this annual report on Form 10-K of Vintage Petroleum, Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:
   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Dated: March 14, 2003

\s\ William C. Barnes
William C. Barnes
Chief Financial Officer

## INDEX TO FINANCIAL STATEMENTS

## VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

## 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, 2002 and 2001, 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, 2002. 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 financial position of Vintage Petroleum, Inc. and subsidiaries as of December 31, 2002 and 2001, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2002, the Company adopted the provisions of Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets*. In addition, as also discussed in Note 1, 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 12, 2003

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In thousands, except shares and per share amounts)

| | December 31, 2002 | December 31, 2001 |
|---|---|---|
| **ASSETS** | | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $ 9,259 | $ 6,359 |
| Accounts receivable - | | |
| Oil and gas sales | 90,267 | 73,246 |
| Joint operations | 9,542 | 12,041 |
| Derivative financial instruments receivable | - | 4,701 |
| Prepaids and other current assets | 21,021 | 34,382 |
| Assets of discontinued operations | 86,174 | 86,511 |
| Total current assets | 216,263 | 217,240 |
| PROPERTY, PLANT AND EQUIPMENT, at cost: | | |
| Oil and gas properties, successful efforts method | 2,487,549 | 2,434,592 |
| Oil and gas gathering systems and plants | 20,588 | 20,508 |
| Other | 26,501 | 25,367 |
| | 2,534,638 | 2,480,467 |
| Less accumulated depreciation, depletion and amortization | 1,047,665 | 803,135 |
| Total property, plant and equipment, net | 1,486,973 | 1,677,332 |
| GOODWILL, net | 21,099 | 156,990 |
| OTHER ASSETS, net | 51,469 | 56,340 |
| TOTAL ASSETS | $ 1,775,804 | $ 2,107,902 |

The accompanying notes are an integral part of these statements.

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Continued)
(In thousands, except shares and per share amounts)

| | December 31, 2002 | December 31, 2001 |
|---|---|---|
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| CURRENT LIABILITIES: | | |
| Revenue payable | $ 30,869 | $ 25,625 |
| Accounts payable - trade | 42,038 | 57,613 |
| Current income taxes payable | 18,722 | 21,638 |
| Short-term debt | 4,732 | 17,320 |
| Derivative financial instrument payable | 17,122 | - |
| Other payables and accrued liabilities | 54,281 | 42,471 |
| Liabilities of discontinued operations | 10,769 | 7,134 |
| Total current liabilities | 178,533 | 171,801 |
| LONG-TERM DEBT | 883,180 | 1,010,673 |
| DEFERRED INCOME TAXES | 137,015 | 177,777 |
| OTHER LONG-TERM LIABILITIES | 6,084 | 18,208 |
| COMMITMENTS AND CONTINGENCIES (Note 5) | | |
| STOCKHOLDERS' EQUITY, per accompanying statements: | | |
| Preferred stock, $.01 par, 5,000,000 shares authorized, zero shares issued and outstanding | - | - |
| Common stock, $.005 par, 160,000,000 shares authorized, 63,432,972 and 63,081,322 shares issued and 63,348,272 and 63,081,322 shares outstanding | 317 | 315 |
| Capital in excess of par value | 326,510 | 324,077 |
| Retained earnings | 274,971 | 428,443 |
| Accumulated other comprehensive loss | (28,573) | (21,632) |
| | 573,225 | 731,203 |
| Less treasury stock, at cost, 84,700 and zero shares | - | - |
| Less unamortized cost of restricted stock awards | 2,233 | 1,760 |
| Total stockholders' equity | 570,992 | 729,443 |
| TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY | $ 1,775,804 | $ 2,107,902 |

The accompanying notes are an integral part of these statements.

## VINTAGE PETROLEUM, INC. AND SUBSIDIARIES
## CONSOLIDATED STATEMENTS OF OPERATIONS
**(In thousands, except per share amounts)**

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | **2002** | **2001** | **2000** |
| REVENUES: | | | |
| Oil and gas sales | $ 577,699 | $ 707,090 | $ 649,736 |
| Gas marketing | 66,516 | 130,209 | 128,836 |
| Oil and gas gathering and processing | 5,731 | 17,032 | 19,998 |
| Gain (loss) on disposition of assets | 16,546 | 26,871 | (1,731) |
| Foreign currency exchange gain (loss) | 427 | 1,825 | (79) |
| Other income (expense) | (2,656) | 1,940 | (21,380) |
| Total revenues | 664,263 | 884,967 | 775,380 |
| COSTS AND EXPENSES: | | | |
| Lease operating, including production and export taxes | 204,293 | 204,650 | 153,522 |
| Exploration costs | 42,734 | 21,587 | 22,677 |
| Gas marketing | 64,906 | 126,373 | 123,787 |
| Oil and gas gathering and processing | 7,501 | 17,759 | 17,052 |
| General and administrative | 49,298 | 48,130 | 39,757 |
| Depreciation, depletion and amortization | 178,902 | 165,984 | 98,042 |
| Impairment of oil and gas properties | 98,720 | 29,050 | 225 |
| Amortization of goodwill | - | 11,940 | - |
| Impairment of goodwill | 76,351 | - | - |
| Interest | 77,714 | 64,720 | 48,437 |
| Loss on early extinguishment of debt | 8,154 | - | - |
| Total costs and expenses | 808,573 | 690,193 | 503,499 |
| Income (loss) from continuing operations before income taxes and cumulative effect of changes in accounting principles | (144,310) | 194,774 | 271,881 |
| PROVISION (BENEFIT) FOR INCOME TAXES: | | | |
| Current | 21,684 | 80,535 | 68,858 |
| Deferred | (60,772) | (12,210) | 31,537 |
| Total provision (benefit) for income taxes | (39,088) | 68,325 | 100,395 |
| Income (loss) from continuing operations before cumulative effect of changes in accounting principles | (105,222) | 126,449 | 171,486 |
| INCOME FROM DISCONTINUED OPERATIONS, net of income taxes | 22,105 | 7,058 | 25,421 |
| Income (loss) before cumulative effect of changes in accounting principles | (83,117) | 133,507 | 196,907 |
| CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES, net of income tax benefit of zero, zero and $542, respectively | (60,547) | - | (1,014) |
| NET INCOME (LOSS) | $(143,664) | $ 133,507 | $ 195,893 |

The accompanying notes are an integral part of these statements.

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Continued)

(In thousands, except per share amounts)

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| BASIC INCOME (LOSS) PER SHARE: | | | |
| Income (loss) from continuing operations before cumulative effect of changes in accounting principles | $ (1.66) | $ 2.01 | $ 2.74 |
| Income from discontinued operations | .35 | .11 | .41 |
| Income (loss) before cumulative effect of changes in accounting principles | (1.31) | 2.12 | 3.15 |
| Cumulative effect of changes in accounting principles | (.96) | - | (.02) |
| Net income (loss) | $ (2.27) | $ 2.12 | $ 3.13 |
| DILUTED INCOME (LOSS) PER SHARE: | | | |
| Income (loss) from continuing operations before cumulative effect of changes in accounting principles | $ (1.66) | $ 1.98 | $ 2.68 |
| Income from discontinued operations | .35 | .11 | .40 |
| Income (loss) before cumulative effect of changes in accounting principles | (1.31) | 2.09 | 3.08 |
| Cumulative effect of changes in accounting principles | (.96) | - | (.02) |
| Net income (loss) | $ (2.27) | $ 2.09 | $ 3.06 |
| Weighted average common share outstanding: | | | |
| Basic | 63,219 | 63,023 | 62,644 |
| Diluted | 63,219 | 64,027 | 63,963 |

The accompanying notes are an integral part of these statements.

## VINTAGE PETROLEUM, INC. AND SUBSIDIARIES
## CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
(In thousands, except per share amounts)

| | Common Stock | | Treasury | Capital In Excess of Par | Un-amortized Restricted Stock | Retained | Accumulated Other Compre-hensive Income | |
|---|---|---|---|---|---|---|---|---|
| | Shares | Amount | Shares | Value | Awards | Earnings | (Loss) | Total |
| BALANCE AT DECEMBER 31, 1999 | 62,408 | $ 312 | - | $ 314,490 | $ - | $ 116,327 | $ - | $ 431,129 |
| Comprehensive income: | | | | | | | | |
| Net income | - | - | - | - | - | 195,893 | - | 195,893 |
| Foreign currency translation adjustment | - | - | - | - | - | - | 1,201 | 1,201 |
| Total comprehensive income | | | | | | | | 197,094 |
| Exercise of stock options and resulting tax effects | 393 | 2 | - | 5,403 | - | - | - | 5,405 |
| Cash dividends declared ($.140 per share) | - | - | - | - | - | (8,771) | - | (8,771) |
| BALANCE AT DECEMBER 31, 2000 | 62,801 | 314 | - | 319,893 | - | 303,449 | 1,201 | 624,857 |
| Comprehensive income: | | | | | | | | |
| Transition adjustment for adoption of SFAS No. 133 | - | - | - | - | - | - | 14,915 | 14,915 |
| Net income | - | - | - | - | - | 133,507 | - | 133,507 |
| Foreign currency translation adjustment | - | - | - | - | - | - | (25,823) | (25,823) |
| Change in value of derivatives | - | - | - | - | - | - | (11,925) | (11,925) |
| Total comprehensive income | | | | | | | | 110,674 |
| Exercise of stock options and resulting tax effects | 170 | 1 | - | 1,970 | - | - | - | 1,971 |
| Issuance of restricted stock | 110 | - | - | 2,214 | (2,214) | - | - | - |
| Amortization of restricted stock awards | - | - | - | - | 454 | - | - | 454 |
| Cash dividends declared ($.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 income: | | | | | | | | |
| 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 | - | - | 85 | (1,473) | 945 | - | - | (528) |
| Cash dividends declared ($.155 per share) | - | - | - | - | - | (9,808) | - | (9,808) |
| BALANCE AT DECEMBER 31, 2002 | 63,433 | $ 317 | 85 | $ 326,510 | $ (2,233) | $ 274,971 | $ (28,573) | $ 570,992 |

The accompanying notes are an integral part of these statements.

**VINTAGE PETROLEUM, INC. AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(In thousands)**

| | For the Years Ended December 31, 2002 | 2001 | 2000 |
|---|---|---|---|
| CASH FLOWS FROM OPERATING ACTIVITIES: | | | |
| Net income (loss) | $(143,664) | $ 133,507 | $ 195,893 |
| Adjustments to reconcile net income (loss) to cash provided by operating activities, net of companies acquired - | | | |
| Income from discontinued operations, net of tax | (22,105) | (7,058) | (25,421) |
| Cumulative effect of change in accounting principle | 60,547 | - | 1,014 |
| Depreciation, depletion and amortization | 178,902 | 165,984 | 98,042 |
| Impairment of oil and gas properties | 98,720 | 29,050 | 225 |
| Amortization of goodwill | - | 11,940 | - |
| Impairment of goodwill | 76,351 | - | - |
| Exploration costs | 42,734 | 21,587 | 22,677 |
| Provision (benefit) for deferred income taxes | (60,772) | (12,210) | 31,537 |
| Foreign currency exchange (gain) loss | (427) | (1,825) | 79 |
| (Gain) loss on disposition of assets | (16,546) | (26,871) | 1,731 |
| Loss on early extinguishment of debt | 8,154 | - | - |
| Other non-cash items | 3,626 | 645 | - |
| | 225,520 | 314,749 | 325,777 |
| Decrease (increase) in receivables | (25,225) | 89,195 | (61,656) |
| Increase (decrease) in payables and accrued liabilities | 25,046 | (97,281) | 110,785 |
| Other working capital changes | 1,430 | (26,424) | 7,381 |
| Cash provided by continuing operations | 226,771 | 280,239 | 382,287 |
| Cash provided by discontinued operations | 14,098 | 15,446 | 13,400 |
| Cash provided by operating activities | 240,869 | 295,685 | 395,687 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | | |
| Capital expenditures - | | | |
| Oil and gas properties | (117,439) | (252,285) | (213,433) |
| Gathering systems and other | (5,672) | (5,767) | (2,581) |
| Proceeds from sales of oil and gas properties | 23,208 | 39,800 | 998 |
| Purchase of companies, net of cash acquired | - | (478,158) | (46,199) |
| Proceeds from sale of company, net of cash sold | 39,314 | - | - |
| Other | (453) | (8,195) | (2,929) |
| Cash used by investing activities - continuing operations | (61,042) | (704,605) | (264,144) |
| Cash used by investing activities - discontinued operations | (13,211) | (9,232) | (13,148) |
| Cash used by investing activities | (74,253) | (713,837) | (277,292) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | | |
| Issuance of common stock | 731 | 1,231 | 3,492 |
| Issuance of 8 1/4% Senior Notes Due 2012 | 350,000 | - | - |
| Partial redemption of 9% Senior Subordinated Notes Due 2005 | (103,000) | - | - |
| Issuance of 7 7/8% Senior Subordinated Notes Due 2011 | - | 199,930 | - |
| Advances on revolving credit facility and other borrowings | 289,427 | 319,050 | 70,388 |
| Payments on revolving credit facility and other borrowings | (679,615) | (88,431) | (224,343) |
| Dividends paid | (9,484) | (8,187) | (6,887) |
| Transaction costs on debt issuance | (9,972) | - | - |
| Cash provided (used) by financing activities | (161,913) | 423,593 | (157,350) |
| EFFECT OF EXCHANGE RATE CHANGE ON CASH | (1,803) | (429) | - |
| NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS | 2,900 | 5,012 | (38,955) |
| CASH AND CASH EQUIVALENTS, beginning of year | 6,359 | 1,347 | 40,302 |
| CASH AND CASH EQUIVALENTS, end of year | $ 9,259 | $ 6,359 | $ 1,347 |

The accompanying notes are an integral part of these statements.

## 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 and Italy. 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. and 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 2000 and 2001 amounts have been reclassified to conform with the 2002 presentation, including reclassifications required for presentation of the discontinued operations in Note 9. These reclassifications had no effect on the Company's net income 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 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. 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 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. 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 on a property-by-property basis, considering factors such as future drilling and exploitation plans and lease terms. Costs related to impaired prospects are charged to expense. An impairment expense could result if oil and gas prices decline in the future or if downward reserves revisions are recorded, as it may not be economic to develop some of these unproved properties.

As of December 31, 2002, the Company had total unproved oil and gas property costs of approximately $88.0 million consisting of undeveloped leasehold costs of $76.0 million, including $56.3 million in Canada, and unevaluated exploratory drilling costs of $12.0 million. Approximately $15.9 million of the total unevaluated costs are associated with the Company's drilling program in Yemen.

Costs of development dry holes and proved leaseholds are amortized on the unit-of-production method based on proved reserves on a field basis. The depreciation of capitalized production equipment and drilling costs 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*. 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 $55.4 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 majority of the asset retirement obligations of the Company relate to the plugging and abandonment of oil and gas wells. However, future abandonment liabilities will also be 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. The liability accretes over time with a charge to accretion expense. At January 1, 2003 there are no assets legally restricted for purposes of settling asset retirement obligations. The Company adopted the new standard effective January 1, 2003, and recorded an increase in property, plant and equipment of approximately $50.4 million, a decrease in accumulated depreciation, depletion and amortization of approximately $44.6 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 $4.4 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 $7.5 million.

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 $98.7 million, $29.1 million and $0.2 million in 2002, 2001 and 2000, respectively.

In estimating the future net revenues at December 31, 2002, to be used for impairment testing, the Company assumed that current oil prices would return to more historical levels over a short period of time and that current gas prices would remain at the levels experienced in recent years. The Company assumed that operating costs would escalate annually beginning at current levels. Due to the volatility of oil and gas prices, it is possible that the Company's assumptions regarding oil and gas prices may change in the future and may result in future impairment provisions.

On January 1, 2002, the Company adopted the provision of Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* ("SFAS No. 144"). SFAS No. 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 No. 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") (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.

On July 20, 2001, the FASB issued Statement of Financial Accounting Standards No. 141, *Business Combinations* ("SFAS No. 141"), and Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* ("SFAS No. 142"). SFAS No. 141 requires all business combinations initiated after June 30, 2001, to be accounted for using the purchase method of accounting. Under SFAS No. 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.

The Company's May 2001 acquisition of Genesis was accounted for using the purchase method of accounting. The Company adopted SFAS No. 141 and SFAS No. 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 will assess its Canadian operation's goodwill as of December 31 each year and will perform interim tests for goodwill impairment should an event occur or circumstances change that would, more likely than not, reduce the fair value of the Canadian reporting unit below its carrying value. On December 31, 2002, the Company recorded an additional impairment charge of $76.4 million as an operating expense resulting from its annual assessment.

*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.

The Company adopted Securities and Exchange Commission Staff Accounting Bulletin No. 101, *Revenue Recognition* ("SAB No. 101"), in the fourth quarter of 2000, effective January 1, 2000. SAB No. 101 requires oil inventories held in storage facilities to be valued at cost. Cost is defined as lifting costs plus depreciation, depletion and amortization. The Company previously followed industry practice by valuing oil inventories at market. As a result of adopting SAB No. 101, the Company recorded in its statement of operations a cumulative effect of change in accounting principle, reducing net income by $1.0 million, net of income tax effects of $0.5 million.

*Hedging*

The Company periodically uses hedges to reduce the impact of oil and gas price fluctuations. In June 1998, the FASB issued Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (as amended, "SFAS No. 133"). SFAS No. 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 No. 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 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 derivative exceeds the cumulative change in the present value of expected cash flows, the excess, if any, 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. Prior to the adoption of SFAS No. 133, derivative financial instruments that qualified as hedges were not recorded on the balance sheet. Gains or losses on these hedges were recognized as an adjustment to sales revenue when the related transactions being hedged affected earnings.

Upon adoption of SFAS No. 133 on January 1, 2001, the Company 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 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 taken to 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. At December 31, 2001, the Company had a derivative financial instrument receivable of $4.7 million related to cash flow hedges in place on anticipated 2002 production and at December 31, 2002, the Company had a derivative financial instrument payable of $17.1 million related to cash flow hedges in place on anticipated 2003 production. During 2002 and 2001, the Company recorded losses related to hedge ineffectiveness, net of tax, of $0.8 million and $0.1 million, respectively. The Company did not discontinue any hedges because of the probability that the original forecasted transaction would not occur.

The Company participated in oil hedges covering 4.9 million barrels and gas hedges covering 13.5 million MMBtu (millions of British thermal units) in 2002. The impact of the oil hedges decreased its U.S. average oil price by 88 cents to $21.78 per barrel, its Argentina average oil price by eight cents to $20.98 per barrel, its average oil price from continuing operations by 35 cents to $21.31 per barrel and its overall average oil price by 33 cents to $21.27 per barrel. The impact of the gas hedges decreased its U.S. average gas price by nine cents to $2.85 per Mcf (thousand cubic feet), decreased its Canada average gas price by one cent to $2.48 per Mcf and decreased its overall average gas price by four cents to $2.26 per Mcf. The Company participated in oil hedges covering 5.5 million barrels during 2001, the impact of which increased its U.S. average oil price by 91 cents to $23.08 per barrel, its Argentina average oil price by $1.14 to $21.80 per barrel, its average oil price from continuing operations by 95 cents to $22.22 per barrel and its overall average oil price by 89 cents to $21.93 per barrel. The Company participated in oil hedges covering 9.3 million barrels during 2000, the impact of which reduced its U.S. average oil price by $4.10 to $22.85 per barrel, its average oil price from continuing operations by $1.99 to $25.63 per barrel and its overall average oil price by $1.86 to $25.55 per barrel.

*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.

*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, 2002, 2001 and 2000, the Company made cash payments for interest totaling $74.2 million, $58.6 million and $48.3 million, respectively. Cash payments for U.S. income taxes of $0.6 million, $24.1 million and $19.8 million were made during 2002, 2001 and 2000, respectively. The Company made cash payments of $12.0 million, $77.8 million and $9.5 million during 2002, 2001 and 2000 for foreign income taxes, primarily in Argentina.

In December 2000, the Company purchased 100 percent of the outstanding common stock of Cometra Energy (Canada) Ltd. The total purchase price included both cash and the assumption of $7.6 million in net liabilities. These net liabilities are not reflected in the Company's 2000 statement of cash flows.

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.

*Earnings 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 2002, the assumed exercise of any options would have been anti-dilutive. Therefore, the amounts reported for basic and diluted earning (loss) per share were the same. 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 years ended December 31, 2001 and 2000, the Company had outstanding stock options for 3,244,400 and 714,000 additional shares of the Company's common stock, respectively, with average exercise prices of $19.22 and $20.19, respectively, which were anti-dilutive. These shares will dilute basic earnings per share in the future, if exercised, and may impact diluted earnings per share in the future depending on the market price of the Company's common stock. Subsequent to December 31, 2002, the Company accepted for exchange certain outstanding stock options and granted restricted stock and restricted stock rights (see Note 14).

*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 $5.3 million, $6.2 million and $3.8 million in 2002, 2001 and 2000, respectively.

*Lease Operating Expense*

On February 13, 2002, the Argentine government announced a 20 percent tax on oil exports, effective March 1, 2002, which is reflected in lease operating expenses. 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.

Included in lease operating expenses are the following items (in thousands):

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| Argentina oil export taxes | $ 24,824 | $ - | $ - |
| Transportation and storage expenses | 8,839 | 10,311 | 7,300 |
| Gross production taxes | 9,887 | 15,345 | 16,974 |

*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.

*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.

*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.

The Company's operations in Argentina represented approximately 38 percent of its 2002 total production and approximately 40 percent of the Company's total proved reserves at December 31, 2002.

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, in early December 2001, the Argentine government instituted restrictions that prohibited 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. 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 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, 2002, was 3.38 pesos to one U.S. dollar.

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 reflects 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 lease operating 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. Despite these changes, the Company believes that the facts and circumstances indicate that the U.S. dollar remains the functional currency of its Argentine operations.

*Stock-based 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. The Company accounts for these plans under Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* ("APB No. 25") and has adopted the disclosure-only provisions of Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation* ("SFAS No. 123"). Accordingly, no compensation cost for stock options granted 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 day of grant. Had compensation cost for these plans been determined consistent with the provisions of SFAS No. 123, the Company's stock-based compensation expense, net income (loss) and income (loss) per share would have been adjusted to the following pro forma amounts (in thousands, except per share amounts):

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Stock-based compensation expense - as reported | $ 1,329 | $ 454 | $ - |
| Stock-based compensation expense - pro forma | 5,775 | 6,255 | 3,590 |
| Net income (loss) - as reported | (143,664) | 133,507 | 195,893 |
| Net income (loss) - pro forma | (146,889) | 129,237 | 193,252 |
| Income (loss) per share - as reported: | | | |
| Basic | (2.27) | 2.12 | 3.13 |
| Diluted | (2.27) | 2.09 | 3.06 |
| Income (loss) per share - pro forma: | | | |
| Basic | (2.32) | 2.05 | 3.08 |
| Diluted | (2.32) | 2.02 | 3.02 |

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 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. The weighted average assumptions used for options granted in 2000 include a dividend yield of 0.6 percent, expected volatility of approximately 46.7 percent, a risk-free interest rate of approximately 6.3 percent and expected lives of 4.4 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*

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| Net income (loss) | $ (143,664) | $ 133,507 | $ 195,893 |
| Transition adjustment for adoption of SFAS No. 133 | - | 14,915 | - |
| Foreign currency translation adjustments | 4,965 | (25,823) | 1,201 |
| Changes in value of derivatives, net of tax | (11,906) | (11,925) | - |
| Comprehensive income (loss) | $ (150,605) | $ 110,674 | $ 197,094 |

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, | |
|---|---|---|
| | 2002 | 2001 |
| Reclassification of cumulative effect of adoption of SFAS No. 133 for (gains) losses included in net income (loss) | $ - | $ (18,540) |
| Unrealized gain (loss) during the period | (15,692) | 4,894 |
| Reclassification adjustment for (gains) losses included in net income (loss) | (4,894) | - |
| | (20,586) | (13,646) |
| Income tax benefit | (8,680) | (1,721) |
| Changes in value of derivatives, net of tax | $ (11,906) | $ (11,925) |

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

| | December 31, | |
|---|---|---|
| | 2002 | 2001 |
| Foreign currency translation adjustments | $ (19,657) | $ (24,622) |
| Changes in value of derivatives, net of tax | (8,916) | 2,990 |
| | $ (28,573) | $ (21,632) |

## 2. Long-term Debt

Long-term debt at December 31, 2002 and 2001, consisted of the following (in thousands):

| | 2002 | 2001 |
|---|---|---|
| Revolving credit facility | $ 33,800 | $ 411,400 |
| 8 1/4% Senior Notes Due 2012 | 350,000 | - |
| Senior subordinated notes: | | |
| 9% Notes due 2005, less unamortized discount | 49,958 | 149,837 |
| 8 5/8% Notes due 2009, less unamortized discount | 99,484 | 99,503 |
| 9 3/4% Notes due 2009 | 150,000 | 150,000 |
| 7 7/8% Notes due 2011, less unamortized discount | 199,938 | 199,933 |
| | $ 883,180 | $ 1,010,673 |

A total of $83.8 million of debt shown above matures in 2005, all of which was repaid in early 2003. In February 2003, the Company advanced funds under its revolving credit facility to redeem the remainder of the 9% Notes due 2005. Subsequently, a portion of the proceeds from the January 2003 sale of the Company's operations in Ecuador was used to repay the entire outstanding balance under the revolving credit facility. All other debt matures in 2009 or later. The Company had $11.7 million and $9.5 million of accrued interest payable related to its long-term debt at December 31, 2002 and 2001, respectively, 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, 2002) 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 2003. At December 31, 2002, the unused availability under the Bank Facility (considering outstanding letters of credit of approximately $15.9 million) was approximately $250 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. Total outstanding advances at December 31, 2002, were $33.8 million at an average interest rate of 3.28 percent.

The Company's borrowing base is redetermined on a semi-annual basis by the banks based upon 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.

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 tangible net worth (as defined therein) of not less than $425 million plus 75 percent of the net proceeds of any future equity offerings less any impairment write downs required by GAAP or by the Securities and Exchange Commission and excluding any impact related to SFAS No. 133.

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 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.

*Senior Subordinated Notes*

On December 20, 1995, the Company issued $150 million of its 9% Notes. The 9% Notes are 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, as previously discussed, redeemed the remaining $50 million of the 9% Notes in 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 $1.0 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 $1.7 million ($1.0 million net of tax), which will be recorded 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 are redeemable at the option of the Company, in whole or in part, at any time on or after February 1, 2002. The 8 5/8% Notes mature on February 1, 2009, with interest payable semi-annually on February 1 and August 1 of each year.

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 are redeemable at the option of the Company, in whole or in part, at any time on or after February 1, 2004. The 9 3/4% Notes mature on June 30, 2009, with interest payable semi-annually on June 30 and December 30 of each year.

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% Notes, 8 5/8% Notes, 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 which reserve shares of common stock for issuance to key employees and directors. 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, 2002, awards for a total of 502,777 shares of common stock remain available for grant under the 1990 Plan.

The 1990 Plan is administered by 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 are available for issuance to the outside directors of the Company. Each outside director receives an initial option to purchase 5,000 shares of common stock during the director's first year of service to the Company. Annually thereafter, options to purchase 1,000 shares of common stock are to be granted to each outside director. Options granted pursuant to the Director Plan are non-qualified stock options with terms not to exceed 10 years and the option exercise price must equal the fair market value of the common stock on the date of grant. As of December 31, 2002, options for a total of 9,000 shares of common stock remain available for grant under the Director Plan. Under the terms of the Director Plan, no options will be granted under this plan subsequent to May 11, 2003.

The following is an analysis of all option activity under the 1990 Plan and the Director Plan for 2002, 2001 and 2000:

| | 2002 | | 2001 | | 2000 | |
|---|---|---|---|---|---|---|
| | Shares | Wtd. Avg. Exercise Price | Shares | Wtd. Avg. Exercise Price | Shares | Wtd. Avg. Exercise Price |
| Beginning stock options outstanding | 5,715,186 | $14.57 | 5,026,592 | $13.16 | 4,616,142 | $11.61 |
| Stock options granted | 77,000 | 11.47 | 1,038,000 | 20.87 | 853,000 | 19.62 |
| Stock options canceled | (270,450) | 18.94 | (179,500) | 18.53 | (49,000) | 13.70 |
| Stock options exercised | (81,000) | 7.31 | (169,906) | 7.24 | (393,550) | 8.87 |
| Ending stock options outstanding | 5,440,736 | $14.42 | 5,715,186 | $14.57 | 5,026,592 | $13.16 |
| Ending stock options exercisable | 3,894,071 | $12.18 | 2,869,131 | $13.47 | 2,238,142 | $10.89 |
| Weighted average SFAS No. 123 fair value of options granted | $ 4.80 | | $ 9.09 | | $ 9.02 | |

Of the 5,440,736 options outstanding at December 31, 2002: (a) 2,346,336 options have exercise prices between $7.25 and $10.35, with a weighted average exercise price of $8.48 and a weighted average contractual life of 3.8 years (all of these options are currently exercisable); (b) 133,000 options have exercise prices between $10.81 and $15.35, with a weighted average exercise price of $12.25 and a weighted average contractual life of 5.0 years (46,001 of these options are currently exercisable at a weighted average price of $11.92); (c) 704,900 options have exercise prices between $15.50 and $19.08, with a weighted average exercise price of $15.54 and a weighted average contractual life of 4.2 years (all of these options are currently exercisable); and (d) 2,256,500 options have exercise prices between $19.28 and $22.94, with a weighted average exercise price of $20.37 and a weighted average contractual life of 6.6 years (796,834 of these options are currently exercisable at a weighted average price of $20.13).

All of the outstanding options are exercisable at various times in years 2003 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 during 2002 and 2001. All of the restricted stock awards vest over a three-year period. The related restricted stock compensation expense, net of forfeitures, of $4.8 million (based on the stock price on the date of grant) is being amortized over the vesting periods. During 2002 and 2001, the Company recorded restricted stock compensation expense of $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 2002 and 2001:

| | Shares | |
|---|---|---|
| | 2002 | 2001 |
| Beginning restricted stock awards outstanding | 110,000 | - |
| Restricted stock awards granted | 416,650 | 110,000 |
| Restricted stock awards canceled | (119,200) | - |
| Restricted stock awards vested | (16,666) | - |
| Ending restricted stock awards outstanding | 390,784 | 110,000 |

At December 31, 2002, a total of 6,045,543 shares of the Company's common stock are reserved for issuance pursuant to the 1990 Plan and the Director Plan.

Subsequent to December 31, 2002, the Company accepted for exchange certain outstanding stock options and granted restricted stock awards (see Note 14).

*Preferred Stock*

Preferred stock at December 31, 2002, 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 Company's Board of Directors (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 one cent per Right at the option of the Board.

## 4. Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the purchase of Genesis in 2001. All of the Company's goodwill is related to the Company's Canadian operations, which is consistent with the Canadian segment identified in Note 10. Effective January 1, 2002, the Company adopted the provisions of SFAS No. 142. SFAS No. 142 changes 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 No. 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. In future years, this assessment must be conducted at least annually and any such impairment must 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 No. 142. The Company performed another assessment of goodwill for impairment as of December 31, 2002, and recorded an additional non-cash charge of $76.4 million as an operating expense. Certain downward revisions recorded to the Company's Canadian oil and gas reserves in the fourth quarter of 2002 were the primary factor which led to the additional impairment.

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.

The Company has no intangible assets other than the goodwill of its Canadian operations, which had a net book value (after the impairments) of $21.1 million as of December 31, 2002. The changes in the carrying amount of goodwill for the year ended December 31, 2002, are 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 |

The results of operations presented below for the years ended December 31, 2001 and 2000, reflect the operations of the Company had the Company adopted the non-amortization provisions of SFAS No. 142 effective January 1, 2000 (in thousands, except per share amounts):

| | 2001 | 2000 |
|---|---|---|
| Reported net income | $ 133,507 | $ 195,893 |
| Goodwill amortization | 11,940 | - |
| Adjusted net income | $ 145,447 | $ 195,893 |
| Adjusted basic income per share | $ 2.31 | $ 3.13 |
| Adjusted diluted income per share | $ 2.27 | $ 3.06 |

## 5. Commitments and Contingencies

The Company is committed to perform a certain number of work units in the Chaco concession in Bolivia that it expects to complete by drilling one well in 2003 at an estimated cost of $6.3 million.

The Company had $15.9 million in letters of credit outstanding at December 31, 2002. These letters of credit relate primarily to various obligations for acquisition and exploration activities in Canada, South America and Yemen and 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 $3.5 million, $2.9 million and $2.3 million for 2002, 2001 and 2000, respectively. The future minimum commitments under long-term, non-cancellable leases for office space are $3.4 million, $3.4 million, $4.9 million, $2.5 million and $1.0 million for the years 2003 through 2007, respectively, with $0.3 million remaining in years thereafter.

The Company has entered into certain firm gas transportation and compression agreements in Bolivia whereby the Company has committed to transport and compress certain volumes of gas at established government-regulated fees. While these fees are not fixed, they are government-regulated and therefore, the Company believes the risk of significant fluctuations is minimal. The Company entered into these arrangements to ensure its access to gas markets and currently expects to produce sufficient volumes to utilize all of the contracted transportation and compression capacity under these arrangements. Based on the current fee level, these commitments total approximately $2.7 million in 2003, $1.4 million in 2004, $0.3 million in 2005, $0.3 million in 2006, $0.3 million in 2007 and $0.6 million thereafter.

On November 5, 1996, the Province of Santa Cruz, Argentina brought suit against the Company's subsidiary Cadipsa S.A. in the Corte Suprema de Justicia de la Nacion (the Supreme Court of Justice of the Argentine Republic, Buenos Aires, Argentina), Dossier No. s-1451, seeking to recover approximately $10.6 million (which sum includes interest) allegedly due as additional royalties on four concessions granted in 1990 in which the Company currently owns 100 percent working interest. The Company and its predecessors in title have been paying royalties at an eight percent rate; the Province of Santa Cruz claimed the rate should be 12 percent. On May 19, 2000, the Company announced it had received notice of an adverse decision regarding this suit. As a result of the court's decision, the Company recorded a one-time charge to "Other expense" in the second quarter of 2000 for approximately $25.1 million ($16.3 million after-tax). While the Company believes that it is entitled to partial indemnification by a third party with respect to the decision, no amount has been accrued for this gain contingency. The pre-tax amount remaining to be paid of 1 million pesos ($300,000) is included in "Other payables and accrued liabilities" in the accompanying balance sheet. The impact of the court's decision on the Company's Argentine production, reserves and present value was not material.

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 hedges to reduce the impact of oil and natural 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.

At December 31, 2002, the Company was a party to oil price swap agreements for various periods of 2003 covering 3.0 million barrels at a weighted average NYMEX reference price of $24.90 per barrel and gas price swap agreements for various periods of 2003 covering 20.1 MMBtu at a weighted average NYMEX reference price of $4.02 per MMBtu. The Canadian portion of the gas swap agreements (approximately 9.1 million MMBtu) is at a weighted average NYMEX reference price of 6.63 Canadian dollars per MMBtu. The U.S. portion of the gas swap agreements (approximately 11 million MMBtu) is at a weighted average NYMEX reference price of $4.00 per MMBtu. Additionally, the Company has entered into basis swap agreements for the approximately 8.4 million MMBtu of its U.S. gas production covered by the gas swap agreements. These basis swaps establish a differential between the NYMEX reference price and the various delivery points at levels that are comparable to the historical differentials received by the Company. Subsequent to December 31, 2002, the Company entered into additional oil hedging contracts for various periods in 2003 covering an additional 1.1 million barrels of oil at a weighted average NYMEX reference price of $29.86 per barrel. In total, the Company has entered into oil hedging contracts covering 2003 oil production of 4.1 million barrels at a weighted average NYMEX reference price of $26.26 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, 2002 and 2001, was $899.5 million and $1.02 billion, respectively, compared with carrying values of $883.2 million and $1.01 billion, 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, 2002 and 2001, the Company would have paid approximately $17.1 million and received approximately $4.7 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.

## 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):

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Domestic | $ (29,442) | $ 117,240 | $ 123,951 |
| Foreign | (114,868) | 77,534 | 147,930 |
| | $ (144,310) | $ 194,774 | $ 271,881 |

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):

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Current: | | | |
| Domestic | $ (10,273) | $ 46,486 | $ 17,053 |
| Foreign | 31,957 | 34,049 | 51,805 |
| Deferred: | | | |
| Domestic | 93 | (2,087) | 32,460 |
| Foreign | (60,865) | (10,123) | (923) |
| | $ (39,088) | $ 68,325 | $ 100,395 |

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

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| U.S. federal statutory income tax rate | 35.0% | 35.0% | 35.0% |
| State income tax | 0.8 | 2.4 | 1.8 |
| Foreign operations | (8.8) | (1.7) | 2.0 |
| U.S. federal income tax credits | - | (0.8) | - |
| Other | 0.1 | 0.2 | (0.1) |
| | 27.1% | 35.1% | 36.9% |

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, 2002 and 2001, are as follows (in thousands):

| | 2002 | 2001 |
|---|---|---|
| Deferred Tax Assets: | | |
| U.S. federal and state net operating loss carryforwards | $ 1,648 | $ 1,073 |
| Foreign net operating loss carryforwards | 23,551 | 33,421 |
| Foreign tax credit carryforwards | 2,940 | 3,559 |
| Other temporary book/tax differences | 652 | 2,961 |
| | 28,791 | 41,014 |
| Deferred Tax Liabilities: | | |
| Book/tax differences in property basis | 150,731 | 211,098 |
| Other temporary book/tax differences | 15,075 | 7,693 |
| | 165,806 | 218,791 |
| Net deferred tax liability | $ 137,015 | $ 177,777 |

The Company generated a U.S. federal regular income tax net operating loss ("NOL") in 2002, which it intends to carry back against prior year taxable income in order to receive a refund of taxes previously paid. The Company also has 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 amount of unrecognized deferred tax liability related to these unremitted earnings is not practicable to determine at this time.

The Company has a Bolivian income tax NOL carryforward of approximately $55 million that does not expire. The Company also has an Argentine income tax NOL at December 31, 2002, of approximately 59 million pesos ($17 million) in its subsidiary, Vintage Petroleum Argentina S.A., that expires in varying annual amounts over a four-year period beginning in 2003 and can be used to offset future income tax liabilities. The Company expects to fully utilize the entire remaining Argentine NOL carryforward in 2003. Additionally, the Company also has a Canadian income tax NOL carryforward of approximately C$17 million ($11 million), approximately 75 percent of which will expire in 2008 with the balance expiring in 2009. The Company expects to fully utilize this entire NOL carryforward prior to its expiration.

## 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.

The Genesis Acquisition purchase price was allocated as of May 2, 2001, as follows (in thousands):

| | C$ | US$ (a) |
|---|---|---|
| Total purchase price | $ 944,423 | $ 616,866 |
| Long-term debt assumed | (135,000) | (88,178) |
| Negative working capital assumed | (100,854) | (65,874) |
| Amount paid | 708,569 | 462,814 |
| Net assets at May 2, 2001 | (221,000) | (144,350) |
| Excess of purchase price over net assets at May 2, 2001 | $ 487,569 | $ 318,464 |
| Allocation of excess of purchase price over net assets: | | |
| Fair market value adjustment to oil and gas properties | $ 394,584 | $ 257,729 |
| Goodwill | 268,763 | 175,547 |
| Increase in deferred income taxes | (170,347) | (111,265) |
| Increase in accrued liabilities | (5,431) | (3,547) |
| | $ 487,569 | $ 318,464 |

(a) Converted at the May 2, 2001, exchange rate of US$1/C$1.5310.

If the Genesis Acquisition had been consummated as of January 1, 2000, the Company's unaudited pro forma revenues and net income for the years ended December 31, 2001 and 2000, 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.

| | 2001 | 2000 |
|---|---|---|
| | (In thousands, except per share amounts) | |
| Revenues | $ 943,756 | $ 905,133 |
| Income from continuing operations before cumulative effect of change in accounting principle | 124,059 | 148,491 |
| Net income | 131,117 | 172,943 |
| Basic Income Per Share: | | |
| Income from continuing operations before cumulative effect of change in accounting principle | $ 1.97 | $ 2.37 |
| Net income | 2.08 | 2.76 |
| Diluted Income Per Share: | | |
| Income from continuing operations before cumulative effect of change in accounting principle | $ 1.94 | $ 2.32 |
| Net income | 2.05 | 2.70 |

## 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 December 16, 2002, the Company announced that it had signed an agreement to sell its operations in Ecuador. The transaction was approved by the Company's Board of Directors in December 2002 and the sale closed on January 31, 2003. The Company received $137.4 million in cash, subject to post-closing adjustments. In accordance with the rules established by SFAS No. 144, the Company's operations in Trinidad, along with the gain on the sale, and the Company's operations in Ecuador are accounted for as discontinued operations in the accompanying consolidated financial statements.

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| Loss from discontinued operations | $ (711) | $ (980) | $ (104) |
| Deferred tax benefit | (253) | (343) | - |
| Net operating loss from discontinued operations | (458) | (637) | (104) |
| 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) | $ (104) |

| | December 31, | |
|---|---|---|
| | 2002 | 2001 |
| Current assets | $ - | $ 1,274 |
| Property, plant and equipment, net | - | 7,898 |
| Assets of discontinued operations | $ - | $ 9,172 |
| Current liabilities of discontinued operations | $ - | $ 972 |

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| Income from discontinued operations | $ 10,113 | $ 10,186 | $ 18,090 |
| Deferred tax expense (benefit) | 2,493 | 2,491 | (7,435) |
| Income loss from discontinued operations, net of tax | $ 7,620 | $ 7,695 | $ 25,525 |

| | December 31, | |
|---|---|---|
| | 2002 | 2001 |
| Current assets | $ 19,365 | $ 12,650 |
| Property, plant and equipment, net | 58,968 | 49,814 |
| Other assets, net | 2,676 | 3,761 |
| Deferred income tax asset | 5,165 | 11,114 |
| Assets of discontinued operations | $ 86,174 | $ 77,339 |
| Current liabilities of discontinued operations | $ 10,769 | $ 6,162 |

In accordance with SFAS No. 144, the assets of the Company's operations in Trinidad and 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 and 2001.

## 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 natural gas and crude oil. Revenues for the gathering/plant segment arise from the processing, transportation and sale of natural 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 and Italy. 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.

| | Exploration and Production | | | | |
|---|---|---|---|---|---|
| **2002** (in thousands) | **U.S.** | **Canada** | **Argentina** | **Bolivia** | **Other Foreign** |
| Revenues from external customers | $ 235,355 | $ 113,758 | $ 232,787 | $ 12,344 | $ - |
| Intersegment revenues | - | - | - | - | - |
| Depreciation, depletion and amortization expense | 51,026 | 73,550 | 46,067 | 3,564 | - |
| Impairment of oil and gas properties | 16,972 | 81,748 | - | - | - |
| Impairment of goodwill | - | 136,898 | - | - | - |
| Segment operating income (loss) | 68,635 | (243,343) | 119,911 | 4,452 | (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** |
|---|---|---|---|---|
| Revenues from external customers | $ 5,731 | $ 66,517 | $ (2,229) | $ 664,263 |
| Intersegment revenues | - | 902 | - | 902 |
| Depreciation, depletion and amortization expense | 1,687 | - | 3,008 | 178,902 |
| Impairment of oil and gas properties | - | - | - | 98,720 |
| Impairment of goodwill | - | - | - | 136,898 |
| Segment operating income (loss) | (3,457) | 1,610 | (5,237) | (69,691) |
| 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 |

| | Exploration and Production | | | | |
|---|---|---|---|---|---|
| **2001** (in thousands) | U.S. | Canada | Argentina | Bolivia | Other Foreign |
| Revenues from external customers | $ 386,344 | $ 86,274 | $ 243,329 | $ 17,648 | $ - |
| Intersegment revenues | - | - | - | - | - |
| Depreciation, depletion and amortization expense | 60,426 | 52,072 | 44,252 | 5,032 | - |
| Impairment of oil and gas properties | 9,555 | 18,895 | 600 | - | - |
| Segment operating income (loss) | 196,894 | (34,845) | 137,459 | 8,230 | (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 |
|---|---|---|---|---|
| Revenues from external customers | $ 17,032 | $ 130,209 | $ 4,131 | $ 884,967 |
| Intersegment revenues | - | 1,968 | - | 1,968 |
| Depreciation, depletion and amortization expense | 1,326 | - | 2,876 | 165,984 |
| Impairment of oil and gas properties | - | - | - | 29,050 |
| Segment operating income (loss) | (2,053) | 3,836 | 1,256 | 307,624 |
| 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 |

| | Exploration and Production | | | | |
|---|---|---|---|---|---|
| **2000** (in thousands) | U.S. | Canada | Argentina | Bolivia | Other Foreign |
| Revenues from external customers | $ 346,574 | $ 2,281 | $ 256,234 | $ 19,535 | $ - |
| Intersegment revenues | - | - | - | - | - |
| Depreciation, depletion and amortization expense | 53,184 | 586 | 33,077 | 7,421 | - |
| Impairment of oil and gas properties | 225 | - | - | - | - |
| Segment operating income (loss) | 192,508 | 1,040 | 170,301 | (3,796) | (6,121) |
| Total assets | 524,588 | 57,564 | 459,219 | 126,399 | 21,030 |
| Capital investments | 64,124 | 52,788 | 92,885 | 28,740 | 20,132 |
| Long-lived assets | 477,198 | 53,306 | 401,702 | 97,526 | 20,541 |

| **2000** (in thousands) | Gathering/ Plant | Gas Marketing | Corporate | Total |
|---|---|---|---|---|
| Revenues from external customers | $ 19,998 | $ 128,836 | $ 1,922 | $ 775,380 |
| Intersegment revenues | 2,080 | 2,372 | - | 4,452 |
| Depreciation, depletion and amortization expense | 1,567 | - | 2,207 | 98,042 |
| Impairment of oil and gas properties | - | - | - | 225 |
| Segment operating income (loss) | 1,380 | 5,049 | (286) | 360,075 |
| Total assets | 13,479 | 35,977 | 113,746 | 1,352,002 |
| Capital investments | 299 | - | 2,334 | 261,302 |
| Long-lived assets | 5,862 | - | 4,940 | 1,061,075 |

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. Corporate general and administrative costs and interest costs, including the loss on early extinguishment of debt, are not allocated to segments.

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, the impact of hedges and $26.9 million of gains on the sale of oil and gas properties). During 2000, sales to two crude oil purchasers of the exploration and production segment represented approximately 21 percent and 15 percent, respectively, of the Company's total revenues (exclusive of eliminations of intersegment sales and the impact of hedges).

## 11. Detail of Prepaids and Other Current Assets

| (In thousands) | 2002 | 2001 |
|---|---|---|
| Property divestiture proceeds receivable | $ - | $ 7,287 |
| Other prepaids and current assets | 21,021 | 27,095 |
| | $ 21,021 | $ 34,382 |

## 12. Quarterly Results (Unaudited)

The following is a summary of the quarterly results of operations for the years ended December 31, 2002 and 2001. All of the quarters for 2002 and 2001 have been restated to exclude the Company's discontinued operations in Trinidad and Ecuador, except net income (loss) and income (loss) per share (see Note 9).

| (In thousands, except per share amounts) | Quarter Ended | | | |
|---|---|---|---|---|
| | Mar. 31 | Jun. 30 | Sept. 30 | Dec. 31 |
| 2002 (a) | | | | |
| Revenues | $ 135,806 | $ 190,955 | $ 166,880 | $ 170,622 |
| Operating income (loss) | 4,662 | 52,982 | 39,008 | (155,094)(c,d) |
| Provision (benefit) for income taxes | (6,479) | 3,264 | 4,223 | (40,096) |
| Income (loss) before cumulative effect of change in accounting principle | (5,620)(b) | 22,429 | 31,695 | (131,621) |
| Net income (loss) | (66,167)(b) | 22,429 | 31,695 | (131,621)(c,d) |
| Income (loss) before cumulative effect of change in accounting principle per share | | | | |
| Basic | (.09)(b) | .36 | .50 | (2.08)(c,d) |
| Diluted | (.09)(b) | .35 | .50 | (2.08)(c,d) |
| Income (loss) per share: | | | | |
| Basic | (1.05)(b) | .36 | .50 | (2.08)(c,d) |
| Diluted | (1.05)(b) | .35 | .50 | (2.08)(c,d) |
| 2001(a) | | | | |
| Revenues | $ 269,296 | $ 247,187 | $ 185,002 | $ 183,482 |
| Operating income | 117,222 | 97,825 | 23,783(d) | 20,664(d) |
| Provision (benefit) for income taxes | 37,846 | 31,295 | 737 | (1,553) |
| Net income | 70,698 | 52,219 | 6,242(d) | 4,348(d) |
| Income per share: | | | | |
| Basic | 1.12 | .83 | .10(d) | .07(d) |
| Diluted | 1.10 | .81 | .10(d) | .07(d) |

(a) The quarters subsequent to March 31, 2001 include the results of Genesis (see Note 8).

(b) 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 96 cents per share.

(c) The quarter ended December 31, 2002, includes goodwill impairment of $76.4 million, or $1.21 per share.

(d) The quarters ended September 30, 2001, December 31, 2001, and December 31, 2002, include impairments of oil and gas properties of $10.7 million ($6.5 million net of tax, or 10 cents per share), $18.3 million ($11.3 million net of tax, or 18 cents per share) and $98.7 million ($57.7 million net of tax, or 91 cents per share), respectively.

## 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, 2002, 2001 and 2000. The Company began operations in Canada in December 2000. 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).

| | 2002 | | | | | |
|---|---|---|---|---|---|---|
| (In thousands) | U.S. | Canada | Argentina | Bolivia | Other | Total |
| Revenues | $ 219,511 | $ 113,808 | $ 232,787 | $ 12,344 | $ - | $ 578,450 |
| Production (lifting) costs | 88,043 | 45,113 | 66,809 | 4,328 | - | 204,293 |
| Exploration costs | 10,679 | 19,792 | - | - | 12,263 | 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 | 52,791 | (106,395) | 119,911 | 4,452 | (12,263) | 58,496 |
| Income tax expense (benefit) | 20,536 | (44,814) | 35,164 | 1,113 | (4,292) | 7,707 |
| Results of operations (excluding corporate overhead and interest costs) | $ 32,255 | $ (61,581) | $ 84,747 | $ 3,339 | $ (7,971) | $ 50,789 |

| | 2001 | | | | | |
|---|---|---|---|---|---|---|
| (In thousands) | U.S. | Canada | Argentina | Bolivia | Other | Total |
| Revenues | $ 359,471 | $ 86,277 | $ 243,329 | $ 17,648 | $ - | $ 706,725 |
| Production (lifting) costs | 106,680 | 32,567 | 61,018 | 4,385 | - | 204,650 |
| Exploration costs | 12,789 | 5,645 | - | - | 3,153 | 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 | 170,021 | (22,902) | 137,459 | 8,230 | (3,153) | 289,655 |
| Income tax expense (benefit) | 66,138 | (8,112) | 41,238 | 2,058 | (1,104) | 100,218 |
| Results of operations (excluding corporate overhead and interest costs) | $ 103,883 | $ (14,790) | $ 96,221 | $ 6,172 | $ (2,049) | $ 189,437 |

| (In thousands) | 2000 U.S. | Canada | Argentina | Bolivia | Other | Total |
|---|---|---|---|---|---|---|
| Revenues | $ 348,305 | $ 2,281 | $ 281,334 | $ 19,535 | $ - | $ 651,455 |
| Production (lifting) costs | 96,386 | 503 | 52,856 | 3,777 | - | 153,522 |
| Exploration costs | 4,271 | 152 | - | 12,133 | 6,121 | 22,677 |
| Impairment of proved properties | 225 | - | - | - | - | 225 |
| Depreciation, depletion and amortization | 53,184 | 586 | 33,077 | 7,421 | - | 94,268 |
| Results of operations before income taxes | 194,239 | 1,040 | 195,401 | (3,796) | (6,121) | 380,763 |
| Income tax expense (benefit) | 75,559 | 447 | 68,390 | (949) | (2,142) | 141,305 |
| Results of operations (excluding corporate overhead and interest costs) | $ 118,680 | $ 593 | $ 127,011 | $ (2,847) | $ (3,979) | $ 239,458 |

*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, 2002 and 2001, was as follows:

| (In thousands) | 2002 U.S. | Canada | Argentina | Bolivia | 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 | 16,182 | 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 | $ 16,182 | $ 1,468,770 |

| (In thousands) | 2001 U.S. | Canada | Argentina | Bolivia | Other | Total |
|---|---|---|---|---|---|---|
| Unproved properties not being amortized | $ 19,188 | $ 60,393 | $ - | $ - | $ 20,427 | $ 100,008 |
| Proved properties being amortized | 919,399 | 647,888 | 652,832 | 114,429 | 36 | 2,334,584 |
| Total capitalized costs | 938,587 | 708,281 | 652,832 | 114,429 | 20,463 | 2,434,592 |
| Less accumulated depreciation, depletion and amortization | 506,719 | 70,271 | 177,414 | 20,857 | - | 775,261 |
| Net capitalized costs | $ 431,868 | $ 638,010 | $ 475,418 | $ 93,572 | $ 20,463 | $ 1,659,331 |

Net capitalized costs for the Company's discontinued operations in Ecuador as of December 31, 2002 and 2001, were approximately $58.8 million and $49.7 million, respectively. Net capitalized costs for the Company's discontinued operations in Trinidad as of December 31, 2001, were approximately $7.9 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 2002, 2001 and 2000:

| | 2002 | | | | | |
|---|---|---|---|---|---|---|
| (In thousands) | U.S. | Canada | Argentina | Bolivia | Other | Total |
| Acquisitions: | | | | | | |
| Undeveloped properties | $ 1,981 | $ 2,690 | $ - | $ - | $ 390 | $ 5,061 |
| Producing properties | - | - | - | - | - | - |
| Exploratory | 15,748 | 21,872 | - | - | 7,395 | 45,015 |
| Development | 11,758 | 34,070 | 19,008 | 2,625 | - | 67,461 |
| Total costs incurred | $ 29,487 | $ 58,632 | $ 19,008 | $ 2,625 | $ 7,785 | $ 117,537 |

| | 2001 | | | | | |
|---|---|---|---|---|---|---|
| (In thousands) | U.S. | Canada | Argentina | Bolivia | Other | Total |
| Acquisitions: | | | | | | |
| Undeveloped properties | $ 1,455 | $ 59,033 | $ - | $ - | $ 338 | $ 60,826 |
| Producing properties | 2,506 | 562,444 | 42,267 | - | - | 607,217 |
| Exploratory | 20,963 | 24,839 | - | - | 2,700 | 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 | $ 3,073 | $ 874,337 |

| | 2000 | | | | | |
|---|---|---|---|---|---|---|
| (In thousands) | U.S. | Canada | Argentina | Bolivia | Other | Total |
| Acquisitions: | | | | | | |
| Undeveloped properties | $ 2,176 | $ 3,614 | $ - | $ 225 | $ 450 | $ 6,465 |
| Producing properties | 6,035 | 47,927 | 43,428 | - | - | 97,390 |
| Exploratory | 23,841 | 212 | - | 27,532 | 19,682 | 71,267 |
| Development | 32,072 | 1,035 | 49,457 | 983 | - | 83,547 |
| Total costs incurred | $ 64,124 | $ 52,788 | $ 92,885 | $ 28,740 | $ 20,132 | $ 258,669 |

Costs incurred for the Company's discontinued operations in Ecuador for 2002 and 2001 were approximately $12.2 million and $11.4 million, respectively, and were a credit of approximately $3.4 million for 2000 due to certain post-closing adjustments on property acquisitions made in 1999. Costs incurred for the Company's discontinued operations in Trinidad for 2002 were zero and were approximately $5.7 million and $2.4 million for 2001 and 2000, respectively.

*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, 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 | Ecuador | Trinidad | Total |
| Proved reserves at December 31, 1999 | 110,442 | - | 136,471 | 8,081 | 48,196 | - | 303,190 |
| Revisions of previous estimates | 397 | - | 18,501 | (1,125) | 2,540 | - | 20,313 |
| Extensions, discoveries and other additions | 329 | - | - | - | - | - | 329 |
| Production | (9,044) | (19) | (9,406) | (131) | (1,261) | - | (19,861) |
| Purchase of reserves-in-place | 447 | 2,407 | 11,970 | - | - | - | 14,824 |
| Sales of reserves-in-place | (235) | - | - | - | - | - | (235) |
| 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 |
| Proved developed oil reserves at: | | | | | | | |
| December 31, 2000 | 90,774 | 1,558 | 94,191 | 5,668 | 3,915 | - | 196,106 |
| 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 |

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

| | Gas (MMcf) | | | | | | Total |
|---|---|---|---|---|---|---|---|
| | U.S. | Canada | Argentina | Bolivia | Trinidad | Total | (MBOE) |
| Proved reserves at December 31, 1999 | 361,025 | - | 113,636 | 514,328 | - | 988,989 | 468,022 |
| Revisions of previous estimates | 39,123 | - | 13,990 | (41,521) | - | 11,592 | 22,245 |
| Extensions, discoveries and other additions | 34,990 | - | - | - | - | 34,990 | 6,160 |
| Production | (35,764) | (312) | (8,705) | (8,948) | - | (53,729) | (28,816) |
| Purchase of reserves-in-place | 1,376 | 39,790 | 2,278 | - | - | 43,444 | 22,065 |
| Sales of reserves-in-place | (2,078) | - | - | - | - | (2,078) | (581) |
| 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 |
| Proved developed gas reserves at: | | | | | | | |
| December 31, 2000 | 333,453 | 33,405 | 41,822 | 385,623 | - | 794,303 | 328,490 |
| 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 |

### *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, 2002 and 2001 (in thousands):

| | 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 |

| | 2001 | | | | | | |
|---|---|---|---|---|---|---|---|
| | U.S. | Canada | Argentina | Bolivia | Ecuador | Trinidad | Total |
| Future cash inflows | $ 2,131,498 | $ 930,656 | $ 2,885,530 | $ 450,358 | $ 528,726 | $ 78,730 | $ 7,005,498 |
| Future production costs | 929,408 | 299,818 | 1,152,217 | 47,277 | 242,802 | 43,949 | 2,715,471 |
| Future development and abandonment costs | 231,237 | 73,795 | 340,597 | 50,950 | 169,440 | 5,139 | 871,158 |
| Future net cash inflows before income tax expense | 970,853 | 557,043 | 1,392,716 | 352,131 | 116,484 | 29,642 | 3,418,869 |
| Future income tax expense | 271,409 | 141,784 | 323,109 | 80,911 | 11,339 | 11,966 | 840,518 |
| Future net cash flows | 699,444 | 415,259 | 1,069,607 | 271,220 | 105,145 | 17,676 | 2,578,351 |
| 10 percent annual discount for estimated timing of cash flows | 296,603 | 143,552 | 484,570 | 147,612 | 54,639 | 13,234 | 1,140,210 |
| Standardized Measure of discounted future net cash flows | $ 402,841 | $ 271,707 | $ 585,037 | $ 123,608 | $ 50,506 | $ 4,442 | $ 1,438,141 |

***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 2002, 2001 and 2000 (in thousands):

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Standardized Measure - beginning of year | $ 1,438,141 | $2,951,121 | $ 2,247,237 |
| Increases (decreases) - | | | |
| Sales, net of production costs | (406,443) | (517,835) | (522,545) |
| Net change in sales prices, net of production costs | 2,218,644 | (2,404,154) | 1,131,540 |
| Discoveries and extensions, net of related future development and production costs | 196,774 | 83,976 | 148,727 |
| Changes in estimated future development costs | 13,094 | (123,254) | (87,127) |
| Development costs incurred | 75,186 | 163,122 | 93,276 |
| Revisions of previous quantity estimates | 159,423 | (8,646) | 267,178 |
| Accretion of discount | 190,427 | 433,862 | 298,963 |
| Net change in income taxes | (787,133) | 911,566 | (645,108) |
| Purchase of reserves-in-place | - | 368,552 | 278,740 |
| Sales of reserves-in-place | (11,008) | (141,509) | (4,787) |
| Timing of production of reserves and other | (340,848) | (278,660) | (254,973) |
| Standardized Measure - end of year | $ 2,746,257 | $ 1,438,141 | $ 2,951,121 |

14. Subsequent Event (unaudited)

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, representing approximately 95.1% 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 in exchange for the tendered options. Restricted stock award compensation expense of approximately $5.5 million (based on the stock price on the date of grant) will be amortized over the vesting periods.

Had the offer to exchange described above been completed as of December 31, 2002:

(a) Awards for a total of 2,057,937 shares of common stock would remain available for grant under the 1990 Plan;

(b) Outstanding stock options at December 31, 2002, would have been for 3,322,736 shares at a weighted average exercise price of $10.61 per share, of which options for 3,137,070 shares would have been exercisable at December 31, 2002, at a weighted average exercise price of $10.26 per share;

(c) Of the 2,256,500 options with exercise prices between $19.28 and $22.94 per share at December 31, 2002, prior to the offer to exchange, only 138,500 options would have remained outstanding at exercise prices ranging from $19.28 to $22.94 per share, with a weighted average exercise price of $20.19 per share and a weighted average contractual life of 4.4 years (39,833 of these options would have been exercisable currently at a weighted average exercise price of $20.13 per share); and

(d) Restricted stock awards outstanding at December 31, 2002, would have totaled 953,624 shares.

# Company Information

## Annual Stockholders' Meeting

Our annual stockholders' meeting will be held Tuesday, May 13, 2003, at 10:00 a.m. (CDT), Bank of Oklahoma Tower, Ninth Floor, One Williams Center, Tulsa, Oklahoma.

## Independent Auditors

Ernst & Young LLP

## Independent Reserve Engineers

Netherland, Sewell & Associates, Inc.
DeGolyer and MacNaughton
Outtrim Szabo Associates Ltd.

## Stock Market Information

The company's common stock is traded on the New York Stock Exchange under the symbol VPI. The table below reflects the high and low sales prices per share during each quarter of 2002 and 2001.

| | 2002 | | 2001 | |
|---|---|---|---|---|
| | High | Low | High | Low |
| March 31 | $14.70 | $ 7.85 | $22.81 | $18.44 |
| June 30 | $14.96 | $10.61 | $22.20 | $18.02 |
| September 30 | $11.80 | $ 8.10 | $20.25 | $14.75 |
| December 31 | $11.50 | $ 8.32 | $18.95 | $11.77 |

The company's quarterly cash dividend of 3½ cents per share on March 14, 2002, was increased to 4 cents per share on May 14, 2002.

## Corporate Office

110 West Seventh Street
Tulsa, OK 74119
Telephone: 918-592-0101

## Investor Contact

Robert E. Phaneuf
Vice President – Corporate Development
Telephone: 918-592-0101

## Transfer Agent and Registrar

Stockholders should refer specific questions concerning their stock certificates, in writing, directly to the Transfer Agent and Registrar, or by calling toll free 1-800-526-0801:

Mellon Investor Services LLC
88 Challenger Road
Overpeck Centre
Ridgefield Park, NJ 07660
www.melloninvestor.com

Design by Falk Harrison Creative, St. Louis, Missouri www.falkharrison.com

VINTAGE PETROLEUM, INC.

110 West Seventh Street
Tulsa, OK 74119
918-592-0101

www.vintagepetroleum.com