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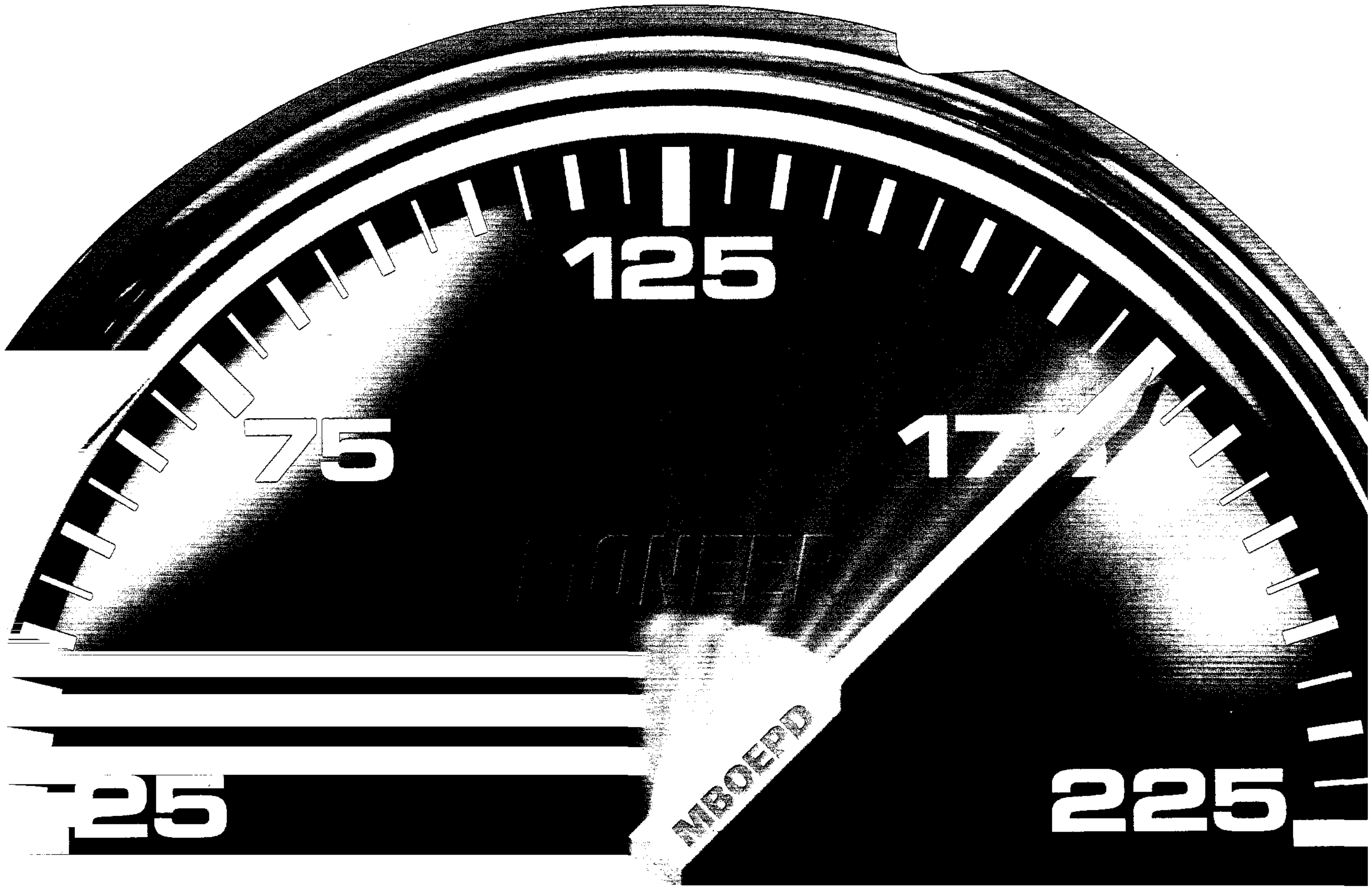
REVVING UP

PIONEER NATURAL RESOURCES Co.

2001 Annual Report



Fellow Shareholders:

Over the past five years, we've transformed Pioneer into a top-tier exploration and production company with the financial and operational strength capable of offering shareholders above-average returns. We've formed a very talented team of people and have guidelines in place that require that projects meet or exceed our investment return hurdles. In the 2000 Annual Report, we emphasized our strategy, outlined our successes and stated that our plan was to stay the course as we developed those successes for first production and cash flow in 2002 and 2003.

Today, we are proud to report that we are on course with the development of four high-impact projects, we have drilled six new discoveries that we expect to develop or appraise in 2002, and we have several new prospects drilling and ready to drill. With the power provided by our high-quality asset base, we have funded these growth opportunities while maintaining relatively steady production from our core onshore properties and gaining considerable financial strength. We are gaining momentum.

Our common stock has significantly outperformed the peer group average over the last three years, and we are nearing first production on five discoveries expected to increase our daily production 55% to 60% between early 2002 and mid-2003.

2001 RESULTS

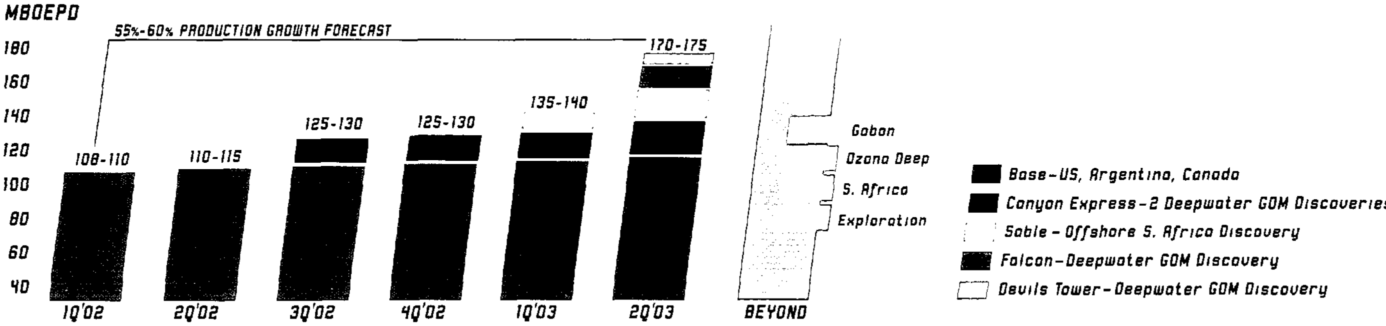
Although our common stock price declined 2% during 2001, it held up relatively well under the pressure of falling oil and gas prices and declines in the overall stock market. The stock prices of our peer group fell an average of 22%, and we believe Pioneer's stock price performance reflects our strong exploration and development program and the value protection from our oil and gas hedge position.

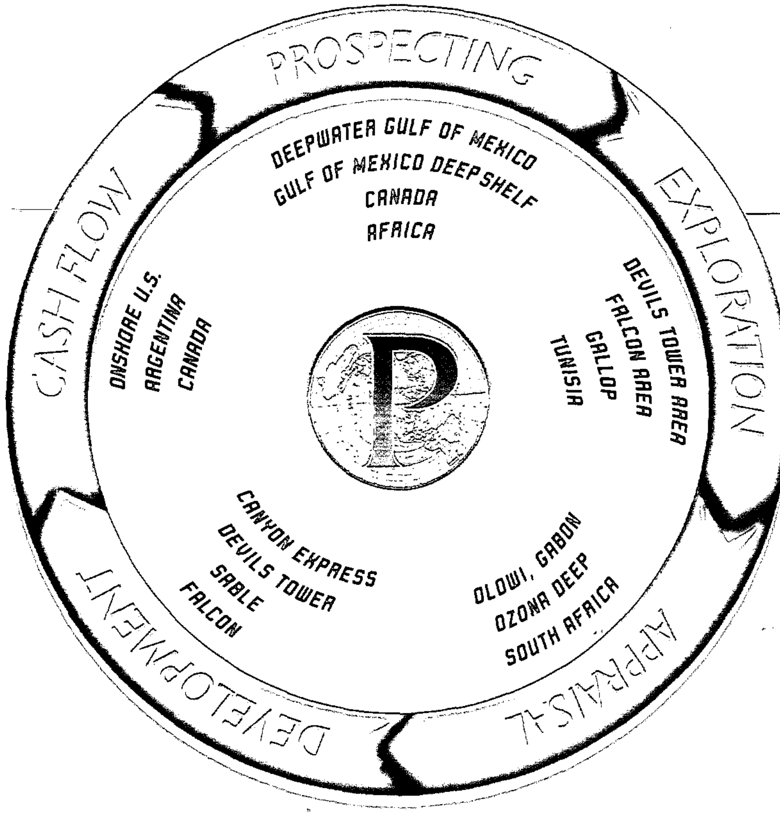
North American gas demand fell during 2001 creating an excess supply of gas in storage and lowering its market price. We believe the outlook for an increase in the price of gas is favorable. Demand is expected to increase and supply should decline as a result of the reduction in the number of gas wells being drilled. While the price of oil has declined from last year's highs, the Organization of Petroleum Exporting Countries (OPEC) has succeeded in stabilizing worldwide oil prices at levels above the ten-year historical average.

Despite the decline in oil and gas prices, we posted strong financial and operating results for 2001. These results are thoroughly covered in the accompanying Form 10-K; however, we have summarized some of our most significant achievements below:

- Reported net income of $100 million or $1.00 per diluted share
- Generated $476 million of cash flow from operations
- Produced 42 million barrels of oil equivalent (BOE) reserves
- Added 86 million BOE of proved oil and gas reserves
- Posted three-year reserve replacement of 184% at $4.74 per BOE
- Drilled 390 wells with 85% success, including 101 exploration and extension wells with 60% success
- Acquired additional interest in Devils Tower, Aconcagua and Canyon Express, and the Spraberry field
- Reduced long-term debt to book equity ratio to 55% from 64% at prior year-end
- Reduced long-term debt to $2.35 per barrel of oil equivalent proved reserves
- Repurchased 830,400 common shares at an average price of $15.69 per share
- Built a portfolio of oil and gas price hedges valued at $181 million at year end

DAILY PRODUCTION FORECAST
MBOEPD





We had a strong year with the drillbit, discovering six new fields in the Gulf of Mexico, Gabon and South Africa that we plan to appraise or develop this year. We began the development of our "Big 4" discoveries (Canyon Express, Devils Tower and Falcon in the deepwater Gulf of Mexico and Sable offshore South Africa) and the development wells drilled to date have exceeded expectations, moving them toward first production over the next 14 months. We also entered Tunisia as a new exploration area and added 24 new leasehold blocks in the Gulf of Mexico.

2001 DISCOVERIES

- Falcon, gas discovery in the deepwater Gulf of Mexico
- Ozona Deep, oil discovery in the deepwater Gulf of Mexico
- Olowi, oil discovery in the shallow water offshore Gabon
- Boomslang and EBB #2, two discoveries offshore South Africa
- Stirrup, deep gas discovery on the Gulf of Mexico shelf
- Oneida, deep gas discovery on the Gulf of Mexico shelf

2002 GAINING MOMENTUM

We have budgeted $375 million of capital expenditures for 2002, down from 2001 but in line with our expected discretionary cash flow. Approximately $180 million is allocated to complete the development of our "Big 4" projects. Approximately $105 million is planned to be invested to develop onshore core properties in the U.S., Canada and Argentina, and we plan to continue our exploration program with $90 million of capital. We use commodity price hedging to lock in returns and stabilize cash flow and have protected a significant portion of 2002 cash flow from possible declines in oil and gas prices.

We are nearing first production on our "Big 4" discoveries, which drive our 55% to 60% production growth forecast. Canyon Express is progressing toward first production this summer, and Sable, Devils Tower and Falcon are on track for early 2003 startup.

We are drilling a second prospect offshore Gabon to test the oil rim on the southern section of the feature and plan to drill two wells to appraise the discovery well we drilled in 2001. We also plan to drill two exploration wells in South Africa and two to three exploration wells on our new permits in Tunisia.

In the deepwater Gulf of Mexico, we plan to appraise our discovery at Ozona Deep and test prospects near both Falcon and Devils Tower to take advantage of the new infrastructure currently under development in those areas. On the Gulf of Mexico deep shelf, we plan to test the Gallop prospect, on trend with the Stirrup field we discovered in 2001.

The majority of our development efforts are directed toward the "Big 4," but we will continue to develop our core onshore properties in the U.S., Canada and Argentina. We are drilling development wells in the onshore U.S. and Canada. We continue to monitor the political and economic environment in Argentina and believe that conditions will stabilize and allow us to continue to profitably develop our Argentina properties.

We are very excited about the outlook for Pioneer, with significant projects in each phase of the exploration and development process. This is the year our patience, planning and execution begin to pay off in the form of substantial near-term production growth from our "Big 4" projects, and we are busy appraising and exploring other exciting prospects for longer-term growth. I want to thank you, our shareholders and employees, for your support. We are gaining momentum and, as I stated last year, we plan to stay the course.

Scott D. Sheffield

Scott D. Sheffield
Chairman, President and CEO

PROJECT REVIEW

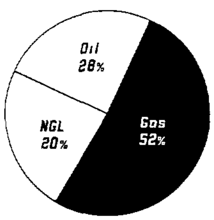
DEVELOPING FOR CASH FLOW

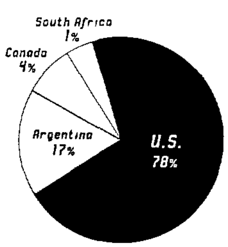
CANYON EXPRESS The Canyon Express is the largest North American gas project under development and combines production from three deepwater Gulf of Mexico discoveries, including Pioneer's Aconcagua and Camden Hills fields, developed with subsea wellheads tied back 55 miles to a shelf production platform. The project is being developed with a capacity to deliver 500 million cubic feet of gas per day by the summer of 2002. Pioneer owns a 23.5% interest in the Canyon Express project, which is expected to increase its North American gas production by 40% to 45% from early 2002 levels.

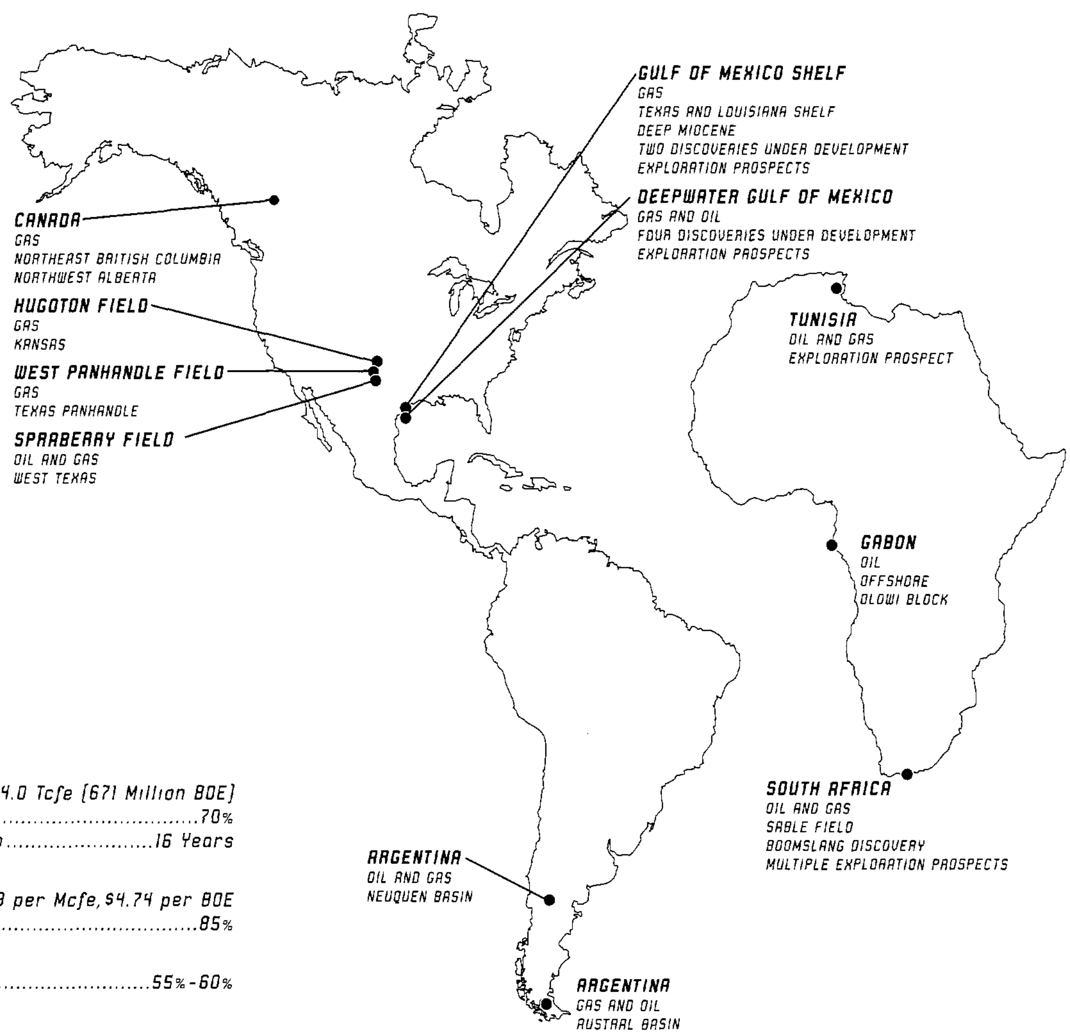
SABLE Pioneer's first well offshore South Africa confirmed the presence of commercial oil reserves resulting in the development of the Sable oil field. The field is being developed with a floating production, storage and offloading vessel (FPSO), and first production is expected in late 2002 or early 2003 at daily rates of 30 to 35 thousand barrels per day. With Pioneer's 40% working interest, its worldwide oil production is expected to increase more than 35% from current levels. The Company has also discovered oil and gas on its Boomslang prospect offshore South Africa and plans to drill two exploration wells during 2002 to further test prospects in the area.

PROVED RESERVES

4.0 TCFE/671 MILLION BOE







QUICK FACTS

Proved Reserves–12/31/01 .... 4.0 Tcfe [671 Million BOE]
Proved Developed 70%
Reserves / 2001 Production Ratio .... 16 Years

3 Year Average
Finding Cost .... $.79 per Mcfe, $4.74 per BOE
2001 Drilling Success 85%

Anticipated Production Growth:
Early 2002 to Mid 2003 .... 55%-60%

FALCON Pioneer discovered the Falcon field in the deepwater Gulf of Mexico in April of 2001. The exploratory well found two gas-bearing sands and was successfully sidetracked to a downdip location to test the extent of the reservoir. The Falcon field, located 100 miles east of Corpus Christi, was approved for development in October 2001 and will be produced via a two-well subsea development tied back to a host platform located on the shelf approximately 30 miles away. Pioneer expects first gas production in early 2003, with peak rates expected to reach 175 million cubic feet equivalent per day. Pioneer holds a 45% working interest in the field, and the Company's total North American gas production is expected to increase 25% to 30% from early 2002 levels when the project comes on stream.

DEVILS TOWER The Devils Tower discovery announced in February 2000 was Pioneer's second in the deepwater Gulf of Mexico. An appraisal well and an associated sidetracked location were also successful, and development of the field is underway with first production expected in the second quarter of 2003. The field will be developed using a truss spar with slots for eight dry tree wells and the flexibility to accommodate future subsea tie-backs. Pioneer's 25% working interest in field production is expected to increase the Company's current worldwide oil production by 25% to 30%.

Pioneer is also actively developing its onshore assets and other recent discoveries. The Stirrup field and the Oneida field, deep gas discoveries on the Gulf of Mexico shelf, are being developed for first production in 2002, and the Company plans to drill wells in the U.S. and Canada to further develop its core properties onshore.

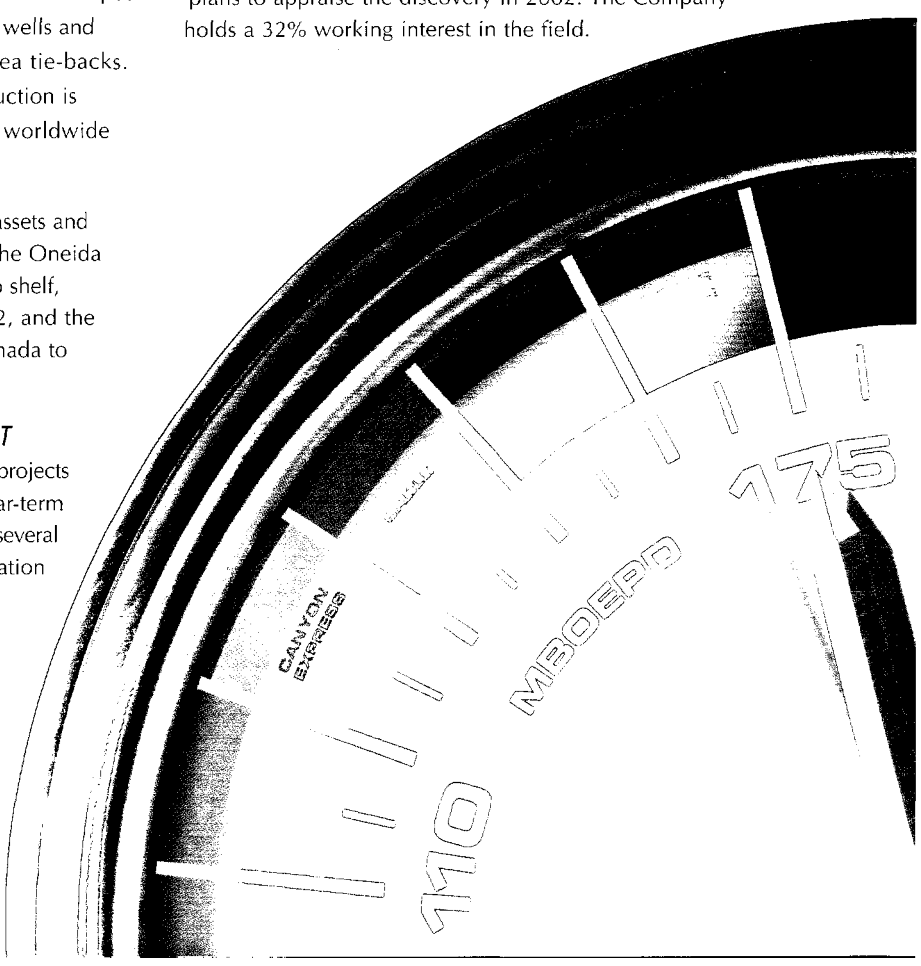
APPRAISING FOR POTENTIAL DEVELOPMENT

While achieving first production from the "Big 4" projects currently under development will have significant near-term impact to net income and cash flow, Pioneer also has several significant projects in the earlier phases of an exploration project's life cycle to support longer-term growth.

During 2001, the Company made new discoveries on the Olowi prospect offshore Gabon in West Africa, on the Ozona Deep prospect in the deepwater Gulf of Mexico and on its Block 9 prospects in South Africa. During 2002, Pioneer plans to appraise these discoveries and hopes to approve the projects for development by the end of the year. These projects, if successfully appraised and approved, have the potential to significantly impact production in 2004 and beyond.

Pioneer drilled its first well on its 315,000-acre Olowi block offshore Gabon, discovering the Olowi field in 2001. The field is three miles southeast of the 300-million-barrel Gamba oil field. The first well encountered a 75-foot oil column with excellent porosity, and Pioneer plans to drill three wells to further define and appraise the field in 2002. The Company holds a 100% working interest and is operator of the permit.

In October 2001, the Ozona Deep field was discovered in the deepwater Gulf of Mexico in over 3,000 feet of water and encountered approximately 345 feet of net oil pay. The field is near existing infrastructure providing several alternatives for future development, and Pioneer plans to appraise the discovery in 2002. The Company holds a 32% working interest in the field.



Two discoveries were drilled on Pioneer's acreage in Block 9 offshore South Africa. The Boomslang discovery encountered significant oil and gas, and the E-BB#2 well drilled in the center of the basin to assess potential deliverability and reservoir limits also encountered significant gas. The Company is evaluating the commercial viability of providing gas to a synthetic fuels plant onshore and plans to drill two wells to test similar oil and gas prospects during 2002.

EXPLORING FOR THE FUTURE

Pioneer plans to focus its exploration efforts in six areas during 2002. Offshore Gabon in West Africa, Pioneer plans to drill an exploration well to test a southern extension of the Olowi discovery. Pioneer plans to drill two to three Silurian and TAGI sand prospects in Tunisia in North Africa, and the Company will continue to explore its extensive acreage position offshore South Africa, planning two wells to test oil and gas prospects refined with information from new 3-D seismic data surveys. On the Gulf of Mexico shelf, Pioneer plans to test at least two deep gas prospects including the Gallop prospect which is on trend with the Stirrup field discovered in 2001 and currently being developed for first production in the second quarter of 2002. To take advantage of the infrastructure being developed for its discoveries in the deepwater Gulf of Mexico, Pioneer plans to drill exploration wells on at least two prospects near its Falcon discovery and one prospect near its Devils Tower discovery.

PROSPECTING TO REFILL THE PIPELINE

To keep the pipeline of opportunities full, Pioneer's geoscientists continually pursue new prospects utilizing the Company's extensive seismic database. During 2001, Pioneer acquired leases on 24 new acreage blocks in the Gulf of Mexico, 15 in the deepwater and nine on the shelf, acquired leases on 3.8 million acres in Tunisia, and invested in new 3-D seismic data. Pioneer plans to continue to focus its exploration efforts in the Gulf of Mexico and Africa and is expanding its exploration program to include Canada where it has historically focused on developing existing fields.

POWERING GROWTH

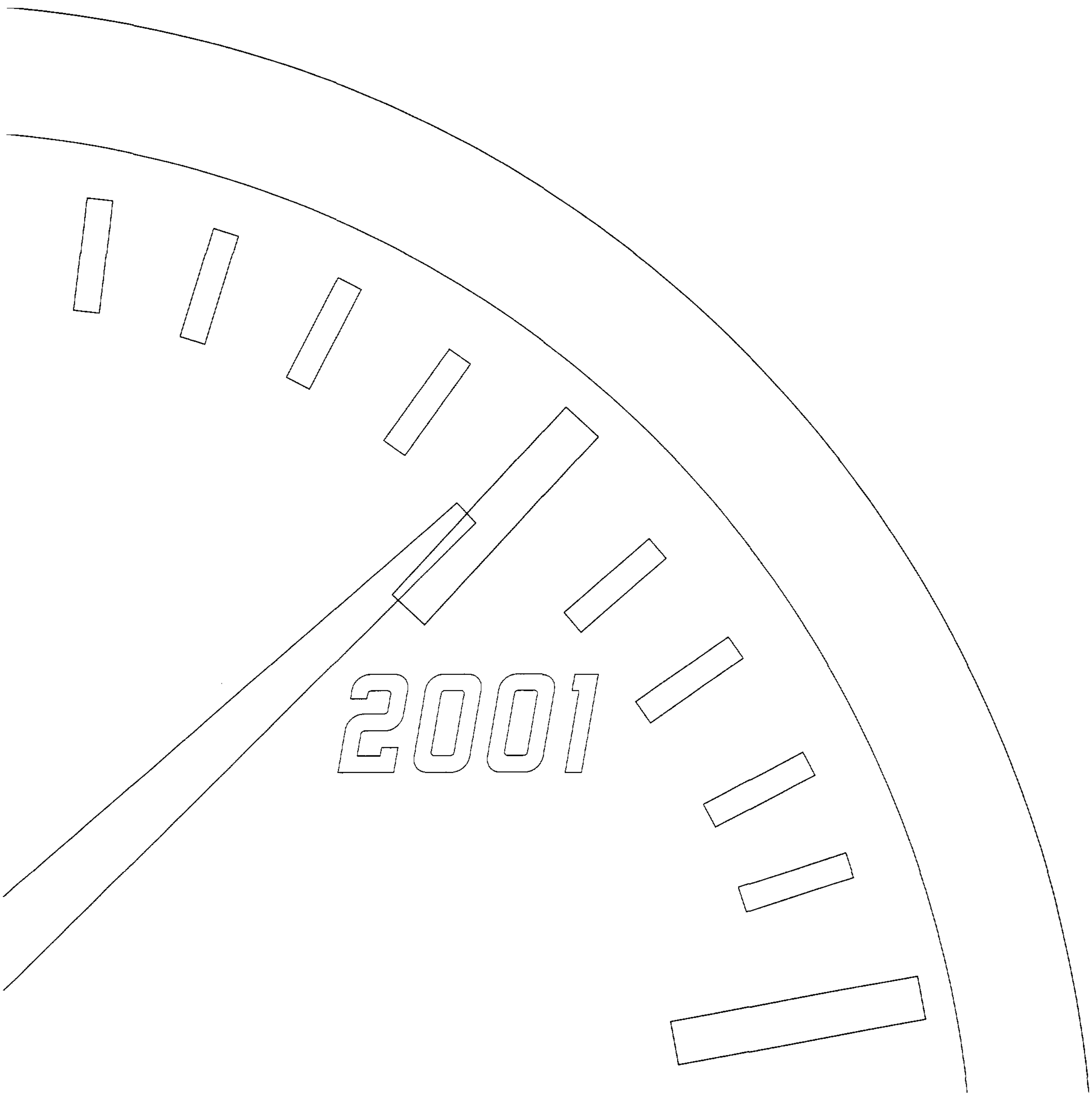
Pioneer's high-quality asset base provides the power for the Company's growth. Pioneer's asset base is highly concentrated in a few fields in the U.S., Canada and Argentina, allowing for focused, efficient operations and development drilling. These core properties offer an extensive inventory of development drilling opportunities to maintain or increase production. With above-average productive lives, Pioneer's core properties offer stability and require less reinvestment to maintain production, providing excess cash flow to fuel growth.

ONSHORE U.S. Pioneer's onshore U.S. holdings are concentrated in three key fields: the long-lived Hugoton and West Panhandle gas fields and the Spraberry oil and gas field. These fields represent approximately 64% of the Company's reserve base and have remaining productive lives of over 40 years. These fields are the primary fuel for the Company's growth, providing strong cash flow and opportunities for continued development.

CANADA Pioneer's Canadian activities focus on its core area in northeast British Columbia and just across the border into Alberta. Pioneer's acreage is strategically located at the northern end of the Alliance Pipeline which delivers Canadian gas directly to the Chicago market. Pioneer drills development wells each winter to enhance its production and is expanding its exploration program into Canada, with several exploration wells planned during the winter of 2002/2003.

ARGENTINA Pioneer's Argentine properties are concentrated in two prolific oil and gas producing provinces, the Neuquen and Austral basins, covering approximately two million acres. The Neuquen basin is relatively undeveloped, offering opportunities for exploitation and development. The Austral basin offers stable production combined with exploration opportunities. Early in 2002, Argentina devalued its currency, creating financial and political uncertainty and prompting Pioneer to limit its new investments in the country. The Company expects that, over time, the environment will improve allowing for continued profitable development of its Argentine oil and gas properties.

10-K



UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2001

Commission File Number: 1-13245

Pioneer Natural Resources Company
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**75-2702753** (I.R.S. Employer Identification No.)
5205 N. O'Connor Blvd., Suite 1400, Irving, Texas (Address of principal executive offices)	**75039** (Zip Code)

Registrant's telephone number, including area code:
(972) 444-9001

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

Title of each class	Name of each exchange on which registered
Common Stock	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 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. ✓

Aggregate market value of the voting stock held by non-affiliates of the Registrant as of February 25, 2002 . . . . $2,017,546,447

Number of shares of Common Stock outstanding as of February 25, 2002 104,052,756

Documents Incorporated by Reference:

(1) Proxy Statement for Annual Meeting of Shareholders to be held May 14, 2002 - Referenced in Part III of this report.

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PIONEER NATURAL RESOURCES COMPANY

CROSS REFERENCE SHEET
Pursuant to National Policy Statement No. 47 (Canada)
(Annual Information Form ("AIF"))

Item Number and Caption of AIF	Heading or Location in Form 10-K
1. Incorporation	Item 1. Business
2. General Development of the Business	Item 1. Business
3. Narrative Description of the Business	Item 1. Business Item 2. Properties
4. Selected Consolidated Financial Information	Item 6. Selected Financial Data Item 8. Financial Statements and Supplementary Data
5. Management's Discussion and Analysis	Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Item 7A. Quantitative and Qualitative Disclosures About Market Risk
6. Market for Securities	Item 5. Market for Registrant's Common Stock and Related Stockholder Matters
7. Directors and Officers	Item 10. Directors and Executive Officers of the Registrant
8. Additional Information	Item 10. Directors and Executive Officers of the Registrant Item 11. Executive Compensation Item 12. Security Ownership of Certain Beneficial Owners and Management Item 13. Certain Relationships and Related Transactions

Parts I and II of this annual report on Form 10-K (the "Report") contain forward looking statements that involve risks and uncertainties. Accordingly, no assurances can be given that the actual events and results will not be materially different than the anticipated results described in the forward looking statements. See "Item 1. Business - Competition, Markets and Regulation" and "Item 1. Business - Risks Associated with Business Activities" for a description of various factors that could materially affect the ability of Pioneer Natural Resources Company to achieve the anticipated results described in the forward looking statements.

Definitions of Oil and Gas Terms and Conventions Used Herein

Within this Report, the following oil and gas terms and conventions have specific meanings: "**Bbl**" means a standard barrel containing 42 United States gallons; "**Bcf**" means one billion cubic feet; "**Tcf**" means one trillion cubic feet; "**Bcfe**" means a billion cubic feet equivalent and is a standard convention used to express oil and gas volumes on a comparable gas equivalent basis; "**BOE**" means a barrel of oil equivalent and is a standard convention used to express oil and gas volumes on a comparable oil equivalent basis; "**Btu**" means British thermal; "**MMBtu**" means one million Btu's; "**MBbl**" means one thousand Bbls; "**MBOE**" means one thousand BOE; "**MMBOE**" means one million BOE; "**Mcf**" means one thousand cubic feet and is a measure of natural gas volume; "**MMcf**" means one million cubic feet; "**NGL**" means natural gas liquid; "**NYMEX**" means The New York Mercantile Exchange; "**proved reserves**" mean the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

"**Standardized Measure**" means the after-tax present value of estimated future net revenues of proved reserves, determined in accordance with the rules and regulations of the United States Securities and Exchange Commission (the "**SEC**"), using prices and costs in effect at the specified date and a 10 percent discount rate; "**acquisition and finding cost per BOE**" means total costs incurred divided by the summation of proved reserves attributable to revisions of previous estimates, purchases of minerals in place and new discoveries and extensions; "**reserve replacement percentage**" means, expressed as a percentage, the summation of annual proved reserves, on a BOE basis, attributable to revisions of previous estimates, purchases of minerals in place and new discoveries and extensions divided by annual production of oil, NGLs and gas, on a BOE basis; and "**WTI**" means West Texas Intermediate and is a benchmark grade of oil in the United States.

Gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of gas to 1.0 Bbl of oil or NGL.

With respect to information on the working interest in wells, drilling locations and acreage, "**net**" wells, drilling locations and acres are determined by multiplying "gross" wells, drilling locations and acres by Pioneer Natural Resources Company's working interest in such wells, drilling locations or acres. Unless otherwise specified, wells, drilling locations and acreage statistics quoted herein represent gross wells, drilling locations or acres; and, all dollar amounts are expressed in U.S. dollars.

PART I

ITEM 1. BUSINESS

General

Pioneer Natural Resources Company ("Pioneer", or the "Company") is a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange and Toronto Stock Exchange. Pioneer is an oil and gas exploration and production company with ownership interests in oil and gas properties located in the United States, Argentina, Canada, Gabon, South Africa and Tunisia.

The Company's executive offices are located at 5205 N. O'Connor Blvd., Suite 1400, Irving, Texas 75039; the Company's telephone number is (972) 444-9001. The Company maintains other offices in Midland, Texas; Buenos Aires, Argentina; Calgary, Canada; and Capetown, South Africa. At December 31, 2001, the Company had 926 employees, 469 of whom were employed in field and plant operations.

Mission and Strategies

The Company's mission is to provide shareholders with superior investment returns through strategies that maximize Pioneer's long-term profitability and net asset value. The strategies employed to achieve this mission are predicated on maintaining financial flexibility and capital allocation discipline. Historically, these strategies have been anchored by the Company's long-lived Spraberry oil field and Hugoton and West Panhandle gas fields' reserves and production. Underlying these fields are approximately 64 percent of the Company's proved oil and gas reserves which have a remaining productive life in excess of 40 years. The stable base of oil and gas production from these fields, together with the soon-to-be-realized production growth from the Company's 1998 Sable oil field discovery in South Africa, the 1999 Aconcagua, 2000 Devils Tower and 2001 Falcon discoveries in the deepwater Gulf of Mexico (the "Big 4"), will generate the operating cash flows that will provide Pioneer with continued financial flexibility. The Big 4 exploration successes represent the results of the Company's ability to selectively reinvest capital from the long-lived Spraberry, Hugoton and West Panhandle fields to areas offering superior investment returns. Similarly, the Company will continue to: (a) selectively explore for and develop proved reserve discoveries in areas that offer superior reserve growth and profitability potential; (b) invest in the personnel and technology necessary to maximize the Company's exploration and development successes, and (c) enhance liquidity, allowing the Company to take advantage of future exploration, development and acquisition opportunities. The Company is committed to continuing to enhance shareholder investment returns through adherence to these strategies.

Business Activities

The Company is an independent oil and gas exploration and development company. Pioneer's purpose is to competitively and profitably explore for, develop and produce oil, NGL and gas reserves. In so doing, the Company sells homogenous oil, NGL and gas units which, except for geographic and relatively minor qualitative differentials, cannot be significantly differentiated from units offered for sale by the Company's competitors. Competitive advantage is gained in the oil and gas exploration and development industry through superior capital investment decisions, technological innovation and price and cost management.

Petroleum industry. The petroleum industry has been characterized by volatile oil, NGL and gas commodity prices and relatively stable supplier costs during the three years ended December 31, 2001. During 1999 and 2000, the Organization of Petroleum Exporting Countries and certain other oil exporting nations reduced their oil export volumes. Those reductions in oil export volumes had a positive impact on world oil prices, as did overall gas supply and demand fundamentals on North American gas prices. During 2001, world oil and North American gas supply and demand fundamentals shifted, primarily as a result of an economic recession curtailing demand, causing reductions in world oil and North American gas prices. To mitigate the impact of volatile commodity prices on the Company's net asset value, Pioneer periodically enters into commodity hedge contracts. See Note H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the impact to oil and gas revenues during 2001, 2000 and 1999 from the Company's hedging activities and the Company's open hedge positions at December 31, 2001 and related prices.

The Company. The Company's asset base is anchored by the Spraberry oil field located in West Texas, the Hugoton gas field located in Southwest Kansas and the West Panhandle gas field located in the Texas Panhandle. Complementing these areas, the Company has exploration and development opportunities and oil and gas production activities in the United States Gulf of Mexico and onshore Gulf Coast areas, and internationally in Argentina, Canada, Gabon, South Africa and Tunisia. Combined, these assets create a portfolio of resources and opportunities that are well balanced among oil, NGLs and gas; and that are also well balanced between long-lived, dependable production and exploration and development opportunities. Additionally, the Company has a team of dedicated employees that represent the professional disciplines and sciences that will allow Pioneer to maximize the long-term profitability and net asset value inherent in its physical assets.

The Company provides administrative, financial and management support to United States and foreign subsidiaries that explore for, develop and produce oil, NGL and gas reserves. Production operations are principally located domestically in Texas, Kansas, Louisiana and the Gulf of Mexico, and internationally in Argentina and Canada.

Production. The Company focuses its efforts towards maximizing its average daily production of oil, NGL and gas through development drilling, production enhancement activities and acquisitions of producing properties while minimizing the controllable costs associated with the production activities. During 2001, 2000 and 1999, the Company's average daily oil, NGL and gas production decreased primarily as a result of oil and gas property divestitures that were supportive of the Company's debt reduction goal. Production, price and cost information with respect to the Company's properties for each of 2001, 2000 and 1999 is set forth under "Item 2. Properties - Selected Oil and Gas Information - Production, Price and Cost Data".

Drilling activities. The Company seeks to increase its oil and gas reserves, production and cash flow through exploratory and development drilling and by conducting other production enhancement activities, such as well recompletions. During the five years ended December 31, 2001, the Company drilled 2,150 gross (1,510.2 net) wells, 90 percent of which were successfully completed as productive wells, at a total cost (net to the Company's interest) of $1.5 billion. During 2001, the Company drilled 390 gross (252.1 net) wells for a total cost (net to the Company's interest) of approximately $423.6 million, 60 percent of which was spent on development wells and related facilities. The Company's current 2002 capital expenditure budget is $375 million, which represents a spending decrease of approximately 42 percent from 2001 total costs incurred for oil and gas production activities. The Company has allocated the budgeted 2002 capital expenditures as follows: $285 million to development drilling and facility activities, and $90 million to exploration activities.

The Company believes that its current property base provides a substantial inventory of prospects for future reserve, production and cash flow growth. The Company's proved reserves as of December 31, 2001 include proved undeveloped reserves and proved developed reserves that are behind pipe and that require future capital expenditures, of 104.4 million Bbls of oil and NGLs and 659 Bcf of gas. The timing of the development of these reserves will be dependent upon the commodity price environment, the Company's expected operating cash flows and the Company's financial condition. The Company believes that its current portfolio of undeveloped prospects provides attractive development and exploration opportunities for at least the next three to five years.

Exploratory activities. Since 1998, the Company has devoted significant efforts and resources on hiring and developing a highly skilled exploration staff as well as acquiring and drilling a portfolio of exploration opportunities. The Company's commitment to exploration has resulted in significant discoveries during this time period, such as the 1998 Sable oil field discovery in South Africa and the 1999 Aconcagua, 2000 Devils Tower and 2001 Falcon discoveries in the deepwater Gulf of Mexico. During 2002, the Company plans to spend a higher percentage of its capital on the development of these high-impact projects (see "Item 2. Properties - Description of Properties"). Consequently, the Company currently anticipates that its 2002 exploration efforts will be reduced to approximately 23 percent of total budgeted 2002 expenditures and will be concentrated domestically in the Gulf of Mexico and the onshore Gulf Coast area, and internationally in Gabon, South Africa and Tunisia. Exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons than development drilling or enhanced recovery activities. See "Item 1. Business - Risks Associated with Business Activities - Drilling activities" below.

Asset divestitures. The Company regularly reviews its asset base for the purpose of identifying non-core assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. While the Company generally does not dispose of assets solely for the purpose of reducing debt, such dispositions can have the result of furthering the Company's objective of financial flexibility through reduced debt levels.

During 2001, 2000 and 1999, the Company's divestitures consisted of the sale of oil and gas properties and other assets for net proceeds of $113.5 million, $102.7 million and $420.5 million (of which $390.5 million in 1999 was cash proceeds), respectively, which resulted in 2001 and 2000 net divestiture gains of $7.7 million and $34.2 million, respectively, and a 1999 net divestiture loss of $24.2 million. The Company's 2001 net proceeds from asset divestitures were primarily derived from early termination of interest rate and commodity hedges, the sale of the Company's remaining investment in the common stock of a non-affiliated entity and the sale of certain non-strategic oil properties in Canada. The assets that the Company divested during 2000 were primarily comprised of an investment in a non-affiliated entity and non-core United States oil and gas properties located in Oklahoma, New Mexico and Louisiana. The Company's 1999 divestitures were comprised of non-core United States and Canadian oil and gas properties, gas plants and other assets. The net cash proceeds from the 2001, 2000 and 1999 asset dispositions were primarily used to reduce the Company's outstanding bank indebtedness. See Note K of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for specific information regarding the Company's asset divestitures.

The Company anticipates that it will continue to sell non-strategic properties from time to time to increase capital resources available for other activities, to achieve operating and administrative efficiencies and to improve profitability.

Acquisition activities. The Company regularly seeks to acquire properties that complement its operations, provide exploration and development opportunities and potentially provide superior returns on investment. In addition, the Company pursues strategic acquisitions that will allow the Company to expand into new geographical areas that feature producing properties and provide exploration/exploitation opportunities. During 2001, the Company expended $170.8 million of capital to acquire proved and unproved oil and gas properties. Excluding cash and other working capital acquired, the Company paid $92.9 million, through the issuance of common stock, to complete the agreement and plan of merger among Pioneer, Pioneer Natural Resources USA, Inc. and 42 Parker & Parsley limited partnerships (see Note E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data"). Additionally, $77.9 million was spent during 2001 to acquire additional working interests in the United States Gulf of Mexico Aconcagua discovery, the related Canyon Express gathering system and the Devils Tower project; 21 deep-water Gulf of Mexico blocks; 250,000 acres in the Anticlinal Campamento, Dos Hermanas and La Calera areas of the Neuquen Basin in Argentina; and a 30 percent interest in the Anaguid permit in the Ghadames basin onshore Southern Tunisia. During 2000, the Company expended $67.2 million to acquire proved and unproved oil and gas properties. Strategic acquisitions of proved properties during 2000 included incremental working interests in the United States Gulf of Mexico discovery at Devils Tower and the Company's Canadian Chinchaga gas field. The Company also acquired an interest in the Camden Hills Gulf of Mexico discovery and the related Canyon Express gathering system during 2000. During 1999, the Company acquired Argentine proved and unproved oil and gas properties that complement its existing operations in Argentina. The Company paid $38.8 million of cash for the Argentine assets during the fourth quarter of 1999.

The Company periodically evaluates and pursues acquisition opportunities (including opportunities to acquire particular oil and gas properties or related assets; entities owning oil and gas properties or related assets; and, opportunities to engage in mergers, consolidations or other business combinations with such entities) and at any given time may be in various stages of evaluating such opportunities. Such stages may take the form of internal financial analysis, oil and gas reserve analysis, due diligence, the submission of an indication of interest, preliminary negotiations, negotiation of a letter of intent or negotiation of a definitive agreement.

Operations by Geographic Area

The Company operates in one industry segment. During 2001, 2000 and 1999, the Company principally had oil and gas producing activities in the United States, Argentina and Canada; and, had exploration activities in the United States Gulf Coast area, the Gulf of Mexico, Argentina, Canada, Gabon, South Africa and Tunisia. See Note P of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for geographic operating segment information, including results of operations and segment assets.

Marketing of Production

General. Production from the Company's properties is marketed using methods that are consistent with industry practices. Sales prices for oil, NGL and gas production are negotiated based on factors normally considered in the industry, such as the spot price for gas or the posted price for oil, price regulations, distance from the well to the pipeline, well pressure, estimated reserves, commodity quality and prevailing supply conditions.

Significant purchasers. During 2001, the Company's primary purchaser of oil was ExxonMobil Corporation ("ExxonMobil"), the Company's primary purchaser of NGLs was Williams Energy Services ("Williams") and the Company's primary purchaser of gas was Anadarko Petroleum Corporation ("Anadarko"). Approximately seven percent, 11 percent and 10 percent of the Company's 2001 combined oil, NGL and gas revenues were attributable to sales to ExxonMobil, Williams and Anadarko, respectively. The Company is of the opinion that the loss of any one purchaser would not have an adverse effect on its ability to sell its oil, NGL and gas production.

Hedging activities. The Company periodically enters into commodity derivative contracts (swaps and collars) in order to (i) reduce the effect of the volatility of price changes on the commodities the Company produces and sells, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) lock in prices to protect the economics related to certain capital projects. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for a description of the Company's hedging activities, "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information concerning the impact to oil and gas revenues during 2001, 2000 and 1999 from the Company's hedging activities and the Company's open hedge positions at December 31, 2001 and related prices.

Competition, Markets and Regulation

Competition. The oil and gas industry is highly competitive. A large number of companies and individuals engage in the exploration for and development of oil and gas properties, and there is a high degree of competition for oil and gas properties suitable for development or exploration. Acquisitions of oil and gas properties have been an important element of the Company's growth. The Company intends to continue to acquire oil and gas properties that complement its operations, provide exploration and development opportunities and potentially provide superior return on investment. The principal competitive factors in the acquisition of oil and gas properties include the staff and data necessary to identify, investigate and purchase such properties and the financial resources necessary to acquire and develop them. Many of the Company's competitors are substantially larger and have financial and other resources greater than those of the Company.

Markets. The Company's ability to produce and market oil and gas profitably depends on numerous factors beyond the Company's control. The effect of these factors cannot be accurately predicted or anticipated. Although the Company cannot predict the occurrence of events that may affect oil and gas prices or the degree to which oil and gas prices will be affected, the prices for any oil or gas that the Company produces will generally approximate current market prices in the geographic region.

Governmental regulation. Oil and gas exploration and production operations are subject to various types of regulation by local, state, federal and foreign agencies. The Company's operations are also subject to state conservation laws and regulations, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from wells and the regulation of spacing, plugging and abandonment of wells. States and foreign governments generally impose a production or severance tax with respect to production and sale of oil and gas within their respective jurisdictions. The regulatory burden on the oil and gas industry increases the Company's cost of doing business and, consequently, affects its profitability.

Additional proposals and proceedings that might affect the oil and gas industry are considered from time to time by Congress, the Federal Energy Regulatory Commission, state regulatory bodies, the courts and foreign governments. The Company cannot predict when or if any such proposals might become effective or their effect, if any, on the Company's operations.

Environmental and health controls. The Company's operations are subject to numerous federal, state, local and foreign laws and regulations relating to environmental and health protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the type, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas and impose substantial liabilities for pollution resulting from oil and gas operations. These laws and regulations may also restrict air emissions or other discharges resulting from the operation of natural gas processing plants, pipeline systems and other facilities that the Company owns. Although the Company believes that compliance with environmental laws and regulations will not have a material adverse effect on its results of operations or financial condition, risks of substantial costs and liabilities are inherent in oil and gas operations, and there can be no assurance that significant costs and liabilities, including potential criminal penalties, will not be incurred. Moreover, it is possible that other developments, such as stricter environmental laws and regulations or claims for damages to property or persons resulting from the Company's operations, could result in substantial costs and liabilities.

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances released at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Company generates wastes, including hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The United States Environmental Protection Agency and various state agencies have limited the approved methods of disposal for certain hazardous and non-hazardous wastes. Furthermore, certain wastes generated by the Company's oil and gas operations that are currently exempt from treatment as "hazardous wastes" may in the future be designated as "hazardous wastes," and therefore be subject to more rigorous and costly operating and disposal requirements.

The Company currently owns or leases, and has in the past owned or leased, properties that for many years have been used for the exploration and production of oil and gas. Although the Company has used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under the Company's control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under such laws, the Company could be required to remove or remediate previously disposed wastes or property contamination or to perform remedial plugging operations to prevent future contamination.

Federal regulations require certain owners or operators of facilities that store or otherwise handle oil, such as the Company, to prepare and implement spill prevention control plans, countermeasure plans and facility response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Prevention Act of 1990 ("OPA") amends certain provisions of the federal Water Pollution Control Act of 1972, commonly referred to as the Clean Water Act

("CWA"), and other statutes as they pertain to the prevention of and response to oil spills into navigable waters. The OPA subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. The CWA provides penalties for any discharges of petroleum products in reportable quantities and imposes substantial liability for the costs of removing a spill. OPA requires responsible parties to establish and maintain evidence of financial responsibility to cover removal costs and damages resulting from an oil spill. OPA calls for a financial responsibility of $35 million to cover pollution cleanup for offshore facilities. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of releases of petroleum or its derivatives into surface waters or into the ground. The Company does not believe that the OPA, CWA or related state laws are any more burdensome to it than they are to other similarly situated oil and gas companies.

Many states in which the Company operates have recently begun to regulate naturally occurring radioactive materials ("NORM") and NORM wastes that are generated in connection with oil and gas exploration and production activities. NORM wastes typically consist of very low-level radioactive substances that become concentrated in pipe scale and in production equipment. State regulations may require the testing of pipes and production equipment for the presence of NORM, the licensing of NORM-contaminated facilities and the careful handling and disposal of NORM wastes. The Company believes that the growing regulation of NORM will have a minimal effect on the Company's operations because the Company generates only a very small quantity of NORM on an annual basis.

The Company does not believe that its environmental risks are materially different from those of comparable companies in the oil and gas industry. Nevertheless, no assurance can be given that environmental laws will not, in the future, result in a curtailment of production or processing or a material increase in the costs of production, development, exploration or processing or otherwise adversely affect the Company's results of operations and financial condition.

The Company employs an environmental manager and environmental specialists charged with monitoring environmental and regulatory compliance. The Company performs an environmental review as part of the due diligence work on potential acquisitions, including acquisitions of oil and gas properties. The Company is not aware of any material environmental legal proceedings pending against it or any material environmental liabilities to which it may be subject.

Risks Associated with Business Activities

The nature of the business activities conducted by the Company subjects it to certain hazards and risks. The following is a summary of some of the material risks relating to the Company's business activities.

Commodity prices. The Company's revenues, profitability, cash flow and future rate of growth are highly dependent on prices of oil and gas, which are affected by numerous factors beyond the Company's control. Oil and gas prices historically have been very volatile. Commodity prices were favorable during 2000 and the first quarter of 2001, but have since trended downwards. A significant downward trend in commodity prices, comparable to the commodity prices experienced in 1998, would have a material adverse effect on the Company's revenues, profitability and cash flow and could, under certain circumstances, result in a reduction in the carrying value of the Company's oil and gas properties and an increase in the Company's deferred tax asset valuation allowance.

Drilling activities. Drilling involves numerous risks, including the risk that no commercially productive oil or gas reservoirs will be encountered. The cost of drilling, completing and operating wells is often uncertain and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions and shortages or delays in the delivery of equipment. The Company's future drilling activities may not be successful and, if unsuccessful, such failure could have an adverse effect on the Company's future results of operations and financial condition. While all drilling, whether developmental or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. Because of the percentage of the Company's capital budget devoted to higher risk exploratory projects, it is likely that the Company will continue to experience exploration and abandonment expense.

Unproved properties. At December 31, 2001 and 2000, the Company carried unproved property costs of $187.8 million and $229.2 million, respectively. United States generally accepted accounting principles require periodic evaluation of these costs on a project-by-project basis in comparison to their estimated value. These evaluations will be affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of the leases, contracts and permits appurtenant to such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, the Company will recognize noncash charges in the earnings of future periods. During 1999 the Company recognized an impairment provision of $17.9 million to reduce the carrying value of certain of its East Texas unproved gas properties (see Note L of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data").

Acquisitions. Acquisitions of producing oil and gas properties have been a key element of the Company's growth. The Company's growth following the full development of its existing property base could be impeded if it is unable to acquire additional oil and gas properties on a profitable basis. The success of any acquisition will depend on a number of factors, including the ability to estimate accurately the recoverable volumes of reserves, rates of future production and future net revenues attainable from the reserves and to assess possible environmental liabilities. All of these factors affect whether an acquisition will ultimately generate cash flows sufficient to provide a suitable return on investment. Even though the Company performs a review of the properties it seeks to acquire that it believes is consistent with industry practices, such reviews are often limited in scope.

Divestitures. The Company regularly reviews its property base for the purpose of identifying non-strategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. Various factors could materially affect the ability of the Company to dispose of non-strategic assets, including the availability of purchasers willing to purchase the non-strategic assets at prices acceptable to the Company.

Operation of natural gas processing plants. As of December 31, 2001, the Company owns interests in nine natural gas processing plants and four treating facilities. The Company operates six of the plants and all four treating facilities. There are significant risks associated with the operation of natural gas processing plants. Gas and NGLs are volatile and explosive and may include carcinogens. Damage to or misoperation of a natural gas processing plant or facility could result in an explosion or the discharge of toxic gases, which could result in significant damage claims in addition to interrupting a revenue source.

Operating hazards and uninsured losses. The Company's operations are subject to all the risks normally incident to the oil and gas exploration and production business, including blowouts, cratering, explosions and pollution and other environmental damage, any of which could result in substantial losses to the Company due to injury or loss of life, damage to or destruction of wells, production facilities or other property, clean-up responsibilities, regulatory investigations and penalties and suspension of operations. Although the Company currently maintains insurance coverage that it considers reasonable and that is similar to that maintained by comparable companies in the oil and gas industry, it is not fully insured against certain of these risks, either because such insurance is not available or because of high premium costs.

Environmental. The oil and gas business is subject to environmental hazards, such as oil spills, gas leaks and ruptures and discharges of toxic substances or gases that could expose the Company to substantial liability due to pollution and other environmental damage. A variety of federal, state and foreign laws and regulations govern the environmental aspects of the oil and gas business. Noncompliance with these laws and regulations may subject the Company to penalties, damages or other liabilities, and compliance may increase the cost of the Company's operations. Such laws and regulations may also affect the costs of acquisitions. See "Item 1. Business - Competition, Markets and Regulation - Environmental and health controls".

The Company does not believe that its environmental risks are materially different from those of comparable companies in the oil and gas industry. Nevertheless, no assurance can be given that future environmental laws will not result in a curtailment of production or processing or a material increase in the costs of production, development, exploration or processing or otherwise adversely affect the Company's operations and financial condition. Pollution and similar environmental risks generally are not fully insurable.

Debt restrictions and availability. The Company is a borrower under fixed term senior notes and a line of credit. The terms of the Company's borrowings under the senior notes and the line of credit specify scheduled debt repayments and require the Company to comply with certain associated covenants and restrictions. The Company's ability to comply with the debt repayment terms, associated covenants and restrictions is dependent on, among other things, factors outside the Company's direct control, such as commodity prices, interest rates and competition for available debt financing. See Note D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the Company's outstanding debt and the terms associated therewith.

Competition. The oil and gas industry is highly competitive. The Company competes with other companies, producers and operators for acquisitions and in the exploration, development, production and marketing of oil and gas. Some of these competitors have substantially greater financial and other resources than the Company. See "Item 1. Business - Competition, Markets and Regulation".

Government regulation. The Company's business is regulated by a variety of federal, state, local and foreign laws and regulations. There can be no assurance that present or future regulations will not adversely affect the Company's business and operations. See "Item 1. Business - Competition, Markets and Regulation".

International operations. At December 31, 2001, approximately 22 percent of the Company's proved reserves of oil, NGLs and gas were located outside the United States (17 percent in Argentina, four percent in Canada and one percent in South Africa). The success and profitability of international operations may be adversely affected by risks associated with international activities, including economic and labor conditions, political instability, tax laws (including host-country export, excise and income taxes and United States taxes on foreign subsidiaries) and changes in the value of the U.S. dollar versus the local currencies in which oil and gas producing activities may be denominated. To the extent that the Company is involved in international activities, changes in exchange rates can adversely affect the Company's future consolidated financial position, results of operations and liquidity. See Critical Accounting Policies included in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information specific to Argentina's economic and political situation.

Estimates of reserves and future net revenues. Numerous uncertainties exist in estimating quantities of proved reserves and future net revenues therefrom. The estimates of proved reserves and related future net revenues set forth in this Report are based on various assumptions, which may ultimately prove to be inaccurate. Therefore, such estimates should not be construed as accurate estimates of the current market value of the Company's proved reserves.

ITEM 2. PROPERTIES

The information included in this Report about the Company's oil, NGL and gas reserves as of December 31, 2001, 2000 and 1999, including Standardized Measure, is based on proved reserves as determined by the Company's engineers.

Numerous uncertainties exist in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the Company's control. This Report contains estimates of the Company's proved oil and gas reserves and the related future net revenues, which are based on various assumptions, including those prescribed by the SEC. Actual future production, oil and gas prices, revenues, taxes, capital expenditures, operating expenses, geologic success and quantities of recoverable oil and gas reserves may vary substantially from those assumed in the estimates and could materially affect the estimated quantities and related Standardized Measure of proved reserves set forth in this Report. In addition, the Company's reserves may be subject to downward or upward revisions based on production performance, purchases or sales of properties, results of future development, prevailing oil and gas prices and other factors. Therefore, estimates of the Standardized Measure of proved reserves should not be construed as accurate estimates of the current market value of the Company's proved reserves.

Standardized Measure is a reporting convention that provides a common basis for comparing oil and gas companies subject to the rules and regulations of the SEC. It requires the use of oil and gas spot prices prevailing as of the date of computation. Consequently, it may not reflect the prices ordinarily received or that will be received for oil and gas because of seasonal price fluctuations or other varying market conditions. Standardized Measures as of any date are not necessarily indicative of future results of operations. Accordingly, estimates included herein of future net revenues may be materially different from the net revenues that are ultimately received.

The Company did not provide estimates of total proved oil and gas reserves during 2001, 2000 or 1999 to any federal authority or agency, other than the SEC.

Proved Reserves

The Company's proved reserves totaled 671.4 million BOE at December 31, 2001, 628.2 million BOE at December 31, 2000 and 605.5 million BOE at December 31, 1999, representing $2.5 billion, $5.6 billion and $2.9 billion, respectively, of Standardized Measure. The seven percent increase in proved reserve volumes during 2001 was primarily attributable to the Company's successful capital investments, while the 56 percent decrease in Standardized Measure during 2001 was primarily due to decreases in commodity prices. The four percent increase in proved reserve volumes in 2000 was primarily attributable to the Company's successful capital investments, while the 93 percent increase in Standardized Measure during 2000 was primarily due to increases in commodity prices.

On a BOE basis, 70 percent of the Company's total proved reserves at December 31, 2001 are proved developed reserves. Based on reserve information as of December 31, 2001, and using the Company's reserve report production information for 2002, the reserve-to-production ratio associated with the Company's proved reserves is 14 years on a BOE basis. The following table provides information regarding the Company's proved reserves and average daily production by geographic area as of and for the year ended December 31, 2001.

PROVED OIL AND GAS RESERVES AND AVERAGE DAILY PRODUCTION

	Proved Reserves as of December 31, 2001				2001 Average Daily Production (a)		
	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE	Standardized Measure (000)	Oil & NGLs (Bbls)	Gas (Mcf)	BOE
United States	279,146	1,474,090	524,829	$ 1,965,129	43,456	212,629	78,894
Argentina	35,669	471,150	114,193	391,151	10,316	87,204	24,850
Canada	2,659	132,061	24,669	129,585	1,839	50,481	10,253
South Africa	7,685	-	7,685	14,461	-	-	-
Total	325,159	2,077,301	671,376	$ 2,500,326	55,611	350,314	113,997

(a) The 2001 average daily production is calculated using a 365-day year and without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred during the year.

Alternate Reserve Case

In addition to the proved reserve table above, the Company calculated an alternative reserve case, as presented below, utilizing an assumed WTI Cushing, Oklahoma spot oil price of $22.00 per Bbl and an assumed Henry Hub, Louisiana spot gas price of $3.50 per Mcf as compared to the year-end proved reserve calculation which used a WTI Cushing, Oklahoma spot oil price of $19.76 per Bbl and a Henry Hub, Louisiana spot gas price of $2.73 per Mcf. The alternative reserve case has all of the same assumptions as the proved reserve case at year end, other than pricing.

	Alternative Reserve Case as of December 31, 2001			
	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE	Alternate Standardized Measure (000)
United States	287,500	1,499,328	537,388	$ 2,616,332
Argentina	35,669	471,150	114,194	433,478
Canada	2,625	128,592	24,057	182,116
South Africa	7,685	-	7,685	28,589
Total	333,479	2,099,070	683,324	$ 3,260,515

The alternative reserve case represents the minimum pricing assumptions that the Company used to make investment decisions during 2001. Such investment decisions required, among other items, a discounted return on investment greater than 150 percent prior to approval.

In addition to the alternate reserve case above, the Company estimates that the potential incremental value from other exploration and extension opportunities on the Canyon Express, Devils Tower and Falcon deepwater Gulf of Mexico discoveries and Sable discovery in South Africa to be as much as $285 million using the same alternate reserve case assumptions. The Company also calculated an alternate discount rate for the Company's long-lived Spraberry, Hugoton and West Panhandle fields. The Company estimates that the incremental value of these long-lived reserves using an eight percent discount rate versus a ten percent discount rate under the same alternate reserve case parameters is approximately $165 million.

No assurance can be given that future commodity prices will be similar to the prices utilized in the alternate reserve case since commodity prices have historically been very volatile. Furthermore, oil and gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. In addition, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of undrilled prospects and new discoveries are significantly more imprecise than those of currently producing oil and gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The Company's stockholders and other users of this information should not assume that the Alternate Standardized Measure is the current market value of the Company's estimated reserves. The Company calculated the Alternate Standardized Measure based on estimated reserves calculated using the price and cost assumptions referred to above. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Additionally, the Alternate Standardized Measure does not include estimates of the Company's future administrative expense or borrowing costs, the incurrence of which are ordinary expenditures for the conduct of business.

Finding Cost and Reserve Replacement

The Company's acquisition and finding costs per BOE for 2001, 2000 and 1999 were $7.49, $4.66 and $2.21 per BOE, respectively. The average acquisition and finding cost for the three-year period from 1999 to 2001 was $4.74 per BOE, representing a 32 percent decrease over the 2000 three-year average rate of $6.94 per BOE.

During 2001, the Company replaced 208 percent of its annual production on a BOE basis (169 percent for oil and NGLs and 245 percent for gas). During 2000, the Company replaced 167 percent of its annual production on a BOE basis (196 percent for oil and NGLs and 140 percent for gas). During 1999, the Company replaced 178 percent of its annual production on a BOE basis (262 percent for oil and NGLs and 99 percent for gas). The Company's 2001 reserve replacement percentage was primarily impacted by asset purchases and new discoveries and field extensions while the 2000 and 1999 reserve replacement percentages were primarily impacted by changes in commodity prices.

Description of Properties

As of December 31, 2001, the Company has production, development and exploration operations in the United States, Argentina, Canada and South Africa, and exploration opportunities in Gabon and Tunisia.

Domestic. The Company's domestic operations are located in the Permian Basin, Mid Continent, Gulf of Mexico and onshore Gulf Coast areas of the United States. Approximately 81 percent of the Company's domestic proved reserves are located in the Spraberry, Hugoton and West Panhandle fields. The mature Spraberry, Hugoton and West Panhandle fields generate substantial operating cash flow and have a portfolio of low risk infill drilling opportunities. The cash flows generated from these fields provide funding for the Company's other development and exploration activities both domestically and internationally. During 2001, the Company expended $334.2 million in domestic acquisition, exploration and development drilling activities. The Company has budgeted approximately $260 million for domestic acquisition, exploration and development drilling expenditures for 2002.

Spraberry field. The Spraberry field was discovered in 1949 and encompasses eight counties in West Texas. The field is approximately 150 miles long and 75 miles wide at its widest point. The oil produced is West Texas Intermediate Sweet, and the gas produced is casinghead gas with an average energy content of 1,400 Btu per Mcf. The oil and gas are produced from three formations, the upper and lower Spraberry and the Dean, at depths ranging from 6,700 feet to 9,200 feet. The center of the Spraberry field was unitized in the late 1950's and early 1960's by the major oil companies; however, until the late 1980's there was very limited development activity in the field. Since 1989, the Company has focused its development drilling activities in the unitized portion of the Spraberry field due to the dormant condition of the properties. The Company believes the area offers excellent opportunities to enhance oil and gas reserves because of the hundreds of undeveloped infill drilling locations, all of which are reflected in the Company's proved undeveloped reserves, and the ability to reduce operating expenses through economies of scale.

During 2001, the Company placed 131 Spraberry wells on production, drilled one developmental dry hole and, at December 31, 2001, had 17 wells in progress. The Company is continuing to evaluate its 2002 Spraberry drilling program and has postponed the program until drilling costs align more favorably with commodity prices.

Hugoton field. The Hugoton field in southwest Kansas is one of the largest producing gas fields in the continental United States. The gas is produced from the Chase and Council Grove formations at depths ranging from 2,700 feet to 3,000 feet. The Company's Hugoton properties represent approximately 13 percent of the proved reserves in the field and are located on approximately 257,000 gross acres (237,000 net acres), covering approximately 400 square miles. The Company has working interests in approximately 1,200 wells in the Hugoton field, about 1,000 of which it operates, and partial royalty interests in approximately 500 wells. The Company owns substantially all of the gathering and processing facilities, primarily the Satanta plant, that service its production from the Hugoton field. Such ownership allows the Company to control the production, gathering, processing and sale of its gas and associated NGLs.

Production in the Hugoton field is subject to allowables set by state regulators, but the Company's Hugoton operated wells are capable of producing approximately 106 MMcf of wet gas per day (i.e., gas production at the wellhead before processing and before reduction for royalties). The Company estimates that it and other major producers in the Hugoton field produced at or near capacity in 2001. During 2001, the Company completed 12 development wells in the Hugoton field. The Company does not plan to drill any Hugoton development wells in 2002 given the recent downturn in gas prices.

The Company is evaluating the feasibility of infill drilling into the Council Grove Formation and may submit an application to the Kansas Corporation Commission to allow infill drilling. Such infill drilling may increase production from the Company's Hugoton properties. However, until an application has been approved, the Company will not reflect any of the infill drilling locations as proved undeveloped reserves. There can be no assurance that the application will be filed or approved, or as to the timing of such approval if granted.

West Panhandle field. The West Panhandle properties are located in the panhandle region of Texas where initial production commenced in 1918. These stable, long-lived reserves are attributable to the Red Cave, Brown Dolomite, Granite Wash and fractured Granite formations at depths no greater than 3,500 feet. The Company's gas in the West Panhandle field has an average energy content of 1,300 Btu per Mcf and is produced from approximately 600 wells on more than 241,000 gross (185,000 net) acres covering over 375 square miles. The Company's wellhead gas produced from the West Panhandle field contains a high quantity of NGLs, yielding relatively greater NGL volumes than realized from the Company's 1,025 Btu per Mcf content wellhead gas in its Hugoton field. The Company operates the wells, production equipment and, since May 2001, the Colorado Interstate Gas Company - (a subsidiary of El Paso Energy Corp.) owned gathering system. Production from the West Panhandle field is processed through the Company-owned and operated Fain natural gas processing plant.

During 2001, the Company placed 29 new wells on production and had one additional well in progress at December 31, 2001. The Company is evaluating its plans for 2002 given the recent declines in oil and gas prices and has not determined how many, if any, wells will be drilled in the West Panhandle field during 2002.

Gulf of Mexico area. In the Gulf of Mexico, the Company is focused on reserve and production growth through a portfolio of shelf and deepwater development projects, high-impact, higher-risk deepwater exploration drilling, shelf exploration drilling and exploitation opportunities inherent in the properties the Company currently has producing on the shelf. To accomplish this, the Company has devoted most of its domestic exploration efforts to these two areas, as well as its investment in and utilization of 3-D seismic technology. During 2001, the Company successfully drilled one development and four exploratory wells in the deepwater Gulf of Mexico and four development and four exploration wells on the shelf. The Company also drilled two exploratory dry holes in the deepwater Gulf of Mexico and three exploratory dry holes on the shelf during 2001 and had one shelf and two deepwater development wells and one shelf and one deepwater exploration well in progress as of December 31, 2001.

In the deepwater Gulf of Mexico, the Company has sanctioned three major development projects that are in progress at December 31, 2001:

- Canyon Express - The TotalFinaElf-operated Aconcagua and the Marathon-operated Camden Hills discoveries in Mississippi Canyon are being jointly developed as part of the Canyon Express gas project. Facilities construction and well completions are underway and installation is in-progress for the TotalFinaElf-operated Canyon Express subsea gathering system with production scheduled to begin during July 2002. Wells will be brought on sequentially and are expected to achieve a peak rate of approximately 110 MMcf of gas per day and 180 Bbls of condensate per day net to the Company. During the fourth quarter of 2001, the Company acquired an incremental 12.5 percent interest in the Aconcagua field and a 5.5 percent interest in the Canyon Express subsea gathering system for $25.5 million. The Company's ownership positions in this project are now comprised of a 23.5 percent equity interest in the Canyon Express subsea gathering system, a 37.5 percent working interest in Aconcagua and a 33 percent working interest in Camden Hills.

- Devils Tower - At the Dominion-operated Devils Tower development project in Mississippi Canyon, the Company successfully drilled two wells to explore for new reserves in previously undrilled reservoirs and to further extend the previously tested zones. During 2001, the project was sanctioned as a spar development project with the owners leasing a spar from a third party for the life of the field. Construction of the spar is underway, two development wells and one extension well were in progress as of December 31, 2001, and production is anticipated to begin during the second quarter of 2003. One additional development well will be drilled during 2002. The wells will be brought on sequentially with peak production expected to reach 8,000 to 10,000 BOEs per day net to the Company's 25 percent working interest.

- Falcon - The Mariner-operated Falcon project, which was recently sanctioned, was successfully drilled and sidetracked during 2001. The Company owns a 45 percent working interest in this discovery and was the successful bidder on 21 deepwater Gulf of Mexico blocks, 12 of which are near the Falcon discovery that the Company shares with its partner, Mariner. Two additional development wells are planned for Falcon during 2002. Initial production from Falcon is anticipated during the first quarter of 2003 at expected rates of 79 MMcf of gas per day and 220 Bbls of condensate per day net to the Company's interest.

In addition to the development projects described above in the deepwater Gulf of Mexico, the Company drilled the Dominion-operated Turnberry prospect during 2001. The well encountered hydrocarbon bearing sands; however, sidetrack operations on the Turnberry discovery were unsuccessful and evaluations of the initial wellbore using a 3-D seismic survey are in progress to determine if the discovery has commercial quantities of hydrocarbons. If commercial quantities of hydrocarbons cannot be confirmed during the first quarter of 2002, the Company will recognize a $9.3 million charge to exploration and abandonments for the costs of the initial exploratory well. The Company also drilled its Argo prospect during 2001 which was unsuccessful.

During the fourth quarter of 2001, the Company participated in the drilling of the Marathon-operated Ozona Deep prospect that was successfully drilled. The well encountered approximately 345 feet of net oil pay in two intervals and one or two appraisal wells are planned for Ozona Deep in the first half of 2002. In addition to the development projects discussed above and Ozona Deep, the Company plans to drill one or two additional exploratory wells in the deepwater Gulf of Mexico during 2002.

On the Gulf of Mexico shelf, the Company participated in drilling five prospects during 2001 in addition to initiating an extensive production optimization program at the Company's Inland Bay fields in south Louisiana. First, the Texaco-operated Cyrus prospect was sanctioned during 2001 and development plans are underway with production expected to commence during the fourth quarter of 2002 at expected initial rates of 2.3 MMcf of gas per day and 360 Bbls of condensate per day net to the Company's 5.7 percent working interest. Second, the Aviara-operated Oneida prospect was successfully drilled and is currently being completed. Initial production is anticipated during the second quarter of 2002 at expected rates of 1.1 MMcf of gas per day and 30 Bbls of condensate per day net to the Company's 13.7 percent working interest. Third, the Company participated in the Spinnaker-operated Stirrup prospect during 2001, in which the Company owns a 25 percent working interest. An initial discovery well was drilled and tested at gross rates over 21 MMcf of gas per day and 130 Bbls of condensate per day. A second and third well were successfully drilled and platform construction, as well as completion operations, have commenced. The Company anticipates first production in April 2002 at expected initial rates of 2.7 MMcf of gas per day and 20 Bbls of condensate per day net to the Company's interest. Finally, the Company drilled its Cruiser and Malta prospects during 2001 that were plugged and abandoned since commercial quantities of hydrocarbons were not present.

The Company has also initiated an effort to reevaluate all of its current producing properties on the shelf to determine if there are additional recompletion opportunities or development or exploration drilling opportunities on those properties. The Company drilled an exploratory dry hole in one of its Inland Bay fields and has initiated workover and recompletion programs in these fields. The Company has been applying new technology to the fields in an attempt to identify untapped potential in the multiple pay zones of these fields that may have been missed over the years. Results in the program have been encouraging with a production increase of approximately 1,500 BOE per day having been achieved during 2001. The program will be continued during 2002, but to a lesser extent, given lower commodity prices. In addition to this project, the Company plans to drill a limited number of exploratory prospects on the shelf during 2002.

Onshore Gulf Coast area. The Company has focused its drilling efforts in this area on the Pawnee field in the Edwards Reef trend in South Texas. The Company drilled eight development wells at Pawnee during 2001 and plans to drill three more in the first quarter of 2002. Since the Company began this successful program, net production has more than tripled, increasing from 11 MMcf per day at the end of 1999 to 37 MMcf per day at the end of 2001. The Company is also continuing its development drilling in East Texas and is drilling an exploration well in North Louisiana. Activities in these areas will be scaled back during 2002 given the lower commodity price environment.

International. The Company's international operations are located in the Neuquen and Austral Basins areas of Argentina and the Chinchaga, Martin Creek and Lookout Butte areas of Canada. Additionally, the Company's fourth significant development project, the Sable oil field located in shallow water offshore South Africa, is scheduled for first production in early 2003. The Company has also entered into agreements to explore for oil and gas reserves in South Africa, Gabon and Tunisia. As of December 31, 2001, approximately 17 percent, four percent and one percent of the Company's proved reserves are located in Argentina, Canada and South Africa, respectively.

Argentina. The Company's share of Argentine production during 2001 averaged 24.9 MBOE per day, or approximately 22 percent of the Company's equivalent production. The Company's operated production in Argentina is concentrated in the Neuquen Basin which is located about 925 miles southwest of Buenos Aires and just to the east of the Andes Mountains. Oil and gas are produced primarily from the Loma Negra/NI Block, the Neuquen del Medio Block, the Al Sur de la Dorsal Block and the Estacion Fernandez Oro Block, in each of which the Company has a 100 percent working interest. During 2001, the Company acquired a 100 percent working interest in the Anticlinal Campamento producing field as well as two exploration blocks, Cerro Vagon and Dos Hermanas. The Company also increased its interest in the La Calera and Bajo Baguales exploration blocks during 2001.

The production concession in the Austral Basin is located in Tierra del Fuego, which is an island in the extreme southern portion of Argentina, approximately 1,500 miles south of Buenos Aires. Oil, gas and NGLs are produced from six separate fields in which the Company has a 35 percent working interest. Currently, production is being sent to the mainland through oil tankers and gas pipelines and exported to Chile through pipelines. Also in the Austral Basin is the Company-operated Lago Fuego Block, which started operations during 2001. Production from this block is mainly gas and NGLs which are sold to the city of Ushuaia and other local markets. The Company holds a 50 percent working interest in the Lago Fuego Block.

During 2001, the Company expended $98.1 million on Argentine acquisition, exploration and development activities and drilled 20 development wells and 42 extension/exploratory wells in Argentina, of which 19 development wells and 26 extension/exploratory wells were successful. The Company plans to spend approximately $15 million in Argentina during 2002 to principally complete construction of its Loma Negra gas plant. Other significant capital projects have been suspended at this time due to the economic instability in Argentina and the resulting devaluation of the Argentine peso.

Canada. The Company's Canadian producing properties are located primarily in Alberta and British Columbia, Canada. Production during 2001 averaged 10.3 MBOE per day, or approximately nine percent of the Company's equivalent production. The Company continues to focus its development, exploration and acquisition activities in the core areas of northeast British Columbia and southwest Alberta. The Canadian assets are geographically concentrated, predominantly shallow gas and more than 95 percent operated by the Company in the following areas: Chinchaga, Martin Creek and Lookout Butte.

Production from the Chinchaga area in northeast British Columbia is relatively dry gas from formation depths averaging 3,400 feet. In the Martin Creek area of British Columbia, production is relatively dry gas from various reservoirs ranging from 3,700 feet to 4,300 feet. The Lookout Butte area in southwest Alberta produces gas and condensate from the Mississippian Turner Valley formation at approximately 12,000 feet. The Company sold its interest in the Rycroft/Spirit River area waterflood in northwest Alberta in December 2001 for approximately $12.0 million.

During 2001, the Company expended $37.5 million on Canadian exploration and development activities and drilled 26 development wells and 25 exploratory wells primarily in the Chinchaga and Martin Creek areas, of which 24 development wells and 12 exploratory wells were successful. Most of these wells were drilled during the first quarter as these areas are only accessible for drilling during the winter months. The Company, as operator, plans to drill approximately 19 wells and expand facility and compressor capacity to 50 MMcf of gas per day at the Company-owned Chinchaga plant during 2002. The Company expects to participate in an additional four wells operated by another company in the same area. The Company plans to spend approximately $25 million on oil and gas development and exploration opportunities in Canada during 2002.

Africa. In Africa, the Company has entered into agreements to explore for oil and gas in South Africa, Gabon and Tunisia. The South African agreements cover over 13 million acres along the southern coast of South Africa, generally in water depths less than 650 feet. The Gabon agreement covers over 314,000 acres off the coast of Gabon, generally in water depths less than 100 feet. The Tunisian agreements can be separated into two categories. The first includes three permits covering 2.7 million acres onshore southern Tunisia which the Company operates with a 50 percent working interest. The second includes the Anadarko-operated Anaguid permit covering 1.1 million acres onshore southern Tunisia in which the Company has a 30 percent working interest. During 2001, the Company expended $59.9 million of acquisition, development and exploration drilling and seismic capital in South Africa, Gabon and Tunisia. The Company drilled four exploratory wells in South Africa during 2001, of which two were successful. In addition, a successful exploratory well was drilled off the coast of Gabon and a dry hole was drilled in Tunisia.

South Africa. In South Africa, the Company spent $39.3 million of drilling and seismic capital to drill two wells on its Company-operated Boomslang prospect, in which the Company has a 49 percent working interest, drill a gas appraisal well on the Soekor-operated E-BB tract, in which the Company has a 40 percent working interest, and acquire two 3-D seismic surveys. The initial Boomslang well was successful while the appraisal well was unsuccessful. One of the two seismic surveys was acquired over the Boomslang trend area where several other prospects have been identified. The Company will continue to evaluate the commercial feasibility of the Boomslang prospect using this new 3-D data. In addition, the Company drilled and tested the E-BB2 gas well in the center of the Bredasdorp Basin. Results of this well and other wells drilled in this trend are being assessed as part of a larger gas development project that is currently being evaluated. The Company also acquired a 3-D seismic survey in the Port Elizabeth Trough Area of Block 14 during 2001. During 2002, the seismic data acquired in 2001 will be analyzed and the results from the aforementioned exploration activities will continue to be evaluated. The Company currently plans to drill two exploration wells during 2002.

During 2002, the Company plans to complete its Sable development project in South Africa with production anticipated to begin in early 2003. Development drilling is underway, floating production facility upgrades are in progress and subsea trees are being manufactured. Production for the first year is expected to average approximately 11,600 Bbls of oil per day net to the Company's 40 percent working interest.

Gabon. In Gabon, the Company spent $11.4 million of drilling and seismic capital to drill and test the initial exploratory well on its Bigorneau South prospect, located offshore in the Southern Gabon Basin on its Olowi permit. Pioneer is the operator of the permit with a 100 percent working interest. The Company has entered its application to enter the Second Exploration Period on the Olowi Permit, which requires two additional exploratory wells to be drilled over a two-year period. Seismic evaluations continue on this discovery and the Company plans to drill two exploration wells and one appraisal well during 2002.

Tunisia. Plans for Tunisia in 2002 include a 3-D seismic survey to be shot over the three operated permits as well as a seismic survey in the Anadarko-operated Anaguid permit. Based on the results and interpretation of such seismic surveys, the Company expects to drill two to three wells in Tunisia during 2002.

Selected Oil and Gas Information

The following tables set forth selected oil and gas information for the Company as of and for each of the years ended December 31, 2001, 2000 and 1999. Because of normal production declines, increased or decreased drilling activities and the effects of past and future acquisitions or divestitures, the historical information presented below should not be interpreted as indicative of future results.

Production, price and cost data. The following table sets forth production, price and cost data with respect to the Company's properties for the years ended December 31, 2001, 2000 and 1999.

PRODUCTION, PRICE AND COST DATA (a)

	Year Ended December 31,											
	2001				2000				1999			
	United States	Argentina	Canada	Total	United States	Argentina	Canada	Total	United States	Argentina	Canada	Total
Production information:												
Annual production:												
Oil (MBbls)	8,629	3,566	303	12,498	8,989	3,238	308	12,535	11,448	2,352	1,654	15,454
NGLs (MBbls) ..	7,232	200	368	7,800	7,883	193	303	8,379	8,714	217	306	9,237
Gas (MMcf)	77,609	31,830	18,426	127,865	83,930	35,695	16,219	135,844	106,094	34,477	17,886	158,457
Total (MBOE) ..	28,796	9,071	3,742	41,609	30,861	9,380	3,314	43,555	37,845	8,315	4,941	51,101
Average daily production:												
Oil (Bbls)	23,641	9,769	831	34,241	24,561	8,847	841	34,249	31,366	6,443	4,530	42,339
NGLs (Bbls) ...	19,815	547	1,008	21,370	21,538	527	829	22,894	23,875	594	839	25,308
Gas (Mcf)	212,629	87,204	50,481	350,314	229,316	97,526	44,315	371,157	290,670	94,457	49,003	434,130
Total (BOE)	78,894	24,851	10,253	113,997	84,318	25,628	9,056	119,002	103,686	22,780	13,536	140,002
Average prices, including hedge results:												
Oil (per Bbl) ...	$ 24.34	$ 23.79	$ 21.87	$ 24.12	$ 22.07	$29.09	$ 27.50	$ 24.01	$ 15.03	$18.41	$ 13.28	$ 15.36
NGLs (per Bbl) .	$ 16.88	$ 19.29	$ 21.11	$ 17.14	$ 20.05	$22.91	$ 24.32	$ 20.27	$ 11.61	$11.30	$ 12.62	$ 11.64
Gas (per Mcf) ..	$ 4.10	$ 1.31	$ 2.86	$ 3.23	$ 3.50	$ 1.19	$ 2.88	$ 2.81	$ 2.17	$ 1.10	$ 1.82	$ 1.90
Revenue (per BOE)	$ 22.56	$ 14.36	$ 17.94	$ 20.36	$ 21.04	$15.03	$ 18.85	$ 19.58	$ 13.28	$10.07	$ 11.81	$ 12.62
Average prices, excluding hedge results:												
Oil (per Bbl) ...	$ 24.56	$ 22.40	$ 21.87	$ 23.88	$ 28.76	$29.09	$ 27.50	$ 28.81	$ 16.20	$18.41	$ 13.28	$ 16.23
NGLs (per Bbl) .	$ 16.88	$ 19.29	$ 21.11	$ 17.14	$ 20.05	$22.91	$ 24.32	$ 20.27	$ 11.61	$11.30	$ 12.62	$ 11.64
Gas (per Mcf) ..	$ 3.96	$ 1.31	$ 3.27	$ 3.20	$ 3.73	$ 1.19	$ 3.45	$ 3.03	$ 2.07	$ 1.10	$ 1.84	$ 1.84
Revenue (per BOE)	$ 22.26	$ 13.81	$ 19.95	$ 20.21	$ 23.63	$15.03	$ 21.65	$ 21.63	$ 13.37	$10.07	$ 11.90	$ 12.69
Average costs:												
Production costs (per BOE):												
Lease operating .	$ 2.76	$ 2.64	$ 3.01	$ 2.76	$ 2.45	$ 2.30	$ 2.53	$ 2.42	$ 2.02	$ 2.04	$ 3.02	$ 2.11
Taxes:												
Production. ...	.98	.28	-	.74	.99	.30	-	.77	.49	.16	-	.39
Ad valorem ...	.71	-	-	.49	.41	-	-	.29	.41	-	-	.31
Field fuel	1.27	-	-	.88	1.01	-	-	.71	.28	-	-	.21
Workover	.20	.01	.32	.17	.17	-	.42	.15	.09	-	.34	.10
Total	$ 5.92	$ 2.93	$ 3.33	$ 5.04	$ 5.03	$ 2.60	$ 2.95	$ 4.34	$ 3.29	$ 2.20	$ 3.36	$ 3.12
Depletion expense (per BOE)	$ 4.46	$ 5.67	$ 7.71	$ 5.02	$ 3.95	$ 5.56	$ 7.58	$ 4.57	$ 4.06	$ 4.68	$ 5.18	$ 4.27

(a) These amounts represent the Company's historical results from operations without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred during the respective years.

Productive wells. The following table sets forth the number of productive oil and gas wells attributable to the Company's properties as of December 31, 2001, 2000 and 1999.

PRODUCTIVE WELLS (a)

	Gross Productive Wells			Net Productive Wells		
	Oil	Gas	Total	Oil	Gas	Total
As of December 31, 2001:						
United States	3,485	1,931	5,416	2,116	1,613	3,729
Argentina	669	162	831	454	132	586
Canada	4	299	303	3	240	243
Total	4,158	2,392	6,550	2,573	1,985	4,558
As of December 31, 2000:						
United States	3,577	1,847	5,424	2,166	1,550	3,716
Argentina	575	211	786	434	154	588
Canada	95	234	329	45	175	220
Total	4,247	2,292	6,539	2,645	1,879	4,524
As of December 31, 1999:						
United States	3,835	2,244	6,079	2,558	1,736	4,294
Argentina	514	199	713	376	142	518
Canada	157	196	353	66	135	201
Total	4,506	2,639	7,145	3,000	2,013	5,013

(a) Productive wells consist of producing wells and wells capable of production, including shut-in wells. One or more completions in the same well bore are counted as one well. Any well in which one of the multiple completions is an oil completion is classified as an oil well. As of December 31, 2001, the Company owned interests in 76 gross wells containing multiple completions.

Leasehold acreage. The following table sets forth information about the Company's developed, undeveloped and royalty leasehold acreage as of December 31, 2001.

LEASEHOLD ACREAGE

	Developed Acreage		Undeveloped Acreage		Royalty
	Gross Acres	Net Acres	Gross Acres	Net Acres	Acreage
As of December 31, 2001:					
United States	914,114	720,189	818,715	655,332	219,130
Argentina	674,000	278,000	1,154,000	991,000	-
Canada	153,000	110,000	350,000	252,000	-
South Africa	9,600	3,840	13,625,400	12,266,160	-
Gabon	-	-	313,937	313,937	-
Tunisia	-	-	4,083,072	1,806,013	-
Total	1,750,714	1,112,029	20,345,124	16,284,442	219,130

Drilling activities. The following table sets forth the number of gross and net productive and dry wells in which the Company had an interest that were drilled during the years ended December 31, 2001, 2000 and 1999. This information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and the oil and gas reserves generated thereby or the costs to the Company of productive wells compared to the costs of dry wells.

DRILLING ACTIVITIES

	Gross Wells Year Ended December 31,			Net Wells Year Ended December 31,		
	2001	2000	1999	2001	2000	1999
United States:						
Productive wells:						
Development	228	159	199	114.6	91.3	131.3
Exploratory	20	11	7	11.0	4.7	4.6
Dry holes:						
Development	15	3	1	14.6	1.9	.8
Exploratory	8	3	7	5.1	1.6	2.7
	271	176	214	145.3	99.5	139.4
Argentina:						
Productive wells:						
Development	19	28	19	17.7	26.7	16.6
Exploratory	26	38	25	25.5	37.6	24.1
Dry holes:						
Development	1	2	3	1.0	2.0	3.0
Exploratory	16	16	8	14.0	14.5	6.5
	62	84	55	58.2	80.8	50.2
Canada:						
Productive wells:						
Development	24	17	34	20.3	17.9	18.8
Exploratory	12	12	-	10.2	9.9	-
Dry holes:						
Development	2	4	-	2.0	2.5	-
Exploratory	13	2	1	11.8	1.9	.3
	51	35	35	44.3	32.2	19.1
Other foreign:						
Productive wells:						
Development	-	-	-	-	-	-
Exploratory	3	-	-	2.4	-	-
Dry holes:						
Development	-	-	-	-	-	-
Exploratory	3	1	-	1.9	1.0	-
	6	1	-	4.3	1.0	-
Total	390	296	304	252.1	213.5	208.7
Success ratio (a)	85%	90%	93%	80%	88%	94%

(a) Represents those wells that were successfully completed as producing wells or wells capable of producing.

The following table sets forth information about the Company's wells that were in progress at December 31, 2001.

	Gross Wells	Net Wells
United States:		
Development	21	1.6
Exploratory	3	1.2
	24	2.8
Argentina:		
Development	1	1.0
Exploratory	3	3.0
	4	4.0
Canada:		
Development	5	5.0
Exploratory	1	1.0
	6	6.0
Total	34	12.8

ITEM 3. LEGAL PROCEEDINGS

The Company is party to various legal proceedings, which are described under "Legal actions" in Note G of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data". The Company is also party to other litigation incidental to its business. The claims for damages from such other legal actions are not in excess of 10 percent of the Company's current assets and the Company believes none of these actions to be material.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

The Company did not submit any matters to a vote of security holders during the fourth quarter of 2001.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON STOCK AND RELATED STOCKHOLDER MATTERS

The Company's common stock is listed and traded on the New York Stock Exchange and the Toronto Stock Exchange under the symbol "PXD". The following table sets forth, for the periods indicated, the high and low sales prices for the Company's common stock, as reported in the New York Stock Exchange composite transactions. The Company's $575 million credit agreement restricts the Company from paying or declaring dividends on common stock and certain other payments in excess of an aggregate $50 million annually. The Company's Board of Directors did not declare dividends to the holders of the Company's common stock during 2001 or 2000.

	High	Low
2001		
Fourth quarter	$ 19.70	$ 13.22
Third quarter	$ 19.38	$ 12.62
Second quarter	$ 23.05	$ 14.30
First quarter	$ 20.24	$ 15.45
2000		
Fourth quarter	$ 20.63	$ 12.44
Third quarter	$ 16.06	$ 10.63
Second quarter	$ 15.63	$ 9.00
First quarter	$ 10.75	$ 6.75

On February 25, 2002, the last reported sales price of the Company's common stock, as reported in the New York Stock Exchange composite transactions, was $19.49 per share.

As of February 25, 2002, the Company's common stock was held by approximately 38,866 holders of record.

ITEM 6. SELECTED FINANCIAL DATA

The following selected consolidated financial data for the Company should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data".

	Year Ended December 31,				
	2001	2000	1999	1998	1997 (a)
	(in millions, except per share data)				
Statement of Operations Data:					
Revenues:					
Oil and gas	$ 847.0	$ 852.7	$ 644.6	$ 711.5	$ 536.8
Interest and other (b)	21.8	25.8	89.7	10.4	4.3
Gain (loss) on disposition of assets, net	7.7	34.2	(24.2)	(.4)	4.9
	876.5	912.7	710.1	721.5	546.0
Costs and expenses:					
Oil and gas production	209.7	189.3	159.5	223.5	144.2
Depletion, depreciation and amortization	222.6	214.9	236.1	337.3	212.4
Impairment of properties and facilities	-	-	17.9	459.5	1,356.4
Exploration and abandonments	127.9	87.5	66.0	121.9	77.2
General and administrative	37.0	33.3	40.2	82.6	48.8
Reorganization	-	-	8.5	33.2	-
Interest	131.9	162.0	170.3	164.3	77.5
Other (c)	39.6	67.2	34.7	30.0	7.1
	768.7	754.2	733.2	1,452.3	1,923.6
Income (loss) before income taxes and extraordinary items	107.8	158.5	(23.1)	(730.8)	(1,377.6)
Income tax benefit (provision)	(4.0)	6.0	.6	(15.6)	500.3
Income (loss) before extraordinary items	103.8	164.5	(22.5)	(746.4)	(877.3)
Extraordinary items	(3.8)	(12.3)	-	-	(13.4)
Net income (loss)	$ 100.0	$ 152.2	$ (22.5)	$ (746.4)	$ (890.7)
Income (loss) before extraordinary items per share:					
Basic	$ 1.05	$ 1.65	$ (.22)	$ (7.46)	$ (16.88)
Diluted	$ 1.04	$ 1.65	$ (.22)	$ (7.46)	$ (16.88)
Net income (loss) per share:					
Basic	$ 1.01	$ 1.53	$ (.22)	$ (7.46)	$ (17.14)
Diluted	$ 1.00	$ 1.53	$ (.22)	$ (7.46)	$ (17.14)
Dividends per share	$ -	$ -	$ -	$ .10	$ .10
Weighted average shares outstanding:					
Basic	98.5	99.4	100.3	100.1	52.0
Diluted	99.7	99.8	100.3	100.1	52.0
Statement of Cash Flows Data:					
Cash flows from operating activities	$ 475.6	$ 430.1	$ 255.2	$ 314.1	$ 228.2
Cash flows from investing activities	$ (422.7)	$ (194.5)	$ 199.0	$ (517.0)	$ (341.2)
Cash flows from financing activities	$ (64.0)	$ (244.1)	$ (479.1)	$ 190.9	$ 166.0
Balance Sheet Data (as of December 31):					
Working capital (deficit) (d)	$ 27.4	$ (25.1)	$ (13.7)	$ (324.8)	$ 46.6
Property, plant and equipment, net	$ 2,784.3	$ 2,515.0	$ 2,503.0	$ 3,034.1	$ 3,515.8
Total assets	$ 3,271.1	$ 2,954.4	$ 2,929.5	$ 3,481.3	$ 4,153.0
Long-term obligations	$ 1,743.7	$ 1,804.5	$ 1,914.5	$ 2,101.2	$ 2,124.0
Total stockholders' equity	$ 1,285.4	$ 904.9	$ 774.6	$ 789.1	$ 1,548.8

(a) Includes amounts relating to the acquisition of Mesa Inc. and Chauvco Resources Ltd. in August and December 1997, respectively.

(b) 1999 includes $41.8 million of option fees and liquidated damages and $30.2 million of income associated with an excise tax refund.

(c) Other expense for 2001 includes $11.5 million, $9.9 million and $7.7 million of charges for changes in the fair values of derivatives excluded from hedge accounting treatment; Canadian gas marketing losses; and the remeasurement of Argentine peso-denominated net monetary assets and adjustments to reduce the carrying value of Argentine lease and well equipment inventory to market value, respectively. Other expense for 2000, 1999 and 1998 include non-cash mark-to-market charges for changes in the fair values of non-hedge financial instruments of $58.5 million, $27.0 million and $21.2 million, respectively.

(d) The 1998 working capital deficit includes $306.5 million of current maturities of long-term debt.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

2001 Performance

The year ended December 31, 2001 was highlighted by a very successful drilling program which further complements the foundation for significant production growth established by the Company's drilling program in 2000; the continuation of the Company's financial and operating discipline that resulted in a further decline in the Company's ratio of debt to book capitalization from 64 percent as of December 31, 2000 to 55 percent as of December 31, 2001; a $45.5 million, or 11 percent, increase in net cash provided by operating activities as compared to that of the preceding year; the repurchase of an additional 830,400 shares of the Company's common stock at an average per share cost of $15.69; and a highly successful hedging program.

During the years ended December 31, 2001 and 2000, the Company recorded net income of $100.0 and $152.2 million ($1.00 and $1.53 per diluted share), respectively, as compared to a net loss of $22.5 million ($.22 per share) during the year ended December 31, 1999. Compared to 2000, the Company's 2001 total revenues decreased by $36.2 million, or four percent, including a $5.7 million decrease in oil and gas revenues. The decrease in oil and gas revenues was due to a four percent decline in BOE sales volumes, partially offset by increases in average oil and gas prices. Compared to 2000, the Company's 2001 total costs and expenses increased by $14.5 million, or 1.9 percent. The modest increase in total costs and expenses included a $40.4 million increase in exploration and abandonments, which is primarily due to the Company's increased exploration program in 2001; a $30.0 million decrease in interest expense, primarily due to reductions in market interest rates and the interest savings associated with the early extinguishment of the remaining 11-5/8 percent and 10-5/8 percent senior subordinated notes and $38.7 million of the 9-5/8 percent senior notes; and a $27.6 million decrease in other expense, primarily due to declines in non-hedge derivative mark-to-market charges.

During the year ended December 31, 2001, the Company increased net cash provided by operating activities to $475.6 million, as compared to $430.1 million during 2000 and $255.2 million during 1999. The disciplined investment of net cash provided by operating activities, together with proceeds from the divestiture of non-strategic assets of $113.5 million and $102.7 million during 2001 and 2000, respectively, have allowed the Company to reduce its outstanding indebtedness by $168.6 million during the two years ended December 31, 2001.

During 2001, the Company's successful capital investment activities increased proved reserves to 671 MMBOE, reflecting the effects of strategic acquisitions of properties in the Company's core operating areas and a successful drilling program which resulted in the replacement of 208 percent of production at an acquisition and finding cost per BOE of $7.49. During the three years ended December 31, 2001, Pioneer has replaced 184 percent of production at an acquisition and finding cost per BOE of $4.74. Costs incurred for the year ended December 31, 2001 totaled $646.6 million, including $170.8 million of proved and unproved property acquisitions and $475.8 million of exploration and development drilling and seismic expenditures.

During December 2001, the limited partners of 42 of the Company's 46 affiliated partnerships approved an agreement and plan of merger among Pioneer, Pioneer Natural Resources USA, Inc. ("Pioneer USA"), a wholly-owned subsidiary of Pioneer, and the participating partnerships. As a result, those partnerships merged with and into Pioneer USA. This strategic acquisition was funded by the issuance of 5.7 million shares of common stock valued at $104.3 million and increased proved reserves in the Company's Spraberry oil field by approximately 29 MMBOE.

During 2001, the Company participated in discoveries at Falcon, Stirrup, Oneida and Ozona Deep prospects in the Gulf of Mexico and in the Olowi Block offshore Gabon. Additionally, exploration drilling confirmed the presence of gas offshore South Africa. The Company's development activities are increasingly focused on its "Big 4" development projects: the Canyon Express, Devils Tower and Falcon projects in the deepwater Gulf of Mexico and the Sable project in the shallow waters offshore South Africa. The Company has budgeted approximately $180 million of 2002 development expenditures for the Big 4 projects. See "Item 2. Properties" for additional information regarding the Company's finding costs and reserve replacement, property descriptions and drilling activities.

See "Results of Operations", below, for more in-depth discussions of the Company's oil and gas producing activities, including discussions pertaining to oil and gas production volumes, prices, hedging activities, costs and expenses, capital commitments, capital resources and liquidity.

2002 Outlook

Commodity prices. During 2001, commodity prices declined from historically high levels at the beginning of the year to historically moderate levels by year end. The Company's outlook for 2002 commodity prices is uncertain. Significant factors that will impact 2002 commodity prices include the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations are able to manage oil supply through export quotas and the overall North American gas supply and demand fundamentals. Pioneer will continue to moderate its debt levels, follow cost management measures and strategically hedge oil and gas price risk to mitigate the impact of price volatility on its oil, NGL and gas revenues.

As of December 31, 2001, the Company had hedged 9,463 barrels per day ("Bblpd") of 2002 oil production under swap contracts with a weighted average fixed price to be received of $26.23 per Bbl and 6,000 Bblpd of first and second quarter 2002 oil production under collar contracts with a minimum or "floor" price to be received of $25.00 per Bbl and a maximum or "ceiling" price to be received of $28.61 per Bbl. The Company had also hedged 165,205 Mcf per day ("Mcfpd") of 2002 gas production under swap contracts with a weighted average fixed price to be received of $4.19 per MMBtu and 20,000 Mcfpd of 2002 gas production under collar contracts with a floor price of $4.50 per MMBtu and a ceiling price of $6.00 per MMBtu. During January and February 2002, the Company increased its 2002 commodity hedge positions by entering into 4,000 Bblpd of July through December oil swap contracts with average per Bbl fixed prices of $21.55, 50,000 Mcfpd of April through December costless collar contracts having floor prices of $2.40 per MMBtu and average ceiling prices of $3.08 per MMBtu and 50,000 Mcfpd of August through December costless collar contracts having floor prices of $2.50 per MMBtu and ceiling prices of $3.25 per MMBtu. Additionally, the Company has deferred oil hedge gains of $3.9 million that will be recognized as oil revenue during the first six months of 2002 and $46.2 million of deferred gas hedge losses that will be recognized as gas revenue during 2002. See Note H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's open hedge positions at December 31, 2001 and their related prices. Also see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional disclosure about the Company's commodity related derivative financial instruments.

First quarter 2002. Based on current estimates, the Company expects that its first quarter worldwide production will average 108,000 to 110,000 BOE per day. First quarter production costs are expected to average $4.60 to $4.90 per BOE based on recent NYMEX strip prices for oil and gas. Depreciation, depletion and amortization expense is expected to average $5.15 to $5.30 per BOE, and total exploration and abandonment expense is expected to be $15 million to $30 million. General and administrative expense is expected to be $11 million to $12 million during the first quarter of 2002, which is higher than in prior quarters due to a reduction in overhead reimbursements from the 42 affiliated limited partnerships that were acquired in December 2001. Interest expense is expected to be $30 million to $32 million during the first quarter of 2002. Cash taxes are expected to range from $1 million to $2 million, as the Company benefits from the carryforward of prior years' net operating losses in the United States and Canada. For the first quarter of 2002, costs incurred for oil and gas producing activities is expected to range from $90 million to $100 million.

Pioneer continues to monitor the political and economic environment in Argentina. The Company's production forecasts have been adjusted to reflect the postponement of drilling in the country. In addition, the devaluation of the Argentine peso is expected to result in a near-term reduction in revenues, partially offset by a reduction in operating and administrative costs; and the recognition of remeasurement gains or losses, the impact of which cannot currently be accurately estimated. For the fourth quarter of 2001, Argentina represented 15 percent, or $18.9 million, of Pioneer's net cash flow from oil and gas operations.

Production growth. The Company expects that its annual 2002 worldwide production will be approximately 42 to 44 MMBOE, including approximately 3 MMBOE of initial production from Canyon Express facilities during the last half of the year. Worldwide production in 2003 and 2004 is expected to increase as production commences from the

Company's deepwater Gulf of Mexico Falcon gas and Devils Tower oil projects and the Sable oil project in South Africa, coupled with a full year of production from Canyon Express. The Company currently anticipates that daily production rates, on a BOE basis, will increase by 55 percent to 60 percent from the first quarter of 2002 to mid-2003, once these projects are all producing.

Capital expenditures. During 2002, the Company plans to decrease costs incurred for oil and gas producing activities to approximately $375 million, of which approximately $90 million, or 24 percent, has been budgeted for exploration expenditures and $285 million, or 76 percent, has been budgeted for development drilling and facility costs. The Company's 2002 capital budget is allocated approximately 72 percent to the United States, four percent to Argentina, seven percent to Canada and 17 percent to Africa. The Company's 2002 capital budget for the United States includes $135 million of development capital for the Canyon Express, Falcon and Devils Tower deepwater Gulf of Mexico projects. During 2002, the Company has planned exploration drilling in the Gulf of Mexico, the onshore Gulf Coast area, Canada, Gabon, Tunisia and South Africa. During the years ended December 31, 2003 and 2004, the Company expects to expend approximately $130 million and $115 million, respectively, of capital for development drilling and facility costs related to its proved undeveloped reserves.

Critical Accounting Policies

The Company prepares its consolidated financial statements for inclusion in this Report in accordance with accounting principles that are generally accepted in the United States ("GAAP"). See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a comprehensive discussion of the Company's significant accounting policies. GAAP represents a comprehensive set of accounting and disclosure rules and requirements, the application of which requires management judgements and estimates including, in certain circumstances, choices between acceptable GAAP alternatives. Following is a discussion of the Company's most critical accounting policies, judgements and uncertainties that are inherent in the Company's application of GAAP:

Accounting for oil and gas producing activities. The accounting for and disclosure of oil and gas producing activities requires the Company's management to choose between GAAP alternatives and to make judgements about estimates of future uncertainties.

Successful efforts method of accounting. The Company utilizes the successful efforts method of accounting for oil and gas producing activities as opposed to the alternate acceptable full cost method. In general, the Company believes that, during periods of active exploration, net assets and net income (loss) are more conservatively measured under the successful efforts method of accounting for oil and gas producing activities than under the full cost method. The critical difference between the successful efforts method of accounting and the full cost method is as follows: under the successful efforts method, exploratory dry holes and geological and geophysical exploration costs are charged against net income (loss) during the periods in which they occur; whereas, under the full cost method of accounting, such costs and expenses are capitalized as assets, pooled with the costs of successful wells and charged against the net income (loss) of future periods as a component of depletion expense. During 2001, the Company recognized exploration and abandonment expense of $127.9 million, $87.6 million and $66.0 million, respectively, under the successful efforts method.

Proved reserve estimates. Estimates of the Company's proved reserves included in this Report are prepared in accordance with GAAP and SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

The Company's proved reserve information included in this Report is based on estimates it prepared. Estimates prepared by others may be higher or lower than the Company's 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 Company's stockholders should not assume that the present value of future net cash flows is the current market value of the Company's estimated proved reserves. In accordance with SEC requirements, the Company based the estimated discounted future net cash flows from proved reserves 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 Company's estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, the rate at which the Company records depletion 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 fields. In addition, the decline in proved reserve estimates may impact the outcome of the Company's assessment of its oil and gas producing properties for impairment.

Impairment of proved oil and gas properties. The Company reviews its long-lived proved properties to be held and used whenever management judges that events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. Management assesses whether or not an impairment provision is necessary based upon management's outlook of future commodity prices and net cash flows that may be generated by the properties. Proved oil and gas properties are reviewed for impairment by depletable pool, which is the lowest level at which depletion of proved properties is calculated.

Impairment of unproved oil and gas properties. Management periodically assesses individually significant unproved oil and gas properties for impairment, on a project-by-project basis. Management's assessment of the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects impact the amount and timing of impairment provisions.

Assessments of functional currencies. 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 U.S. dollar is the functional currency of all of the Company's international operations except Canada. The assessment of functional currencies can have a significant impact on periodic results of operations and financial position.

Argentine economic and currency measures. The accounting for and remeasurement of the Company's Argentine balance sheet as of December 31, 2001 reflects management's assumptions regarding some uncertainties unique to Argentina's current economic situation. See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of the assumptions utilized in the preparation of these financial statements. 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, (i) the realized prices the Company receives for the commodities it produces and sells as a result of new export taxes or higher production taxes; (ii) the timing of repatriations of excess cash flow to the Company's corporate headquarters in the United States; (iii) the Company's asset valuations; and (iv) peso-denominated monetary assets and liabilities.

Deferred tax asset valuations. 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 since many assumptions are utilized in the assessments that may prove to be incorrect in the future.

New Accounting Pronouncement

The Financial Accounting Standards Board ("FASB") periodically issues Statements of Financial Accounting Standards, which represent changes in or additions to GAAP. During the year ended December 31, 2001, the FASB issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"). SFAS 143 amends Statement of Financial Accounting Standards No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies" ("SFAS 19") to require that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. Under the provisions of SFAS 143, such asset retirement costs are capitalized as part of the carrying value of the long-lived asset. Under the provisions of SFAS 19, asset retirement obligations are recognized using a cost-accumulation approach. The Company currently records significant asset retirement obligations through the unit-of-production method, except for such liabilities assumed in business combinations, which are recorded at their estimated fair values. The provisions of SFAS 143 are effective for financial statements issued for fiscal years beginning after June 15, 2002. The Company plans to adopt the provisions of SFAS 143 no later than January 1, 2003. The Company does not expect that the adoption of SFAS 143 will have a significant impact on its future financial position or results of operations.

Results of Operations

Oil and gas revenues. Revenues from oil and gas operations totaled \$847.0 million during 2001, as compared to \$852.7 million during 2000 and \$644.6 million during 1999, representing a .7 percent decrease from 2000 to 2001 and a 32 percent increase from 1999 to 2000. The revenue decrease from 2000 to 2001 is due to a four percent decline in BOE sales volumes and a 15 percent decline in NGL price, partially offset by a 15 percent increase in gas price, including the effects of gas hedges. The revenue increase from 1999 to 2000 reflects year-to-year increases in average reported commodity prices, including the effects of commodity hedges, of 56 percent, 74 percent and 48 percent for oil, NGL and gas, respectively, partially offset by a 15 percent decrease in BOE production. The declines in production were primarily attributable to normal well production declines and 1999 asset divestitures. Excluding the production associated with assets divested during 2000 and 1999, BOE production declined by approximately one percent during 2000 as compared to 1999.

The following table provides production and price data relevant to the analysis of the Company's revenues from oil and gas operations:

	Year ended December 31,		
	2001	2000	1999
Production:			
Oil (MBbls)	12,498	12,535	15,454
NGLs (MBbls)	7,800	8,379	9,237
Gas (MMcf)	127,865	135,843	158,457
Total (MBOE)	41,609	43,555	51,101
Average daily production:			
Oil (Bbls)	34,241	34,249	42,339
NGLs (Bbls)	21,370	22,894	25,308
Gas (Mcf)	350,314	371,157	434,130
Total (BOE)	113,997	119,002	140,002
Average reported prices:			
Oil (per Bbl)			
United States	$ 24.34	$ 22.07	$ 15.03
Argentina	$ 23.79	$ 29.09	$ 18.41
Canada	$ 21.87	$ 27.50	$ 13.28
Worldwide	$ 24.12	$ 24.01	$ 15.36
NGL (per Bbl)			
United States	$ 16.88	$ 20.05	$ 11.61
Argentina	$ 19.29	$ 22.91	$ 11.30
Canada	$ 21.11	$ 24.32	$ 12.62
Worldwide	$ 17.14	$ 20.27	$ 11.64
Gas (per Mcf)			
United States	$ 4.10	$ 3.50	$ 2.17
Argentina	$ 1.31	$ 1.19	$ 1.10
Canada	$ 2.86	$ 2.88	$ 1.82
Worldwide	$ 3.23	$ 2.81	$ 1.90
Percentage increase (decrease) in average worldwide reported prices:			
Oil	-	56	17
NGL	(15)	74	31
Gas	15	48	4

Hedging activities. The oil and gas prices that the Company reports are based on the market price received for the commodities adjusted by the results of the Company's hedging activities. The Company utilizes commodity derivative contracts (swaps and collars) in order to (i) reduce the effect of price volatility on the commodities the Company produces and sells, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce price risk associated with certain capital projects. See Note H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information concerning the impact to oil and gas revenues during 2001, 2000 and 1999 from the Company's hedging activities, the Company's open hedge positions at December 31, 2001 and their related prices and descriptions of the Company's hedge and non-hedge commodity derivatives. Also see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional disclosure about the Company's commodity related derivative financial instruments.

Interest and other revenue. The Company recorded interest and other income totaling $21.8 million, $25.8 million and $89.7 during 2001, 2000 and 1999 respectively. The Company's interest and other income is comprised of revenue that is not directly attributable to oil and gas producing activities or oil and gas property divestitures. The significant decrease in interest and other income during 2000 is primarily attributable to a non-recurring excise tax refund of $30.2 million and a non-recurring option fee of $41.8 million recognized by the Company during 1999. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding interest and other income.

Gain (loss) on disposition of assets. During the year ended December 31, 2001, the Company realized $113.5 million of cash proceeds from asset divestitures and, associated therewith, recorded net gains of $7.7 million. The proceeds derived from asset divestitures during 2001 included $85.4 million from the early termination of hedge derivatives, $12.7 million from the sale of the Company's remaining holdings in the common stock of a non-affiliated entity, $12.0 million from the sale of certain oil properties in Canada and $3.3 million from the sale of other corporate assets. The proceeds from the early termination of hedge derivatives represent deferred hedge gains that will be recognized as increases to oil and gas revenues in future periods (see Note H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data"). The Company recorded a gain of $8.1 million from the sale of the remaining holdings in the common stock of the non-affiliated entity and a loss of $1.1 million and a gain of $.7 million from the sales of oil and gas properties and other corporate assets, respectively.

During 2000, the Company completed the divestiture of certain assets for proceeds of $102.7 million. Associated therewith, the Company recorded a net gain on disposition of assets of $34.2 million. The 2000 divestitures included the sale of common stock of a non-affiliated entity for net proceeds of $59.7 million, from which the Company recognized a gain on disposition of assets of $34.3 million. The Company also sold certain oil and gas producing properties and other assets during 2000 for proceeds of $43.0 million, from which the Company recognized a loss on disposition of assets of $.1 million.

During 1999, the Company realized proceeds from asset divestitures of $420.5 million and recognized a net loss on disposition of assets of $24.2 million.

The net cash proceeds from asset divestitures during 2001, 2000 and 1999 were used, together with net cash flows provided by operating activities, to finance strategic additions to oil and gas properties, to reduce outstanding indebtedness and other for general corporate needs. See Note K of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding asset divestitures.

Production costs. Total production costs per BOE increased in 2001 and 2000 by 16 percent and 39 percent, respectively. In general, lease operating expenses and workover expenses represent the components of production costs over which the Company has management control, while production taxes, ad valorem taxes and field fuel expenses are directly related to commodity price changes. The increase in production costs during 2001 is primarily due to increases in field fuel expense as a result of higher North American average gas prices, higher ad valorem taxes which are computed using prior year average annual commodity prices and to declines in the third party gas processing and treating margin component of lease operating expenses. The increase in per BOE production costs in 2000 as compared to 1999 is primarily due to significant increases in those expenses that are directly related to commodity prices and, to a lesser extent, inflation in field service expenses. The following table provides the components of the Company's production costs during the years ended December 31, 2001, 2000 and 1999:

	Year Ended December 31,		
	2001	2000 (per BOE)	1999
Lease operating expenses	$ 2.76	$ 2.42	$ 2.11
Taxes:			
Production	.74	.77	.39
Ad valorem	.49	.29	.31
Field fuel expenses	.88	.71	.21
Workover expenses	.17	.15	.10
Total production costs	$ 5.04	$ 4.34	$ 3.12

Depletion, depreciation and amortization expense. The Company's total depletion, depreciation and amortization expense per BOE was $5.35, $4.93 and $4.62 for the years ended December 31, 2001, 2000 and 1999, respectively. Depletion expense, the largest component of depletion, depreciation and amortization, was $5.02, $4.57 and $4.27 per BOE during the years ended December 31, 2001, 2000 and 1999, respectively, and depreciation and amortization of other property and equipment was $.33, $.36 and $.35 per BOE during each of the respective years. During 2001, the increase in per BOE depletion expense is primarily associated with decreases in United States production, which has a lower cost basis relative to combined Argentine and Canadian per BOE cost basis, and to downward revisions to proved reserves as a result of lower commodity prices. The increase in per BOE depletion expense during 2000 is primarily due to an increase in the Company's Argentine and Canadian proved property basis as a result of reclassifying unproved property basis associated with the Company's exploration and extension drilling success to proved property and to a higher proportionate share of the Company's production being produced from Argentina.

Impairment of oil and gas properties. The Company reviews its proved properties for impairment whenever events or circumstances indicate a decline in the recoverability of the carrying value of the Company's assets may have occurred.

The Company periodically assesses its unproved properties to determine whether they have been impaired. An unproved property may be impaired if the Company does not intend to drill the prospect as a result of downward revisions to potential reserves, if the results of exploration or the Company's outlook for future commodity prices indicate that the potential reserves are not sufficient to generate net cash flows to recover the investment required by the project, or if the Company intends to sell the property for less than its carrying value. The Company regularly assesses its unproved oil and gas properties for impairment and, during the year ended December 31, 1999, recognized a non-cash impairment charge of $17.9 million to reduce the carrying value of its unproved East Texas gas properties. See Critical Accounting Policies above and Notes B and L of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information pertaining to the Company's accounting policies regarding assessments of impairment and specific information about the 1999 impairment of unproved properties.

Exploration and abandonments/geological and geophysical costs. Exploration and abandonments/geological and geophysical costs totaled $127.9 million, $87.6 million and $66.0 million for the years ended December 31, 2001, 2000 and 1999, respectively. The following table sets forth the components of the Company's 2001, 2000 and 1999 exploration and abandonments/geological and geophysical costs:

	United States	Argentina	Canada	Other Foreign	Total
			(in thousands)		
Year Ended December 31, 2001:					
Geological and geophysical costs	$ 29,620	$ 6,541	$ 2,373	$ 13,678	$ 52,212
Exploratory dry holes	34,883	6,040	5,473	10,432	56,828
Leasehold abandonments and other	5,546	11,276	2,036	8	18,866
	$ 70,049	$ 23,857	$ 9,882	$ 24,118	$ 127,906
Year Ended December 31, 2000:					
Geological and geophysical costs	$ 22,033	$ 6,881	$ 2,273	$ 7,761	$ 38,948
Exploratory dry holes	11,745	6,987	887	8,396	28,015
Leasehold abandonments and other	7,089	11,520	1,971	7	20,587
	$ 40,867	$ 25,388	$ 5,131	$ 16,164	$ 87,550
Year Ended December 31, 1999:					
Geological and geophysical costs	$ 17,207	$ 3,399	$ 315	$ 7,498	$ 28,419
Exploratory dry holes	15,591	3,441	978	(275)	19,735
Leasehold abandonments and other	8,427	7,169	2,216	8	17,820
	$ 41,225	$ 14,009	$ 3,509	$ 7,231	$ 65,974

The increase in 2001 exploration costs, as compared to 2000, is primarily due to increased geological and geophysical costs that are supportive of future exploratory drilling, increased exploratory drilling in the Gulf of Mexico and Argentina and an exploratory dry hole drilled in Tunisia. The increase in 2000 exploration costs, as compared to 1999, is primarily due to increased geological and geophysical costs, unproved leasehold abandonments associated with exploratory dry holes in Argentina and dry hole costs associated with exploratory drilling in South Africa. Approximately 34 percent of the Company's 2001 costs incurred for oil and gas producing activities were exploration costs as compared to 38 percent in 2000 and 32 percent in 1999.

Administrative and reorganization expenses. The Company's administrative expense totaled $37.0 million ($.89 per BOE), $33.3 million ($.76 per BOE) and $40.2 million ($.79 per BOE) during the years ended December 31, 2001, 2000 and 1999. The increase in administrative expense during 2001, as compared to 2000, is primarily due to an increase in compensation expense. The decline in per BOE administrative expense during 2000 was due to the reorganization measures initiated by the Company during 1998 and completed in 1999. Those reorganization measures included the centralization in Irving, Texas of certain operational and administrative functions previously based in Midland, Texas; the closings of the Company's regional offices in Oklahoma City, Oklahoma, Corpus Christi, Texas, and Houston, Texas; workforce reductions; and, other initiatives. As a direct result of those measures, the Company recognized reorganization charges of $8.5 million during 1999. See Note M of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for specific information regarding reorganization costs paid during 2001, 2000 and 1999, and unpaid reorganization costs as of December 31, 2001, 2000 and 1999.

Interest expense. Interest expense was $132.0 million, $162.0 million and $170.3 million for the years ended December 31, 2001, 2000 and 1999, respectively. Interest expense decreased during 2001, as compared to 2000, due to a decrease in the Company's weighted average borrowing rate and the interest savings associated with the early extinguishment of the Company's outstanding 11-5/8 percent and 10-5/8 percent senior notes and $38.7 million of the Company's 9-5/8 percent senior notes. Interest expense decreased during 2000, as compared to 1999, primarily due to a decrease in the Company's weighted average debt outstanding for the year. This decline was offset, to a certain extent, by higher interest rates in 2000 as compared to 1999.

Other expenses. Other expenses were $39.6 million during 2001, as compared to $67.2 million during 2000 and $34.6 million during 1999. Other expenses in 2001 include $11.4 million of commodity derivative settlements that did not qualify for hedge treatment under Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities"; $9.9 million of marketing losses incurred to transport and sell purchased Canadian gas to a Chicago, Illinois sales point; $7.7 million of losses from the remeasurement of the Company's Argentine peso-denominated net monetary assets and an adjustment to reduce the carrying value of Argentine lease and well equipment inventory to market value (see Note B of Note to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding currency remeasurement); $6.0 million of bad debt expense related to derivative contracts with Enron North America Corp. and $4.6 million of other expenses.

The increase in other expenses during 2000, as compared to 1999, is primarily attributable to increases in mark-to-market provisions on non-hedge derivative financial instruments. Such mark-to-market provisions during 2000 included $42.0 million associated with non-hedge commodity derivatives that matured in December 2000, $14.6 million associated with the Company's non-hedge Btu swap agreements and $1.9 million associated with a series of non-hedge forward foreign exchange swap agreements that matured in December 2000. Mark-to-market provisions in 1999 included $21.2 million associated with non-hedge commodity derivatives and $11.9 million associated with an investment in the common stock of a non-affiliated public entity, partially offset by $5.9 million of mark-to-market income recognized on a series of forward foreign exchange swap agreements and income of $.2 million associated with the Company's Btu swap agreements.

During 2001, the Company entered into offsetting swap agreements that have fixed the prices that are to be received and paid by the Company under the Btu swap agreements. Consequently, the fair values of the Company's Btu swap agreements, which represent a discounted liability to the Company of $19.4 million as of December 31, 2001, are no longer sensitive to the changes in oil or gas commodity prices. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Notes C and H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for specific disclosures pertaining to the Company's derivative financial instruments.

Income tax provisions (benefits). The Company recognized a consolidated income tax provision of $4.0 million during 2001 and consolidated income tax benefits of $6.0 million and $.6 million during 2000 and 1999. The Company's consolidated tax provision for the year ended December 31, 2001 is comprised of current U.S. state and local taxes of $1.1 million; current foreign tax provision of $10.5 million; and deferred foreign tax benefits of $7.6 million. The Company's consolidated tax benefit in 2000 is comprised of a $10.6 million deferred tax benefit in Argentina, partially offset by $4.6 million of current taxes paid in Argentina. Due to uncertainties regarding the Company's ability to realize net operating loss carryovers and tax credit carryovers prior to their scheduled expirations, the Company did not recognize deferred income tax benefits associated with its operating results for 1999. Although realization is not assured for the Company's remaining deferred tax assets, the Company believes it is more likely than not that they will be realized through future taxable earnings or alternative tax planning strategies. However, the net deferred tax assets could be reduced further if the Company's estimate of taxable income in future periods is significantly reduced or alternative tax planning strategies are no longer viable. As a result of this situation, it is likely that the Company's effective tax rate in 2002 will be minimal. See Note O of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the Company's income taxes and deferred tax asset valuation reserves.

Extraordinary items. The Company redeemed the remaining $22.5 million of its outstanding 11-5/8 percent senior subordinated discount notes due July 1, 2006 and $6.8 million of its outstanding 10-5/8 percent senior subordinated notes due July 1, 2006 during July 2001, and redeemed $38.7 million of its 9-5/8 percent senior notes due April 1, 2010 during the fourth quarter of 2001. Associated with these redemptions, the Company recognized an extraordinary loss, net of taxes, of $3.8 million during 2001. During 2000, the Company replaced its prior credit facility, which was scheduled to mature August 7, 2002, with a new $575 million corporate credit facility due March 1, 2005 (the "Credit Agreement"). Associated therewith, the Company recognized a $12.3 million extraordinary loss on early extinguishment of debt.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. The Company's primary needs for cash are for exploration, development and acquisitions of oil and gas properties, repayment of contractual obligations and working capital obligations.

Oil and gas properties. The Company's cash expenditures for additions to oil and gas properties during 2001, 2000 and 1999 totaled $529.7 million, $299.7 million and $179.7 million, respectively. The Company's 2001 expenditures were internally funded by $475.6 million of net cash provided by operating activities and a portion of the

Company's $113.5 million of proceeds from disposition of assets. The Company's 2000 and 1999 capital expenditures were internally funded by net cash provided by operating activities.

The Company strives to maintain its indebtedness at moderate levels in order to provide sufficient financial flexibility to take advantage of future opportunities. The Company's $375 million capital budget for 2002 includes $180 million of expenditures for the development of the Company's Canyon Express, Devils Tower, Falcon and Sable projects which may cause capital expenditures to exceed internally generated cash flows. To the extent that the Company's capital expenditures during 2002 exceed cash provided by operating activities, the Company may increase its outstanding indebtedness by utilizing unused borrowing capacity under its Credit Agreement or, alternatively, the Company may use other sources of capital as described in "Capital resources" below.

Contractual obligations. The Company's contractual obligations include long-term debt, operating leases, Btu swap agreements, terminated commodity hedges and other contracts. Contractual obligations for which the ultimate settlement amounts are not fixed and determinable include derivative contracts that are sensitive to future changes in commodity prices, currency exchange rates and interest rates. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for a table of changes in the fair value of the Company's derivative contract assets and liabilities during the year ended December 31, 2001. The following table summarizes the Company's payments due by period for fixed and determinable contractual obligations:

	Payments Due by Year			
	2002	2003-2004	2005-2006	Thereafter
	(in thousands)			
Long-term debt (a)	$ -	$ -	$ 445,998	$ 1,121,306
Operating leases (b)	5,942	63,919	46,230	28,538
Btu swap agreements (c)	7,175	14,358	-	-
Terminated commodity hedges (c)	30,209	-	-	-
	$ 43,326	$ 78,277	$ 492,228	$ 1,149,844

(a) See Note D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".
(b) See Note G of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".
(c) See Note H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

Working capital. Funding for the Company's working capital obligations is provided by internally-generated cash flow. Funding for the repayment of principal and interest on outstanding debt and the Company's capital expenditure program may be provided by any combination of internally-generated cash flow, proceeds from the disposition of non-strategic assets or alternative financing sources as discussed in "Capital resources" below.

Capital resources. The Company's primary capital resources are net cash provided by operating activities, proceeds from financing activities and proceeds from sales of non-strategic assets. The Company expects that these resources will be sufficient to fund its capital commitments in 2002.

Operating activities. Net cash provided by operating activities during 2001, 2000 and 1999 were $475.6 million, $430.1 million and $255.2 million, respectively. During 2001, net cash provided by operating activities increased by $45.5 million, or 11 percent, as compared to that of 2000. The increase in 2001 is primarily due to higher commodity prices as compared to 2000 and an increase in trade receivable collections. Net cash provided by operating activities increased 69 percent during 2000 from that of 1999, primarily as a result of favorable commodity prices and cost management measures. Net cash provided by operating activities during 1999 decreased 19 percent from that of 1998 primarily as a result of declines in production volumes due to oil and gas property divestitures, partially offset by increases in commodity prices and decreases in production and administrative costs.

Financing activities. During the years ended December 31, 2001, 2000 and 1999, the Company has used $64.0 million, $244.1 million and $479.1 million, respectively, of net cash in financing activities. Over the three year period ended December 31, 2001, the Company has used $620.8 million of cash for net reductions in long-term borrowings and has reduced its ratio of debt to book capitalization to 55 percent as of December 31, 2001, from 69 percent as of

December 31, 1999. Additionally, the Company has entered into financing transactions with the intent of reducing its costs of capital and increasing liquidity through the extension of debt maturities.

During 2001, the Company entered into interest rate swap contracts to hedge the fair value of its 6-1/2 percent senior notes due in 2008, its 8-7/8 percent senior notes due in 2005 and its 8-1/4 percent senior notes due in 2007. The Company also entered into interest rate swaps to hedge a portion of its interest rate risk under the Credit Agreement. These swap contracts reduced the Company's interest expense by $7.3 million during 2001. See Note H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplemental Data" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for more information about the Company's hedging activities.

As is further described in "Results of Operations" above, during 2001, the Company redeemed its remaining 11-5/8 percent and 10-5/8 percent senior subordinated notes due July 1, 2006, and $38.7 million of its 9-5/8 percent senior notes due April 1, 2010.

At December 31, 2001, the Company had a $575 million corporate credit facility with a syndicate of banks that matures on March 1, 2005. Outstanding borrowings under the corporate credit facility totaled $294 million as of December 31, 2001. In addition, the Company has five outstanding senior note issuances at December 31, 2001. Such debt issuances consist of (i) $150 million aggregate principal amount of 8-7/8 percent senior notes due in 2005; (ii) $150 million aggregate principal amount of 8-1/4 percent senior notes due in 2007; (iii) $350 million aggregate principal amount of 6-1/2 percent senior notes due in 2008; (iv) $385 million aggregate remaining principal amount of 9-5/8 percent senior notes due in 2010; and, (iv) (v) $250 million aggregate principal amount of 7-1/5 percent senior notes due in 2028. Certain of the obligations above contain restrictive covenants which the Company is in compliance with as of December 31, 2000.

The weighted average interest rate on the Company's indebtedness for the year ended December 31, 2001 was 7.52 percent as compared to 8.68 percent for the year ended December 31, 2000 and 7.81 percent for the year ended December 31, 1999, taking into account the effect of interest rate swaps. See Note D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more specific information regarding the Company's long-term debt as of December 31, 2001 and 2000.

As the Company pursues its strategy, it may utilize various financing sources, including fixed and floating rate debt, convertible securities, preferred stock or common stock. The Company may also issue securities in exchange for oil and gas properties, stock or other interests in other oil and gas companies or related assets. Additional securities may be of a class preferred to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined by the Company's Board of Directors.

Sales of non-strategic assets. During 2001, 2000 and 1999, proceeds from the sale of non-strategic assets totaled $113.5 million, $102.7 million and $420.5 million (1999 includes $30 million of non-cash proceeds), respectively. The Company's 2001, 2000 and 1999 asset divestitures were comprised of hedge derivatives, common stock of a non-affiliated entity, and non-strategic United States and Canadian oil and gas properties, gas plants and other assets. The cash proceeds received from asset divestitures during 2001 were used to fund a portion of the Company's 2001 capital expenditures and for general corporate obligations. The net cash proceeds from the 2000 and 1999 asset divestitures were used to reduce the Company's outstanding indebtedness (see "Results of Operations", above, and Note K of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data").

Book capitalization and liquidity. Total debt remained constant at $1.6 billion as of December 31, 2001, as compared to total debt of $1.6 billion and $1.7 billion on December 31, 2000 and 1999, respectively. The Company's total book capitalization at December 31, 2001 was $2.9 billion, consisting of total debt of $1.6 billion and stockholders' equity of $1.3 billion. Consequently, the Company's debt to total capitalization decreased to 55 percent at December 31, 2001 from 64 percent at December 31, 2000. At December 31, 2001, the Company had $14.3 million of cash and cash equivalents on hand, compared to $26.2 million at December 31, 2000. The Company's ratio of current assets to current liabilities was 1.12 at December 31, 2001 and .88 at December 31, 2000. Including $27.9 million of undrawn and outstanding letters of credit, the Company has $253.1 million of unused borrowing capacity available under its Credit Agreement as of December 31, 2001.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The following quantitative and qualitative information is provided about financial instruments to which the Company was a party as of December 31, 2001 and 2000, and from which the Company may incur future gains or losses from changes in market interest rates, foreign exchange rates, commodity prices or common stock prices. Although certain derivative contracts that the Company is a party to do not qualify as hedges, the Company does not enter into derivative or other financial instruments for trading purposes.

The fair value of the Company's derivative contracts are determined based on counterparties' estimates and valuation models. The Company has not changed its valuation method during 2001. During 2001, the Company only entered into costless swap and collar contracts. See Note H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's derivative contracts, including deferred gains and losses on terminated derivative contracts. The following table reconciles the changes that occurred in the fair values of the Company's open derivative contracts during 2001:

	Derivative Contract Assets (Liabilities)			
	Commodity	Interest Rate	Foreign Exchange Rate	Total
	(in thousands)			
Fair value of contracts outstanding as of December 31, 2000	$ (165,560)	$ 6,216	$ -	$(159,344)
Changes in contract fair value	396,921	(159)	61	396,823
Contract realizations:				
Maturities	(3,601)	(4,524)	-	(8,125)
Termination - cash settlements	(64,240)	(21,170)	-	(85,410)
Termination - future obligations	22,311	-	-	22,311
Termination - future receivables	(5,277)	-	-	(5,277)
Fair value of contracts outstanding as of December 31, 2001	$ 180,554	$ (19,637)	$ 61	$ 160,978

Quantitative Disclosures

Interest rate sensitivity. The following tables provide information, in U. S. dollar equivalent amounts, about derivative financial instruments and other financial instruments to which the Company was a party as of December 31, 2001 and 2000, which are sensitive to changes in interest rates. For debt obligations, the tables present maturities by expected maturity dates together with the weighted average interest rates expected to be paid on the debt, given current contractual terms and market conditions. For fixed rate debt, the weighted average interest rate represents the contractual fixed rates that the Company is obligated to periodically pay on the debt as of December 31, 2001 and 2000. For variable rate debt, the average interest rate represents the average rates being paid on the debt projected forward proportionate to the forward yield curve for the six-month London Interbank Offered Rate as of February 28, 2002 for the Interest Rate Sensitive table as of December 31, 2001 and the forward yield curve for United States treasury securities for the Interest Rate Sensitivity table as of December 31, 2000.

The accompanying tables also provide information about interest rate swap agreements entered into by the Company during 2001 and 2000. The interest rate swap agreements as of December 31, 2001 hedge (i) the fair value of the Company's 8-1/4 percent senior notes due August 15, 2007; (ii) the fair value of the Company's 6-1/2 percent senior notes due January 15, 2008; and (iii) a portion of the interest rate risk associated with the Company's Credit Agreement. The Interest Rate Sensitivity table as of December 31, 2000 includes information about interest rate swap agreements that the Company terminated during 2001 but which, as of December 31, 2000, hedged the fair value of the Company's 8-7/8 percent senior notes due April 15, 2005.

Interest Rate Sensitivity
Derivative And Other Financial Instruments as of December 31, 2001

	2002	2003	2004	2005	2006	Thereafter	Total	Asset (Liability) Fair Value
				(in thousands except interest rates)				
Total Debt:								
U.S. dollar denominated maturities:								
Fixed rate debt	$ -	$ -	$ -	$161,998	$ -	$1,121,306	$1,283,304	$(1,268,178)
Weighted average interest rate	8.06%	8.06%	8.06%	7.98%	7.95%	7.95%		
Variable rate debt	$ -	$ -	$ -	$294,000	$ -	$ -	$ 294,000	$ (294,000)
Average interest rates ...	4.38%	6.12%	6.90%	7.27%				
Interest Rate Hedge Derivatives (1):								
8-1/4% senior notes hedge:								
Notional debt amount ...	$150,000	$150,000	$150,000	$150,000	$150,000	$ 150,000	$ 150,000	$ (2,965)
Fixed rate receivable	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%		
Variable rate payable ...	6.50%	8.24%	9.02%	9.39%	9.64%	9.79%		
6-1/2% senior notes hedge:								
Notional debt amount ...	$350,000	$350,000	$350,000	$350,000	$350,000	$ 350,000	$ 350,000	$ (16,229)
Fixed rate receivable	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%		
Variable rate payable ...	5.15%	6.89%	7.67%	8.04%	8.29%	8.44%		
Credit Agreement hedge:								
Notional debt amount ...	$ 55,000						$ 55,000	$ (443)
Fixed rate payable	5.43%							
Variable rate receivable .	4.38%							

(1) The Company's 8-1/4% senior notes hedge matures August 15, 2007; the 6-1/2% senior notes hedge matures January 15, 2008; and the Credit Agreement hedge matures May 20, 2002.

Interest Rate Sensitivity
Derivative And Other Financial Instruments as of December 31, 2000

	2001	2002	2003	2004	2005	Thereafter	Total	Asset (Liability) Fair Value
				(in thousands except interest rates)				
Total Debt:								
U.S. dollar denominated maturities:								
Fixed rate debt	$ -	$ -	$ -	$ -	$150,000	$1,203,776	$1,353,776	$(1,290,250)(1)
Weighted average interest rate	8.10%	8.10%	8.10%	8.10%	8.03%	8.00%		
Variable rate debt	$ -	$ -	$ -	$ -	$225,000	$ -	$ 225,000	$ (225,000)
Average interest rates ...	6.64%	6.27%	6.18%	6.24%	6.31%			
Interest Rate Hedge Derivatives (2):								
Notional amount of interest rate swap	$150,000	$150,000	$150,000	$150,000	$150,000	$ -	$ 150,000	$ 6,216
Fixed interest rate received .	8.88%	8.88%	8.88%	8.88%	8.88%			
Variable interest rate paid ..	7.17%	6.77%	6.67%	6.74%	6.81%			

(1) Excludes $30.9 million of debt instruments for which fair values were insignificant and no estimate of fair value was performed as of December 31, 2000.

(2) The Company's interest rate hedge derivatives as of December 31, 2000 had a scheduled maturity of April 15, 2005.

Foreign exchange rate sensitivity. The following table provides information, in U.S. dollar equivalent amounts, about derivative financial instruments that the Company was a party to as of December 31, 2001 and that were sensitive to changes in foreign exchange rates.

Foreign Exchange Rate Sensitivity
Derivative And Other Financial Instruments as of December 31, 2001

	2002	Total	Asset Fair Value
	(in thousands except interest rates)		
Foreign Exchange Rate Hedge Derivatives:			
Notional amount of foreign currency forward contracts	$ 24,752	$ 24,752	$ 61
Fixed Canadian to U.S. dollar rate paid	.6266		
Average forward Canadian dollar to U.S. dollar exchange rate as of February 28, 2002	.6250		

Commodity price sensitivity. The following tables provide information, in U.S. dollar equivalent amounts, about derivative financial instruments that the Company was a party to as of December 31, 2001 and 2000 and that are sensitive to changes in oil and gas prices. The tables segregate hedge derivative contracts from those that do not qualify as hedges.

Commodity hedge instruments. The Company hedges commodity price risk with swap and collar contracts. Swap contracts provide a fixed price for a notional amount of sales volumes. Collar contracts provide minimum ("floor") and maximum ("ceiling") prices for the Company on a notional amount of sales volumes, thereby allowing some price participation if the relevant index price closes above the floor price.

Commodity non-hedge instruments. The Company is a party to Btu swap contracts. These contracts do not qualify for hedge accounting. Under the terms of the Btu swap contracts, the Company receives 10 percent of the NYMEX oil price and pays the NYMEX gas price on a notional 13,036 MMBtu daily gas volume. During 2000, the Company entered into Btu swap contracts that offset its variable position in the Btu swap contracts for the 2001 volumes, but continued to participate for 2002 through 2004 volumes. Accordingly, these derivative instruments are presented in both the accompanying oil and gas tables for the year ended December 31, 2000. During 2001, the Company entered into Btu swap contracts that offset its remaining variable positions in the Btu swap contracts for 2002 through 2004 volumes. Consequently, the Company has no remaining market risk associated with Btu swap contracts as of December 31, 2001. As of December 31, 2001, the carrying value of the Btu swap contracts represented a discounted liability of $19.4 million.

See Notes B, C and H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of the accounting procedures followed by the Company relative to hedge and non-hedge derivative financial instruments and for specific information regarding the terms of the Company's derivative financial instruments that are sensitive to changes in oil and gas prices.

Oil Price Sensitivity
Derivative Financial Instruments as of December 31, 2001 (3)

	2002	2003	Asset Fair Value
Oil Hedge Derivatives (1):			
Average daily notional Bbl volumes:			
Swap contracts	9,463	2,975	$ 23,423
Weighted average per Bbl fixed price	$ 26.23	$ 24.02	
Collar contracts	2,975		$ 5,506
Weighted average short call per Bbl ceiling price	$ 28.61		
Weighted average long put per Bbl floor price	$ 25.00		
Average forward NYMEX oil prices (2)	$ 21.86	$ 21.54	

(1) See Note H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for hedge volumes and weighted average prices by calendar quarter for 2002 and 2003.

(2) The average forward NYMEX oil prices are based on February 28, 2002 market quotes.

(3) During January 2002, the Company entered into 4,000 Bbls per day of July through December 2002 swap contracts with average per Bbl fixed prices of $21.55. These financial instruments are not included in the table.

Oil Price Sensitivity
Derivative Financial Instruments as of December 31, 2000

	2001	2002	2003	2004	Asset (Liability) Fair Value
Oil Hedge Derivatives:					
Average daily notional Bbl volumes:					
Swap contracts	6,510				$ 8,819
Weighted average per Bbl fixed price	$ 29.27				
Collar contracts	4,479				$ (1,820)
Weighted average short call per Bbl ceiling price	$ 25.15				
Weighted average long put per Bbl floor price	$ 20.57				
Oil Non-hedge Derivatives (1):					
Daily notional MMBtu volumes under swap of NYMEX gas price for 10 percent of NYMEX WTI price	13,036	13,036	13,036	13,036	$ (25,507)
Average forward NYMEX gas prices (2)	$ 4.05	$ 4.61	$ 4.29	$ 4.35	
Average forward NYMEX oil prices (2)	$ 27.69	$ 24.15	$ 22.21	$ 21.54	

(1) Since the oil non-hedge derivatives were sensitive to changes in both oil and gas market prices, they are duplicated in the Oil Price Sensitivity and the Natural Gas Price Sensitivity tables as of December 31, 2000.

(2) The average forward NYMEX oil and gas prices are based on February 20, 2001 market quotes, except for the 2001 prices that represent locked-in prices associated with the Company's Btu swaps.

Natural Gas Price Sensitivity
Derivative Financial Instruments as of December 31, 2001 (4)

	2002	2003	2004	2005	Asset Fair Value
Natural Gas Hedge Derivatives (1) (2):					
Average daily notional MMBtu volumes:					
Swap contracts	165,205	117,500	165,000	50,000	$ 137,606
Weighted average per MMBtu fixed price	$ 4.19	$ 3.62	$ 3.84	$ 3.63	
Collar contracts	20,000				$ 14,019
Weighted average short call per MMBtu ceiling price	$ 6.00				
Weighted average long put per MMBtu floor price	$ 4.50				
Average forward NYMEX gas prices (3)	$ 2.68	$ 3.21	$ 3.42	$ 3.52	

(1) To minimize basis risk, the Company enters into basis swaps for a portion of its gas hedges to convert the index price of the hedging instrument from a NYMEX index to an index which reflects the geographic area of production. The Company considers these basis swaps as part of the associated swap and option contracts and, accordingly, the effects of the basis swaps have been presented together with the associated contracts.

(2) See Note H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for hedge volumes and weighted average prices by calendar quarter for 2002, 2003, 2004 and 2005.

(3) The average forward NYMEX gas prices are based on February 28, 2002 market quotes.

(4) During January and February 2002, the Company terminated 2003, 2004 and 2005 gas swap contracts for 117,500 MMBtu per day, 110,000 MMBtu per day and 20,000 MMBtu per day, respectively. Associated therewith, the Company received $51.4 million of cash proceeds representing deferred hedge gains. These deferred hedge gains will be recorded as increments to gas revenues as follows: $23.5 million during 2003, $26.7 million in 2004 and $1.2 million in 2005. During February 2002, the Company entered into 50,000 MMBtu per day of April through December 2002 costless collar contracts having floor prices of $2.40 per MMBtu and ceiling prices of $3.08 per MMBtu and 50,000 MMBtu per day of August through December 2002 costless collars having floor prices of $2.50 per Mcf and ceiling prices of $3.25 per MMBtu. These changes in financial instruments are not reflected in the table.

Natural Gas Price Sensitivity
Derivative Financial Instruments as of December 31, 2000

	2001	2002	2003	2004	Asset (Liability) Fair Value
Natural Gas Hedge Derivatives (1):					
Average daily notional MMBtu volumes:					
Swap contracts	76,346				$ (79,771)
Weighted average per MMBtu fixed price	$ 4.59				
Collar contracts	54,482				$ (67,281)
Weighted average short call per MMBtu ceiling price	$ 2.73				
Weighted average long put per MMBtu contingent floor price	$ 2.11				
Natural Gas Non-hedge Derivatives (2):					
Daily notional MMBtu volumes under agreement to swap NYMEX gas price for 10 percent of NYMEX WTI price	13,036	13,036	13,036	13,036	$ (25,507)
Average forward NYMEX gas prices (3)	$ 4.05	$ 4.61	$ 4.29	$ 4.35	
Average forward NYMEX oil prices (3)	$ 27.69	$ 24.15	$ 22.21	$ 21.54	

(1) To minimize basis risk, the Company enters into basis swaps for a portion of its gas hedges to convert the index price of the hedging instrument from a NYMEX index to an index which reflects the geographic area of production. The Company considers these basis swaps as part of the associated swap and option contracts and, accordingly, the effects of the basis swaps have been presented together with the associated contracts.

(2) Since the oil non-hedge derivatives were sensitive to changes in both oil and gas market prices, they are duplicated in the Oil Price Sensitivity and the Natural Gas Price Sensitivity tables as of December 31, 2000.

(3) The average forward NYMEX oil and gas prices are based on February 20, 2001 market quotes, except for the 2001 prices that represent locked-in prices associated with the Company's Btu swaps.

Other price sensitivity. As of December 31, 2000, the Company owned 613,215 shares of a non-affiliated entity having an aggregate fair value of $12.7 million. During 2001, the Company sold its shares for $12.7 million (see Notes C, E and K of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information regarding the shares sold).

Qualitative Disclosures

Non-derivative financial instruments. The Company is a borrower under fixed rate and variable rate debt instruments that give rise to interest rate risk. The Company's objective in borrowing under fixed or variable rate debt is to satisfy capital requirements while minimizing the Company's costs of capital. To realize its objectives, the Company borrows under fixed and variable rate debt instruments, based on the availability of capital, market conditions and hedge opportunities. See Note D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a discussion relative to the Company's debt instruments.

As described in "Other price sensitivity" above, the Company owned 613,215 shares of a non-affiliated entity. The Company does not routinely acquire shares of common stock of publicly traded entities for investment purposes. The shares were received by the Company in partial consideration for assets sold to the non-affiliated entity.

Derivative financial instruments. The Company has entered into interest rate, foreign exchange rate and commodity price derivative contracts to hedge interest rate, foreign exchange rate and commodity price risks. Although the Company is a party to certain derivative contracts that do not qualify for hedge accounting treatment, the Company's policy is to limit its participation in derivative contracts to those that, in the opinion of management, reduce the Company's overall economic risk.

As of December 31, 2001 and 2000, the Company was a party to the Btu swap contracts that are described more fully in Quantitative Disclosures, above, and Note H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data". These financial instruments do not qualify as hedges of commodity price risk under generally accepted accounting standards.

As of December 31, 2001, the Company's primary risk exposures associated with financial instruments to which it is a party include oil and gas price volatility, volatility in the exchange rates of the Canadian dollar and Argentine peso against the U.S. dollar and interest rate volatility. The Company's primary risk exposures associated with financial instruments have not changed significantly since December 31, 2001.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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INDEPENDENT AUDITORS' REPORT

The Board of Directors and Shareholders
Pioneer Natural Resources Company:

We have audited the accompanying consolidated balance sheets of Pioneer Natural Resources Company as of December 31, 2001 and 2000, and the related consolidated statements of operations, stockholders' equity, cash flows and comprehensive income (loss) for each of the three years in the period ended December 31, 2001. 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 consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Pioneer Natural Resources Company at December 31, 2001 and 2000, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As discussed in Note B to the consolidated financial statements, in 2001 Pioneer Natural Resources Company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities".

Ernst & Young LLP

Dallas, Texas
January 25, 2002

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

ASSETS

	December 31, 2001	December 31, 2000
Current assets:		
Cash and cash equivalents	$ 14,334	$ 26,159
Accounts receivable:		
Trade, net of reserves for doubtful accounts of $5,553 and $4,766 as of December 31, 2001 and 2000, respectively	81,616	123,497
Affiliates	595	2,157
Inventories	14,549	14,842
Deferred income taxes	6,400	4,800
Other current assets:		
Derivative assets, net of $3,153 valuation reserve as of December 31, 2001	127,074	11,608
Other	11,075	8,328
Total current assets	255,643	191,391
Property, plant and equipment, at cost:		
Oil and gas properties, using the successful efforts method of accounting:		
Proved properties	3,691,783	3,187,889
Unproved properties	187,785	229,205
Accumulated depletion, depreciation and amortization	(1,095,310)	(902,139)
	2,784,258	2,514,955
Deferred income taxes	84,319	84,400
Other property and equipment, net	21,560	25,624
Other assets, net:		
Derivative assets, net of $1,069 valuation reserve as of December 31, 2001	54,486	46,192
Other	70,787	91,873
	$ 3,271,053	$ 2,954,435

LIABILITIES AND STOCKHOLDERS' EQUITY

	2001	2000
Current liabilities:		
Accounts payable:		
Trade	$ 92,760	$ 96,646
Affiliates	6,405	5,629
Interest payable	37,410	38,142
Other current liabilities:		
Derivative obligations	36,830	24,957
Other	54,804	51,140
Total current liabilities	228,209	216,514
Long-term debt	1,577,304	1,578,776
Noncurrent derivative obligations	32,438	65,974
Other noncurrent liabilities	133,945	159,766
Deferred income taxes	13,768	28,500
Stockholders' equity:		
Preferred stock, $.01 par value; 100,000,000 shares authorized; one share issued and outstanding	-	-
Common stock, $.01 par value; 500,000,000 shares authorized; 107,422,467 shares issued at December 31, 2001; and 101,268,754 shares issued at December 31, 2000	1,074	1,013
Additional paid-in capital	2,462,272	2,352,608
Treasury stock, at cost; 3,486,073 shares at December 31, 2001 and 2,853,107 shares at December 31, 2000	(48,002)	(37,682)
Accumulated deficit	(1,323,343)	(1,422,703)
Accumulated other comprehensive income:		
Deferred hedge gains, net	201,046	-
Unrealized gain on available for sale securities	-	8,154
Cumulative translation adjustment	(7,658)	3,515
Total stockholders' equity	1,285,389	904,905
Commitments and contingencies		
	$ 3,271,053	$ 2,954,435

The accompanying notes are an integral part of these consolidated financial statements.

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	Year Ended December 31,		
	2001	2000	1999
Revenues:			
Oil and gas	$ 847,022	$ 852,738	$ 644,646
Interest and other	21,778	25,775	89,657
Gain (loss) on disposition of assets, net	7,681	34,184	(24,168)
	876,481	912,697	710,135
Costs and expenses:			
Oil and gas production	209,664	189,265	159,530
Depletion, depreciation and amortization	222,632	214,938	236,047
Impairment of oil and gas properties	-	-	17,894
Exploration and abandonments	127,906	87,550	65,974
General and administrative	36,968	33,262	40,241
Reorganization	-	-	8,534
Interest	131,958	161,952	170,344
Other	39,588	67,231	34,631
	768,716	754,198	733,195
Income (loss) before income taxes and extraordinary items	107,765	158,499	(23,060)
Income tax benefit (provision)	(4,016)	6,000	600
Income (loss) before extraordinary items	103,749	164,499	(22,460)
Extraordinary items - loss on early extinguishment of debt, net of tax	(3,753)	(12,318)	-
Net income (loss)	$ 99,996	$ 152,181	$ (22,460)
Income (loss) per share:			
Basic:			
Income (loss) before extraordinary items	$ 1.05	$ 1.65	$ (.22)
Extraordinary items	(.04)	(.12)	-
Net income (loss)	$ 1.01	$ 1.53	$ (.22)
Diluted:			
Income (loss) before extraordinary items	$ 1.04	$ 1.65	$ (.22)
Extraordinary items	(.04)	(.12)	-
Net income (loss)	$ 1.00	$ 1.53	$ (.22)
Weighted average shares outstanding:			
Basic	98,529	99,378	100,307
Diluted	99,714	99,763	100,307

The accompanying notes are an integral part of these consolidated financial statements.

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands)

	Common Stock	Additional Paid-in Capital	Treasury Stock	Accumulated Deficit	Accumulated Other Comprehensive Income: Deferred Hedge Gains & Losses	Accumulated Other Comprehensive Income: Investment Gains & Losses	Accumulated Other Comprehensive Income: Translation Adjustment	Total Stockholders' Equity
Balance at January 1, 1998	$ 1,008	$ 2,347,996	$ (10,388)	$ (1,552,442)	$ -	$ -	$ 2,903	$ 789,077
Exercise of stock options and employee stock purchases	1	249	-	-	-	-	-	250
Issuance of stock options under long-term incentive plan	-	25	-	-	-	-	-	25
Restricted shares awarded	-	178	4	-	-	-	-	182
Adjustment to dividends	-	-	-	18	-	-	-	18
Realized translation adjustment	-	-	-	-	-	-	(836)	(836)
Net loss	-	-	-	(22,460)	-	-	-	(22,460)
Other comprehensive income:								
Currency translation adjustment	-	-	-	-	-	-	8,358	8,358
Balance at December 31, 1999	1,009	2,348,448	(10,384)	(1,574,884)	-	-	10,425	774,614
Exercise of stock options and employee stock purchases	4	4,160	-	-	-	-	-	4,164
Purchase of treasury stock	-	-	(27,298)	-	-	-	-	(27,298)
Net income	-	-	-	152,181	-	-	-	152,181
Other comprehensive income (loss):								
Unrealized gains on available for sale securities:								
Unrealized holdings gains	-	-	-	-	-	33,828	-	33,828
Gains included in net income	-	-	-	-	-	(25,674)	-	(25,674)
Currency translation adjustment	-	-	-	-	-		(6,910)	(6,910)
Balance at December 31, 2000	1,013	2,352,608	(37,682)	(1,422,703)	-	8,154	3,515	904,905
Common stock issued for partnership acquisitions	57	104,236	-	-	-	-	-	104,293
Exercise of stock options and employee stock purchases	4	5,428	2,708	(636)	-	-	-	7,504
Purchase of treasury stock	-	-	(13,028)	-	-	-	-	(13,028)
Net income	-	-	-	99,996	-	-	-	99,996
Other comprehensive income (loss):								
Deferred hedge gains and losses:								
Transition adjustment	-	-	-	-	(197,444)	-	-	(197,444)
Deferred hedge gains	-	-	-	-	393,004	-	-	393,004
Net losses included in net income	-	-	-	-	5,486	-	-	5,486
Unrealized gains and losses on available for sale securities:								
Unrealized holdings losses	-	-	-	-	-	(45)	-	(45)
Gains included in net income	-	-	-	-	-	(8,109)	-	(8,109)
Currency translation adjustment	-	-	-	-	-	-	(11,173)	(11,173)
Balance at December 31, 2001	$ 1,074	$ 2,462,272	$ (48,002)	$ (1,323,343)	$ 201,046	$ -	$ (7,658)	$ 1,285,389

The accompanying notes are an integral part of these consolidated financial statements.

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2001	2000	1999
Cash flows from operating activities:			
Net income (loss)	$ 99,996	$ 152,181	$ (22,460)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	222,632	214,938	236,047
Impairment of oil and gas properties	-	-	17,894
Exploration expenses, including dry holes	103,595	66,959	50,030
Deferred income taxes	(7,649)	(10,600)	-
(Gain) loss on disposition of assets, net	(7,681)	(34,184)	24,168
Loss on early extinguishment of debt, net of tax	3,753	12,318	-
Other noncash items	29,832	72,475	(866)
Change in operating assets and liabilities, net of effects from acquisitions:			
Accounts receivable	41,295	(7,486)	(7,393)
Inventory	(4,256)	(2,789)	(952)
Other current assets	(6,304)	(9,896)	(2,335)
Accounts payable	(541)	26,260	(18,683)
Interest payable	(733)	2,097	2,851
Other current liabilities	1,661	(52,177)	(23,067)
Net cash provided by operating activities	475,600	430,096	255,234
Cash flows from investing activities:			
Cash acquired in acquisition, net of fees paid	11,119	-	-
Proceeds from disposition of assets	113,453	102,736	390,531
Additions to oil and gas properties	(529,723)	(299,682)	(179,669)
Other property dispositions (additions), net	(17,590)	2,445	(11,867)
Net cash provided by (used in) investing activities	(422,741)	(194,501)	198,995
Cash flows from financing activities:			
Borrowings under long-term debt	328,331	922,607	355,493
Principal payments on long-term debt	(333,410)	(1,099,935)	(793,919)
Payments of other noncurrent liabilities	(53,437)	(29,759)	(34,002)
Purchase of treasury stock	(13,028)	(27,298)	-
Deferred loan fees/issuance costs	-	(13,847)	(6,891)
Exercise of stock options and employee stock purchases	7,504	4,164	250
Net cash used in financing activities	(64,040)	(244,068)	(479,069)
Net decrease in cash and cash equivalents	(11,181)	(8,473)	(24,840)
Effect of exchange rate changes on cash and cash equivalents	(644)	(156)	407
Cash and cash equivalents, beginning of year	26,159	34,788	59,221
Cash and cash equivalents, end of year	$ 14,334	$ 26,159	$ 34,788

The accompanying notes are an integral part of these consolidated financial statements.

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in thousands)

	Year ended December 31,		
	2001	2000	1999
Net income (loss)	$ 99,996	$ 152,181	$ (22,460)
Other comprehensive income:			
Deferred hedge gains and losses:			
Transition adjustment	(197,444)	-	-
Deferred hedge gains	393,004	-	-
Net losses included in net income	5,486	-	-
Gains and losses on available for sale securities:			
Unrealized holding gains and losses	(45)	33,828	-
Gains included in net income	(8,109)	(25,674)	-
Translation adjustment:			
Currency translation adjustment	(11,173)	(6,910)	8,358
Realized translation adjustment	-	-	(836)
Other comprehensive income	181,719	1,244	7,522
Comprehensive income (loss)	$ 281,715	$ 153,425	$ (14,938)

The accompanying notes are an integral part of these consolidated financial statements.

NOTE A. Organization and Nature of Operations

Pioneer Natural Resources Company (the "Company") is a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange and the Toronto Stock Exchange. The Company is an oil and gas exploration and production company with ownership interests in oil and gas properties located principally in the Mid Continent, Southwestern and onshore and offshore Gulf Coast regions of the United States and in Argentina, Canada, South Africa, Gabon and Tunisia.

NOTE B. Summary of Significant Accounting Policies

Principles of consolidation. The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries since their acquisition or formation, and the Company's interest in the affiliated oil and gas partnerships for which it serves as general partner through certain of its wholly-owned subsidiaries. The Company proportionately consolidates less than 100 percent-owned oil and gas partnerships in accordance with industry practice. The Company owns less than a 20 percent interest in the oil and gas partnerships that it proportionately consolidates. All material intercompany balances and transactions have been eliminated.

Investments in non-affiliated equity securities that have a readily determinable fair value are classified as "trading securities" if management's current intent is to hold them for only a short period of time; otherwise, they are accounted for as "available-for-sale" securities. The Company reevaluates the classification of investments in non-affiliated equity securities at each balance sheet date. The carrying value of trading securities and available-for-sale securities are adjusted to fair value as of each balance sheet date.

Unrealized holding gains are recognized for trading securities in interest and other revenue, and unrealized holding losses are recognized in other expense during the periods in which changes in fair value occur. The Company did not have any investments in trading securities as of December 31, 2001 or 2000.

Unrealized holding gains and losses are recognized for available-for-sale securities as credits or charges to stockholders' equity and other comprehensive income (loss) during the periods in which changes in fair value occur. Realized gains and losses on the divestiture of available-for-sale securities are determined using the average cost method. The Company did not have any investments in available-for-sale securities as of December 31, 2001. See Notes C and K below for the fair value and a description of the available-for-sale securities held as of December 31, 2000.

Investments in non-affiliated equity securities that do not have a readily determinable fair value are measured at the lower of their original cost or the net realizable value of the investment. The Company did not have any equity security investments that did not have a readily determinable fair value as of December 31, 2001 or 2000.

Use of estimates in the preparation of financial statements. Preparation of the accompanying consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Depletion of oil and gas properties is determined using estimates of proved oil and gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves; commodity price outlooks; foreign laws, restrictions and currency exchange rates; and export and excise taxes.

Early in January 2002, the Argentine government severed the direct one-to-one U.S. dollar to Argentine peso relationship that has existed for many years. The following bullet points disclose the significant Argentine assumptions utilized in the preparation of the 2001 financial statements:

- As of December 31, 2001, the Company used an exchange rate of 1.7 pesos to $1 to remeasure the peso-denominated monetary assets and liabilities of the Company's Argentine subsidiaries.

- As part of the remeasurement process, the Company generally estimated that the recovery or settlement values to be realized on peso-denominated receivables and payables would be approximately 1.2 pesos to $1.

- After remeasuring inventory at historical exchange rates, the Company reduced the carrying value of its Argentine lease and well equipment to market values. The market value of the inventory was estimated to be 15 percent higher than the historical peso balance, but on an equivalent U.S. dollar basis, lower than the Company's carrying cost.

- The Company reviewed its Argentine proved and unproved properties for impairment as of December 31, 2001. The Company's assessments were based on the Company's expectations of future commodity prices to be received and expenses to be paid in Argentina. The assumptions utilized to determine future net cash flows had oil and natural gas liquids ("NGLs") prices returning to world market prices after a short-term period to allow for price inflation. Similarly, gas prices also were assumed to return to predevaluation U.S. dollar levels after a short-term period to allow for inflation. Expenses were assumed to devalue with the peso, but to gradually increase to 80 percent of predevaluation amounts. Based upon these assumptions, the Company determined that the carrying value of its proved and unproved properties was fully recoverable.

The remeasurement of the peso-denominated monetary net assets and the adjustment to reduce the carrying amount of lease and well equipment inventory to market values resulted in the Company recognizing a $7.7 million charge in 2001. Numerous uncertainties exist surrounding the ultimate resolution of Argentina's economic and political instability and actual results could differ from those estimates and assumptions utilized.

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, (i) the realized prices the Company receives for the commodities it produces and sells as a result of new export taxes or higher production taxes; (ii) the timing of repatriations of excess cash flow to the Company's corporate headquarters in the United States; (iii) the Company's asset valuations; and (iv) peso-denominated monetary assets and liabilities.

Cash equivalents. Cash and cash equivalents include cash on hand and depository accounts held by banks.

Inventories - equipment. Lease and well equipment to be used in future production and drilling activities are carried at the lower of cost or market, on a first-in, first-out basis.

Inventories - commodities. Commodities are carried at the lower of average cost or market. When sold from inventory, commodities are charged to expense on a first-in, first-out basis.

Oil and gas properties. The Company utilizes the successful efforts method of accounting for its oil and gas properties. Under this method, all costs associated with productive wells and nonproductive development wells are capitalized while nonproductive exploration costs and geological and geophysical expenditures are expensed. The Company also expenses the costs associated with exploratory wells that find oil and gas reserves if a determination that proved reserves have been found cannot be made within one year of the exploration well being drilled. The Company capitalizes interest on expenditures for significant development projects until such projects are ready for their intended use.

The Company owns interests in nine natural gas processing plants and four treating facilities. The Company operates six of the plants and all four treating facilities. The Company's ownership in the natural gas processing plants and treating facilities is primarily to accommodate handling the Company's gas production and thus are considered a component of the capital and operating costs of the respective fields that they service. To the extent that there is excess capacity at a plant or treating facility, the Company attempts to process third party gas volumes for a fee to keep the plant or treating facility at capacity. All revenues and expenses derived from third party gas volumes processed through the plants and treating facilities are reported as components of oil and gas production costs. The third party revenues generated from the plant and treating facilities for the three years ended December 31, 2001, 2000 and 1999 were $28.2 million, $36.3 million and $32.7 million, respectively. The third party expenses attributable to the plants and treating facilities for those same periods were $9.2 million, $9.0 million and $9.7 million, respectively. The capitalized costs of the plants and treating facilities are included in proved oil and gas properties and are depleted using the unit-of-production method along with the other capitalized costs of the field that they service.

Capitalized costs relating to proved properties are depleted using the unit-of-production method based on proved reserves as determined by the Company's engineers. Costs of significant nonproducing properties, wells in the process of being drilled and development projects are excluded from depletion until such time as the related project is developed and proved reserves are established or impairment is determined.

Capitalized costs of individual properties sold or abandoned are charged to accumulated depletion, depreciation and amortization with the proceeds from the sales of individual properties credited to property costs. No gain or loss is recognized until the entire amortization base is sold. However, gain or loss is recognized from the sale of less than an entire amortization base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base.

If significant, the Company accrues the estimated future costs to plug and abandon wells under the unit-of-production method. The charge, if any, is reflected in the accompanying Consolidated Statements of Operations as abandonment expense while the liability is reflected in the accompanying Consolidated Balance Sheets as other liabilities. Plugging and abandonment liabilities assumed in a business combination accounted for as a purchase are recorded at fair value. At December 31, 2001 and 2000, the Company has recognized plugging and abandonment liabilities of $39.5 million and $42.0 million, respectively.

The Company reviews its long-lived assets to be held and used, including proved oil and gas properties accounted for under the successful efforts method of accounting, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

Unproved oil and gas properties that are individually significant are periodically assessed for impairment by comparing their cost to their estimated value on a project-by-project basis. The estimated value is affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, the Company will recognize an impairment loss at that time by recording an allowance. The remaining unproved oil and gas properties are aggregated and an overall impairment allowance is provided based on the Company's historical experience.

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

Environmental. The Company's environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Expenditures that extend the life of the related property or mitigate or prevent future environmental contamination are capitalized. Liabilities are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are undiscounted unless the timing of cash payments for the liability are fixed or reliably determinable.

Revenue recognition. The Company uses the entitlements method of accounting for oil, NGL and gas revenues. Sales proceeds in excess of the Company's entitlement are included in other liabilities and the Company's share of sales taken by others is included in other assets in the accompanying Consolidated Balance Sheets. The following table presents the entitlement assets and entitlement liabilities and their associated volumes as of December 31, 2001 and 2000 (in millions):

	December 31,			
	2001		2000	
	Amount	MMcf	Amount	MMcf
Entitlement assets	$ 30.9	25,335	$ 33.7	26,780
Entitlement liabilities	$ 20.3	15,197	$ 19.0	13,830

Stock-based compensation. The Company accounts for employee stock-based compensation using the intrinsic value method prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB 25"). Accordingly, no compensation expense is recognized for stock options granted to employees or directors when the exercise price of options granted is equal to or above the quoted market price of the Company's common stock on the date of grant. The Company has disclosed the pro forma net income (loss) and net income (loss) per share amounts as required by Statement of Financial Accounting Standards No.123, "Accounting for Stock-Based Compensation" ("SFAS 123") in Note F below.

Derivatives and hedging. Prior to January 1, 2001, the following criteria were required to be met in order for the Company to account for a derivative instrument as a hedge of an existing asset or liability, or of a forecasted transaction: an asset, liability or forecasted transaction must have existed that exposed the Company to price, interest rate or foreign exchange rate risk that was not offset in another asset or liability; the derivative instrument must have reduced that price, interest rate or foreign exchange rate risk; and, the derivative instrument must have been designated as a hedge at the inception of the instrument and throughout the hedge period. Additionally, in order to qualify as a hedge, there must have been clear correlation between changes in the fair value or expected cash flows of the derivative instrument and the fair value or expected cash flows of the hedged asset or liability, or forecasted transaction, such that changes in the derivative instrument offset the effect of price, interest rate or foreign exchange rate changes on the exposed items.

Prior to January 1, 2001, gains or losses realized from derivative instruments that qualified as hedges were deferred as assets or liabilities until the underlying hedged asset, liability or transaction monetized, matured or was otherwise recognized under generally accepted accounting principles. When recognized in net income (loss), hedge gains and losses are classified as components of the commodity prices, interest or foreign exchange rates that the derivative instrument hedged. Derivative instruments that are not hedges are recorded at fair value, as assets or liabilities. Changes in the fair values of non-hedge derivative instruments are recognized as other income or other expense during the periods in which their fair values change. See Note H for a description of the specific types of derivative transactions in which the Company participates.

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133") as amended, the provisions of which the Company adopted effective January 1, 2001.

SFAS 133 requires the accounting recognition of all derivative instruments as either assets or liabilities at fair value. Derivative instruments that are not hedges must be adjusted to fair value through net income (loss). Under the provisions of SFAS 133, changes in the fair value of derivative instruments that are fair value hedges are offset against changes in the fair value of the hedged assets, liabilities, or firm commitments, through net income (loss). Effective changes in the fair value of derivative instruments that are cash flow hedges are recognized in other comprehensive income (loss) in stockholders' equity until such time as the hedged items are recognized in net income (loss). Ineffective portions of a derivative instrument's change in fair value are immediately recognized in net income (loss).

The adoption of SFAS 133 resulted in a January 1, 2001 transition adjustment to (i) reclassify $57.8 million of deferred losses on terminated hedge positions from other assets (including $11.6 million of other current assets), (ii) increase other current assets, other assets and other current liabilities by $7.0 million, $6.2 million and $146.6 million, respectively, to record the fair value of open hedge derivatives, (iii) increase the carrying value of hedged long-term debt by $6.2 million and (iv) reduce stockholders' equity by $197.4 million for the net impact of items (i) through (iii) above. The $197.4 million reduction in stockholders' equity was reflected as a transition adjustment in other comprehensive income (loss) as of January 1, 2001.

Under the provisions of SFAS 133, the Company may designate a derivative instrument as hedging the exposure to changes in the fair value of an asset or a liability or an identified portion thereof that is attributable to a particular risk (a "fair value hedge") or as hedging the exposure to variability in expected future cash flows that are attributable to a particular risk (a "cash flow hedge"). Both at the inception of a hedge and on an ongoing basis, a fair value hedge must be expected to be highly effective in achieving offsetting changes in fair value attributable to the hedged risk during the periods that a hedge is designated. Similarly, a cash flow hedge must be expected to be highly effective in achieving offsetting cash flows attributable to the hedged risk during the term of the hedge. The Company's policy is to assess actual hedge effectiveness at the end of each calendar quarter.

Foreign currency translation. The U.S. dollar is the functional currency for all of the Company's international operations except Canada. Accordingly, monetary assets and liabilities denominated in a foreign currency are remeasured to U.S. dollars at the exchange rate in effect at the end of each reporting period; revenues and costs and expenses denominated in a foreign currency are remeasured at the average of the exchange rates that were in effect during the period in which the revenues and costs and expenses were recognized. The resulting gains or losses from remeasuring foreign currency denominated balances into U.S. dollars are recorded in other income or other expense, respectively. Non-monetary assets and liabilities denominated in a foreign currency are remeasured at the historic exchange rates that were in effect when the asset or liabilities were acquired or incurred.

The functional currency of the Company's Canadian operations is the Canadian dollar. The financial statements of the Company's Canadian subsidiary entities are translated to U. S. dollars as follows: all assets and liabilities are translated using the exchange rate in effect at the end of each reporting period; revenues and costs and expenses are translated using the average of the exchange rates that were in effect during the period in which the revenues and costs and expenses were recognized. The resulting gains or losses from translating non-U.S. dollar denominated balances are recorded in the accompanying Consolidated Statements of Stockholders' Equity for the period through accumulated other comprehensive income (loss).

The exchange rates used in the preparation of these consolidated financial statements appear below:

	December 31,		
	2001	2000	1999
Translation:			
U.S. Dollar from Canadian Dollar - Balance Sheets	.6277	.6671	.6915
U.S. Dollar from Canadian Dollar - Statements of Operations	.6356	.6650	.6700

Reclassifications. Certain reclassifications have been made to the 2000 and 1999 amounts to conform to the 2001 presentation.

NOTE C. Disclosures About Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of the Company's financial instruments as of December 31, 2001 and 2000 (in thousands):

	2001		2000	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial assets:				
Investment in non-affiliated entity	$ -	$ -	$ 12,724	$ 12,724
Financial liabilities - long-term debt:				
Practicable to estimate fair value:				
Line of credit	$ 294,000	$ 294,000	$ 225,000	$ 225,000
8-7/8% senior notes due 2005	$ 161,998	$ 159,000	$ 149,546	$ 153,000
8-1/4% senior notes due 2007	$ 153,672	$ 154,215	$ 150,661	$ 148,125
6-1/2% senior notes due 2008	$ 332,613	$ 329,280	$ 348,691	$ 315,000
9-5/8% senior notes due 2010	$ 385,110	$ 421,508	$ 423,577	$ 480,375
7-1/5% senior notes due 2028	$ 249,911	$ 204,175	$ 249,910	$ 193,750
Other	$ -	$ -	$ 31,391	$ -
Derivative contract assets (liabilities):				
Interest rate swaps	$ (19,637)	$ (19,637)	$ -	$ 6,216
Foreign currency contracts	$ 61	$ 61	$ -	$ -
Commodity price hedges	$ 151,290	$ 151,290	$ (52,253)	$ (192,306)
Btu swap contracts	$ (19,422)	$ (19,422)	$ (25,507)	$ (25,507)

Cash and cash equivalents, accounts receivable, other current assets, accounts payable, interest payable and other current liabilities. The carrying amounts approximate fair value due to the short maturity of these instruments.

Investments in non-affiliated entity. As of December 31, 2000, the Company owned 613,215 common shares of Prize Energy Corp. ("Prize") common stock ("Prize Common"). The Prize Common had a fair value of $12.7 million on December 31, 2000, including $8.2 million of unrealized holding gains, and is included in other assets in the accompanying Consolidated Balance Sheet as of December 31, 2000. During 2001, the Company sold its remaining shares of Prize Common (see Note K for additional information regarding the Prize Common divestiture).

Long-term debt. The carrying amount of borrowings outstanding under the Company's corporate credit facility (see Note D) approximates fair value because these instruments bear interest at variable market rates. The fair values of each of the senior note issuances were based on quoted market prices for each of these issues. Other long-term debt was insignificant and no estimate of fair value was performed.

Interest rate swaps, foreign currency swap contracts and commodity price swap and collar contracts. The fair value of interest rate swaps, foreign currency contracts and commodity price swap and collar contracts are estimated from quotes provided by the counterparties to these derivative contracts and represent the estimated amounts that the

Company would expect to receive or pay to settle the derivative contracts. See Note H for a description of each of these derivatives, including whether the derivative contract qualifies for hedge accounting treatment or is considered a speculative derivative contract.

NOTE D. Long-term Debt

Long-term debt, including the effects of fair value hedges and discounts, consisted of the following components at December 31, 2001 and 2000:

	December 31,	
	2001	2000
	(in thousands)	
Line of credit	$ 294,000	$ 225,000
8-7/8% senior notes due 2005	161,998	149,546
8-1/4% senior notes due 2007	153,672	150,661
6-1/2% senior notes due 2008	332,613	348,691
9-5/8% senior notes due 2010	385,110	423,577
7-1/5% senior notes due 2028	249,911	249,910
Other	-	31,391
	$ 1,577,304	$ 1,578,776

Maturities of long-term debt at December 31, 2001 are as follows (in thousands):

2002 through 2004	$ -
2005	$ 455,998
2006	$ -
Thereafter	$ 1,121,306

Line of credit. During May 2000, the Company entered into a $575.0 million corporate credit facility (the "Credit Agreement") with a syndication of banks (the "Banks") that matures on March 1, 2005. Advances under the Credit Agreement bear interest, at the option of the Company, based on (a) a base rate equal to the higher of the Bank of America, N.A. prime rate (4.75 percent at December 31, 2001) or a rate per annum based on the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System (1.52 percent at December 31, 2001), plus 50 basis points; plus a eurodollar margin (the "Eurodollar Margin") less 125 basis points, (b) a Eurodollar rate, substantially equal to the London Interbank Offered Rate ("LIBOR") (1.88 percent at December 31, 2001 for 90 day borrowings), plus a Eurodollar Margin, or (c) a fixed rate (for aggregate advances not exceeding $50 million) as quoted by the Banks pursuant to a request by the Company. The Eurodollar Margin is based on a grid of the Company's debt ratings and ratio of total debt to earnings before gain or loss on the disposition of assets; interest expense; income taxes; depreciation, depletion and amortization expense; exploration and abandonment expense and other noncash expenses (the "Total Leverage Ratio"). As of December 31, 2001, the Eurodollar Margin is 125 basis points.

The Credit Agreement imposes certain restrictive covenants on the Company, including the maintenance of a Total Leverage Ratio not to exceed 4.00 to 1.00 through September 30, 2002 and 3.75 to 1.00 thereafter; maintenance of an annual ratio of the net present value of the Company's oil and gas properties to total debt of at least 1.25 to 1.00; a limitation on the Company's total debt; and, restrictions on certain payments. The Company is in compliance with the debt covenants as of December 31, 2001.

As of December 31, 2001 and 2000, the Company had $27.9 million of undrawn letters of credit issued under the Credit Agreement and unused Credit Agreement borrowing capacity of $253.1 million and $322.1 million, respectively.

Senior notes. The Company's senior notes are general unsecured obligations ranking equally in right of payment with all other senior unsecured indebtedness of the Company and are senior in right of payment to all existing and future subordinated indebtedness of the Company. The Company is a holding company that conducts all of its operations through subsidiaries; consequently, the senior notes issuances are structurally subordinated to all obligations of its subsidiaries. Pioneer Natural Resources USA, Inc. ("Pioneer USA"), a wholly-owned subsidiary, has fully and unconditionally guaranteed the senior note issuances. See Note R for a discussion of Pioneer USA debt guarantees and Consolidating Financial Statements. Interest on the Company's senior notes is payable semiannually.

During April 2000, the Company issued $425.0 million of 9-5/8 percent senior notes Due April 1, 2010 (the "9-5/8 percent senior notes"). The 9-5/8 percent senior notes were issued at a discount of .353 percent and resulted in net proceeds to the Company, after underwriting discounts, commissions and costs of issuance, of $415.4 million. The net proceeds from the issuance of the 9-5/8 percent senior notes were used to reduce outstanding borrowings under the Company's revolving credit facility. The 9-5/8 percent senior notes contain various restrictive covenants, including restrictions on the incurrence of additional indebtedness and certain payments defined within the associated indenture. The Company is in compliance with the debt covenants as of December 31, 2001.

Early extinguishment of debt. During July 2001, the Company redeemed the remaining $22.5 million of outstanding 11-5/8 percent senior subordinated discount notes due July 1, 2006 and $6.8 million of outstanding 10-5/8 percent senior subordinated notes due July 1, 2006. Additionally, during the quarter ended December 31, 2001, the Company redeemed $38.7 million of the 9-5/8 percent senior notes. Associated with these redemptions, the Company recognized an extraordinary loss, net of taxes, of $3.8 million during the year ended December 31, 2001. In May 2000, the Company recognized an extraordinary loss of $12.3 million, net of tax, from the early extinguishment of its prior revolving credit facility.

Interest expense. The following amounts have been charged to interest expense for the years ended December 31, 2001, 2000 and 1999:

	2001	2000	1999
		(in thousands)	
Cash payments for interest	$ 129,992	$ 147,156	$ 150,929
Accretion/amortization of discounts or premiums on loans	7,937	7,995	8,401
Interest capitalized	(5,991)	-	-
Amortization of deferred hedge gains (see Note H)	(2,750)	-	-
Amortization of capitalized loan fees	2,252	2,769	2,686
Kansas ad valorem tax accrual (see Note G)	1,250	1,935	1,433
Net change in accruals	(732)	2,097	6,895
	$ 131,958	$ 161,952	$ 170,344

NOTE E. Related Party Transactions

Activities with affiliated partnerships. The Company, through its wholly-owned subsidiaries, has in the past sponsored certain affiliated partnerships, including 44 drilling partnerships, three public income partnerships and 13 affiliated employee partnerships, all of which were formed primarily for the purpose of drilling and completing wells or acquiring producing properties. In 1992, the Company discontinued sponsoring public and private oil and gas development drilling partnerships, income partnerships and affiliated employee partnerships.

In December 2001, the limited partners of 42 of the Company's affiliated partnerships approved an agreement and plan of merger ("Plan of Merger") among the Company, Pioneer USA and the partnerships. The Plan of Merger was accounted for as a purchase business combination. In consideration for the partnerships' net assets, the limited partners received 5,683,557 shares of the Company's common stock valued at $18.35 per share. In connection with this transaction, the Company acquired net proved reserves of approximately 29 million barrels of oil equivalent, $13.6 million of cash held on deposit by the partnerships and $.3 million of other net assets. The cash acquired from the partnerships, net of $2.5 million of cash transaction costs, is included in cash acquired in acquisitions, net of fees paid in the accompanying Consolidated Statement of Cash Flows for the year ended December 31, 2001. Except for the cash acquired, this transaction represents a noncash investing activity of the Company that was funded by the issuance of common stock.

In December 2000, the Company received the approval of the partners of 13 employee partnerships to merge with Pioneer USA for a purchase price of $2.0 million. Of the total purchase price, $317 thousand was paid to current Company employees. Additionally, during 2000, the Company purchased all of the direct oil and gas interests held by the Company's Chairman of the Board and Chief Executive Officer for $195 thousand.

During each of the years 1994, 1993 and 1992, the Company formed a Direct Investment Partnership for the purpose of permitting selected key employees to invest directly, on an unpromoted basis, in wells that the Company drills. In November 2000, the Company exercised its right under the Direct Investment Partnership agreements to purchase each partner's interest in their respective Direct Investment Partnership. The Company paid $4.3 million to complete the purchase, of which $887 thousand was paid to current Company employees.

The Company, through a wholly-owned subsidiary, serves as operator of properties in which it and its affiliated partnerships have an interest. Accordingly, the Company receives producing well overhead, drilling well overhead and other fees related to the operation of the properties. The affiliated partnerships also reimburse the Company for their allocated share of general and administrative charges.

The activities with affiliated partnerships are summarized for the following related party transactions for the years ended December 31, 2001, 2000 and 1999:

	2001	2000	1999
		(in thousands)	
Receipt of lease operating and supervision charges in accordance with standard industry operating agreements	$ 9,281	$ 9,222	$ 9,059
Reimbursement of general and administrative expenses	$ 1,265	$ 1,550	$ 744

Prize divestiture. The Company sold certain oil and gas properties, gas plants and other assets to Prize during 1999. Associated with these transactions, the Company received $245.0 million of proceeds. During 1999, the board of directors of Prize was partially comprised of Mr. Philip P. Smith, the Chief Executive Officer; Mr. Kenneth A. Hersh; and Mr. Lon C. Kile. Messrs. Smith and Hersh were members of the Board of Directors of the Company and resigned their positions with the Company during the second quarter of 1999. Similarly, Mr. Lon C. Kile resigned his position as Executive Vice President of the Company to accept the position of President and Chief Operating Officer of Prize. The sale of the assets to Prize was initiated through an auction process which, upon receipt of Prize's initial offer, was placed under the supervision of a special independent committee (comprised of outside directors unrelated to Prize) of the Company's Board of Directors. The independent committee reviewed and considered all offers presented to the Company for the purchase of the assets acquired by Prize. The Prize offer was approved by the special independent committee as being the best offer presented (see Note K for additional information regarding the Company's investment in Prize and the divestiture of assets to Prize).

Consulting fee. Effective January 1, 1999, the Company entered into an amended and restated agreement with Rainwater, Inc., whereby the Company pays Rainwater, Inc. $300,000 per year and reimburses Rainwater, Inc. for certain expenses in consideration for certain consulting and financial analysis services provided to the Company by Rainwater, Inc. and its representatives. The term of this agreement expires on December 31, 2003. During 2001, 2000 and 1999, consulting and financial analysis services provided to the Company totaled $300,000, $300,000 and $325,000, respectively, plus expenses. Richard E. Rainwater, who resigned from the Company's Board of Directors during 2000, is the sole shareholder of Rainwater, Inc.

NOTE F. Incentive Plans

Retirement Plans

Deferred compensation retirement plan. In August 1997, the Compensation Committee of the Board of Directors approved a deferred compensation retirement plan for the officers and certain key employees of the Company. Each officer and key employee is allowed to contribute up to 25 percent of their base salary. The Company will then provide a matching contribution of 100 percent of the officer's and key employee's contribution limited to the first 10 percent of the officer's base salary and eight percent of the key employee's base salary. The Company's matching contribution vests immediately. A trust fund has been established by the Company to accumulate the contributions made under this retirement plan. The Company's matching contributions were $652 thousand, $611 thousand and $508 thousand for 2001, 2000 and 1999, respectively.

401(k) plan. The Pioneer Natural Resources USA, Inc. 401(k) Plan (the "401(k) Plan") is a defined contribution plan established under the Internal Revenue Code Section 401. All regular full-time and part-time employees of Pioneer USA are eligible to participate in the 401(k) Plan on the first day of the month following their date of hire. Participants may contribute an amount of not less than two percent nor more than 12 percent of their annual salary into the 401(k) Plan. Each participant's account is credited with the participant's contributions and an allocation of the 401(k) Plan's earnings. Participants are fully vested in their account balances.

Matching plan. The Pioneer Natural Resources USA, Inc. Matching Plan (the "Matching Plan") is a money purchase pension plan which accumulates benefits to participants. All regular full-time and part-time employees of Pioneer USA become eligible to participate in the Matching Plan concurrent with their eligibility to participate in the 401(k) Plan. All Matching Plan contributions are made in cash by Pioneer USA in amounts equal to 200 percent of a participant's contributions to the 401(k) Plan that are not in excess of five percent of the participant's basic compensation (the "Matching Contribution"). Each participant's account is credited with their Matching Contribution and an allocation of Matching Plan earnings. Participants proportionately vest in their account balances over a four year period, at the end of which they are fully vested in their account balances. During the years ended December 31, 2001, 2000 and 1999, the Company recognized compensation expense of $3.4 million, $3.4 million and $3.1 million, respectively, as a result of Matching Contributions.

Long-Term Incentive Plan

In August 1997, the Company's stockholders approved a long-term incentive plan (the "Long-Term Incentive Plan"), which provides for the granting of incentive awards in the form of stock options, stock appreciation rights, performance units and restricted stock to directors, officers and employees of the Company. The Long-Term Incentive Plan provides for the issuance of a maximum number of shares of common stock equal to 10 percent of the total number of shares of common stock equivalents outstanding less the total number of shares of common stock subject to outstanding awards under any stock-based plan for the directors, officers or employees of the Company.

The following table calculates the number of shares or options available for grant under the Company's Long-Term Incentive Plan as of December 31, 2001 and 2000:

	December 31,	
	2001	2000
Shares outstanding	103,936,394	98,415,647
Outstanding exercisable options or exercisable within 60 days	4,658,155	4,355,144
	108,594,549	102,770,791
Maximum shares/options allowed under the Long-Term Incentive Plan	10,859,455	10,277,079
Less: Outstanding awards under Long-Term Incentive Plan	(6,377,520)	(5,514,057)
Outstanding options under predecessor incentive plans	(548,551)	(996,502)
Shares/options available for future grant	3,933,384	3,766,520

Stock option awards. The Company has a program of awarding semi-annual stock options to its officers and employees and gives its non-employee directors a choice to receive stock options or cash as their annual compensation. This program provides for stock option awards at an exercise price based upon the closing sales price of the Company's common stock on the day prior to the date of grant. Employee stock option awards vest over an 18 month or three year schedule and provide a five year exercise period from each vesting date. Non-employee directors' stock options vest quarterly and provide for a five year exercise period from each vesting date. The Company granted 1,627,071, 1,439,035 and 1,945,135 options under the Long-Term Incentive Plan during 2001, 2000 and 1999, respectively.

Restricted stock awards. There were no restricted stock awards to employees or non-employee directors during the years ended December 31, 2001 and 2000. During 1999, the Company awarded an aggregate of 6,200 shares of restricted stock at an average price per share of $29.56.

Other stock based plans. Prior to the formation of the Company in 1997, the Company's predecessor companies had long-term incentive plans in place that allowed the predecessor companies to grant incentive awards similar to the provisions of the Long-Term Incentive Plan. Upon formation of the Company, all awards under these plans were assumed by the Company with the provision that no additional awards be granted under the predecessor plans.

SFAS 123 disclosures. The Company applies APB 25 and related interpretations in accounting for its stock option awards. Accordingly, no compensation expense has been recognized for its stock option awards. If compensation expense for the stock option awards had been determined consistent with SFAS 123, the Company's net income (loss) and net income (loss) per share would have been adjusted to the pro forma amounts indicated below:

	For the Year Ended December 31,		
	2001	2000	1999
	(in thousands, except per share amounts)		
Net income (loss)	$ 93,463	$ 148,018	$ (25,269)
Basic net income (loss) per share	$ .95	$ 1.49	$ (.25)
Diluted net income (loss) per share	$ .94	$ 1.48	$ (.25)

Under SFAS 123, the fair value of each stock option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for grants in 2001, 2000 and 1999:

	For the Year Ended December 31,		
	2001	2000	1999
Risk-free interest rate	4.13%	5.66%	6.59%
Expected life	5 years	5 years	6 years
Expected volatility	49%	50%	48%
Expected dividend yield	-	-	-

A summary of the Company's stock option plans as of December 31, 2001, 2000 and 1999, and changes during the years ended on those dates, are presented below:

	For the Year Ended December 31, 2001		For the Year Ended December 31, 2000		For the Year Ended December 31, 1999	
	Number of Shares	Weighted Average Price	Number of Shares	Weighted Average Price	Number of Shares	Weighted Average Price
Non-statutory stock options:						
Outstanding, beginning of year	6,510,559	$ 18.10	6,241,889	$ 19.45	4,580,030	$ 24.83
Options granted	1,627,071	$ 18.29	1,439,035	$ 10.32	1,945,135	$ 9.10
Options forfeited	(566,189)	$ 25.83	(798,058)	$ 18.05	(256,576)	$ 38.29
Options exercised	(645,370)	$ 11.14	(372,307)	$ 10.78	(26,700)	$ 5.81
Outstanding, end of year	6,926,071	$ 18.16	6,510,559	$ 18.10	6,241,889	$ 19.45
Exercisable at end of year	4,005,762	$ 20.82	3,897,187	$ 23.47	4,038,341	$ 24.62
Weighted average fair value of options granted during the year	$ 8.65		$ 4.88		$ 4.21	

The following table summarizes information about the Company's stock options outstanding at December 31, 2001:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at December 31, 2001	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at December 31, 2001	Weighted Average Exercise Price
$ 5-11	1,224,082	4.9 years	$ 7.93	535,792	$ 8.35
$ 12-18	3,693,822	5.3 years	$ 15.93	1,464,241	$ 14.85
$ 19-26	588,951	3.0 years	$ 23.46	586,513	$ 23.47
$ 27-30	1,327,242	2.1 years	$ 29.59	1,327,242	$ 29.59
$ 31-82	91,974	2.3 years	$ 45.00	91,974	$ 45.00
	6,926,071			4,005,762	

Employee Stock Purchase Plan

The Company has an Employee Stock Purchase Plan (the "ESPP") that allows eligible employees to annually purchase the Company's common stock at a discounted price. Officers of the Company are not eligible to participate in the ESPP. Contributions to the ESPP are limited to 15 percent of an employee's pay (subject to certain ESPP limits) during the nine month offering period. Participants in the ESPP purchase the Company's common stock at a price that is 15 percent below the closing sales price of the Company's common stock on either the first day or the last day of each annual offering period, whichever closing sales price is lower.

NOTE G. Commitments and Contingencies

Severance agreements. The Company has entered into severance agreements with its officers, subsidiary company officers and certain key employees. Salaries and bonuses for the Company's officers are set by the Compensation Committee for the parent company officers and by the Management Committee for subsidiary company officers and key employees. These committees can grant increases or reductions to base salary at their discretion. The current annual salaries for the parent company officers, the subsidiary company officers and key employees covered under such agreements total approximately $16.0 million.

Indemnifications. The Company has indemnified its directors and certain of its officers, employees and agents with respect to claims and damages arising from acts or omissions taken in such capacity, as well as with respect to certain litigation.

Legal actions. The Company is party to various legal actions incidental to its business, including, but not limited to, the proceedings described below. The majority of these lawsuits primarily involve claims for damages arising from oil and gas leases and ownership interest disputes. The Company believes that the ultimate disposition of these legal actions will not have a material adverse effect on the Company's consolidated financial position, liquidity, capital resources or future results of operations. The Company will continue to evaluate its litigation matters on a quarter-by-quarter basis and will adjust its litigation reserves as appropriate to reflect the then current status of litigation.

Masterson. In February 1992, the current lessors of an oil and gas lease (the "Gas Lease") dated April 30, 1955, between R.B. Masterson et al., as lessor, and Colorado Interstate Gas Company ("CIG"), as lessee, sued CIG in Federal District Court in Amarillo, Texas, claiming that CIG had underpaid royalties due under the Gas Lease. Under the agreements with CIG, the Company, as successor to MESA Inc. ("Mesa"), has an entitlement to gas produced from the Gas Lease. In August 1992, CIG filed a third-party complaint against the Company for any such royalty underpayment which may be allocable to the Company. Plaintiffs alleged that the underpayment was the result of CIG's use of an improper gas sales price upon which to calculate royalties and that the proper price should have been determined pursuant to a "favored-nations" clause in a July 1, 1967 amendment to the Gas Lease. The plaintiffs also sought a declaration by the court as to the proper price to be used for calculating future royalties.

The plaintiffs alleged royalty underpayments of approximately $500 million (including interest at 10 percent) dating from July 1, 1967. In March 1995, the court made certain pretrial rulings that eliminated approximately $400 million of the plaintiff's claims (which related to periods prior to October 1, 1989), but which also reduced a number of the Company's defenses. The Company and CIG filed stipulations with the court whereby the Company would have been liable for between 50 percent and 60 percent, depending on the time period covered, of an adverse judgment against CIG for post-February 1988 underpayments of royalties.

On March 22, 1995, a jury trial began and on May 4, 1995, the jury returned its verdict. Among its findings, the jury determined that CIG had underpaid royalties for the period after September 30, 1989, in the amount of approximately $140,000. Although the plaintiffs argued that the "favored-nations" clause entitled them to be paid for all of their gas at the highest price voluntarily paid by CIG to any other lessor, the jury determined that the plaintiffs were estopped from claiming that the "favored-nations" clause provides for other than a pricing-scheme to pricing-scheme comparison. In light of this determination, and the plaintiff's stipulation that a pricing-scheme to pricing-scheme comparison would not result in any "trigger prices" or damages, defendants asked the court for a judgment that plaintiffs take nothing. The court, on June 7, 1995, entered final judgment that plaintiffs recover no monetary damages. The plaintiffs filed a motion for a new trial on June 22, 1995. The court, on July 18, 1997, denied plaintiffs' motion. The plaintiffs appealed to the Fifth Circuit Court of Appeals and on September 8, 2000, the Fifth Circuit Court affirmed the take nothing judgment of the trial court.

On June 7, 1996, the plaintiffs filed a separate suit against CIG and the Company in state court in Amarillo, Texas, similarly claiming underpayment of royalties under the "favored-nations" clause, but based upon the above-described pricing-scheme to pricing-scheme comparison on a well-by-well monthly basis. The plaintiffs also claimed underpayment of royalties since June 7, 1995 under the "favored-nations" clause based upon either the pricing-scheme to pricing-scheme method or their previously alleged higher price method. The Company believed it had several defenses to this action and contested it vigorously.

In January 2002, the Mastersons, CIG and the Company entered into a Settlement Agreement and Lease Amendment. The Lease Amendment, among other things, eliminated the "favored-nations" clause, defined market value at the well, and provided specific relinquishment terms. The facts of the Settlement Agreement were jointly presented to the court and the case was dismissed with prejudices February 1, 2002.

Alford. The Company is party to a 1993 class action lawsuit filed in the 26th Judicial District Court of Stevens County, Kansas by two classes of royalty owners, one for each of the Company's gathering systems connected to the Company's Satanta gas plant. The case was relatively inactive for several years. In early 2000, the plaintiffs amended their pleadings to add claims regarding the field compression installed by the Company in the 1990's. The lawsuit now has two material claims. First, the plaintiffs assert that the expenses related to the field compression are a "cost of production" for which plaintiffs cannot be charged their proportionate share under the applicable oil and gas leases. Second, the plaintiffs claim they are entitled to 100 percent of the value of the helium extracted at the Company's Satanta gas plant. If the plaintiffs were to prevail on the above two claims in their entirety, it is possible that the Company's liability could reach $25 million, plus prejudgment interest. However, the Company believes it has valid defenses to plaintiffs' claims, has paid the plaintiffs properly under their respective oil and gas leases, and intends to vigorously defend itself.

The Company believes the cost of the field compression is not a "cost of production", but is rather an expense of transporting the gas to the Company's Satanta gas plant for processing, where valuable hydrocarbon liquids and helium are extracted from the gas. The plaintiffs benefit from such extractions and the Company believes that charging the plaintiffs with their proportionate share of such transportation and processing expenses is consistent with Kansas law. The Company has also vigorously defended against plaintiffs' claims to 100 percent of the value of the helium extracted, and believes that in accordance with applicable law, it has properly accounted to the plaintiffs for their fractional royalty share of the helium under the specified royalty clauses of the respective oil and gas leases.

The factual evidence in the case was presented to the 26th Judicial District Court without a jury in December 2001. No judgment or findings have been entered, and the court has set the matter for oral arguments in April 2002. Judgment could be entered anytime after April 2002. The Company strongly denies the existence of any material underpayment to plaintiffs and believes it presented strong evidence at trial to support its positions. The Company has not yet determined the amount of damages, if any, that would be payable if the lawsuit was determined adversely to the Company. However, the amount of any resulting liability could have a material adverse effect on the Company's results of operations for the period in which such liability is recorded, but the Company does not expect that any such liability will have a material adverse effect on its consolidated financial position as a whole or on its liquidity, capital resources or future results of operations.

Kansas ad valorem tax. The Natural Gas Policy Act of 1978 ("NGPA") allows a "severance, production or similar" tax to be included as an add-on, over and above the maximum lawful price for gas. Based on a Federal Energy Regulatory Commission ("FERC") ruling that Kansas ad valorem tax was such a tax, Mesa collected the Kansas ad valorem tax in addition to the otherwise maximum lawful price. The FERC's ruling was appealed to the United States Court of Appeals for the District of Columbia ("D.C. Circuit"), which held in June 1988 that the FERC failed to provide a reasoned basis for its findings and remanded the case to the FERC for further consideration.

On December 1, 1993, the FERC issued an order reversing its prior ruling, but limiting the effect of its decision to Kansas ad valorem taxes for sales made on or after June 28, 1988. The FERC clarified the effective date of its decision by an order dated May 18, 1994. The order clarified that the effective date applies to tax bills rendered after June 28, 1988, not sales made on or after that date. Numerous parties filed appeals on the FERC's action in the D.C. Circuit. Various gas producers challenged the FERC's orders on two grounds: (1) that the Kansas ad valorem tax, properly understood, does qualify for reimbursement under the NGPA; and (2) the FERC's ruling should, in any event, have been applied prospectively. Other parties challenged the FERC's orders on the grounds that the FERC's ruling should have been applied retroactively to December 1, 1978, the date of the enactment of the NGPA and producers should have been required to pay refunds accordingly.

The D.C. Circuit issued its decision on August 2, 1996, which holds that producers must make refunds of all Kansas ad valorem tax collected with respect to production since October 4, 1983, as opposed to June 28, 1988. Petitions for rehearing were denied on November 6, 1996. Various gas producers subsequently filed a petition for writ of certiori with the United States Supreme Court seeking to limit the scope of the potential refunds to tax bills rendered on or after June 28, 1988 (the effective date originally selected by the FERC). Williams Natural Gas Company filed a cross-petition for certiori seeking to impose refund liability back to December 1, 1978. Both petitions were denied on May 12, 1997.

The Company and other producers filed petitions for adjustment with the FERC on June 24, 1997. The Company was seeking waiver or set-off from FERC with respect to that portion of the refund associated with (i) non-recoupable royalties, (ii) non-recoupable Kansas property taxes based, in part, upon the higher prices collected, and (iii) interest for all periods. On September 10, 1997, FERC denied this request, and on October 10, 1997, the Company and other producers filed a request for rehearing. Pipelines were given until November 10, 1997 to file claims on refunds sought from producers and refunds totaling approximately $30 million were made against the Company. The Company is unable at this time to predict the final outcome of this matter or the amount, if any, that will ultimately be refunded. As of December 31, 2001 and 2000, the Company had on deposit $24.5 million and $28.1 million, respectively, including accrued interest, in an escrow account and had corresponding obligations for this litigation recorded in other current liabilities in the accompanying Consolidated Balance Sheets. During 2001 and 2000, the Company paid $4.7 million and $3.9 million, respectively, in partial settlement of original claims presented under this litigation.

Lease agreements. The Company leases equipment and office facilities under noncancellable operating leases on which rental expense for the years ended December 31, 2001, 2000 and 1999 was approximately $6.6 million, $7.0 million and $6.9 million, respectively. Future minimum lease commitments under noncancellable operating leases at December 31, 2001, including leases of offshore production facilities, are as follows (in thousands):

2002	$ 5,942
2003	$ 32,067
2004	$ 31,852
2005	$ 29,700
2006	$ 16,530
Thereafter	$ 28,538

NOTE H. Derivative Financial Instruments

Hedge Derivatives

The Company, from time to time, uses derivative instruments to manage interest rate, commodity price and currency exchange rate risks.

Fair value hedging strategy. The Company monitors capital markets and trends to identify opportunities to enter into interest rate swaps to minimize its costs of capital. During April 2000 and May 2001, the Company entered into interest rate swap agreements to hedge the fair value of the Company's 8-7/8 percent Senior Notes due April 15, 2005 and 8-1/4 percent Senior Notes due August 15, 2007, respectively. The terms of the 8-7/8 percent interest rate swap agreements provided for an aggregate notional amount of $150 million of debt; had a scheduled maturity on April 15, 2005; required the counterparties to pay the Company a fixed annual rate of 8-7/8 percent on the notional amount; and, required the Company to pay the counterparties a variable annual rate on the notional amount equal to the periodic three-month LIBOR plus a weighted average margin rate of 178.2 basis points. The terms of the Company's 8-1/4 percent interest rate swap agreements provided for an aggregate notional amount of $150 million of debt; had a scheduled maturity on August 15, 2007; required the counterparties to pay the Company a fixed annual rate of 8-1/4 percent on the notional amount; and, required the Company to pay the counterparties a variable rate on the notional amounts equal to LIBOR plus a weighted average margin rate of 238.1 basis points. On September 21, 2001, the Company terminated its 8-7/8 percent and 8-1/4 percent interest rate swaps for $23.3 million of cash proceeds, including accrued interest. As of December 31, 2001, the carrying value of the senior notes include $18.4 million attributable to the unamortized portion of these deferred hedge gains. The remaining portions of the deferred hedge gains will be amortized as reductions to interest expense over the remaining original terms of the interest rate swaps.

During November 2001, The Company entered into new interest rate swap agreements to hedge the fair value of the Company's 6-1/2 percent Senior Notes due January 15, 2008 and 8-1/4 percent Senior Notes due August 15, 2007, respectively. The terms of the 6-1/2 percent interest rate swap agreements provide for an aggregate notional amount of $350 million of debt; have a scheduled maturity on January 15, 2008; require the counterparties to pay the Company a fixed annual rate of 6-1/2 percent on the notional amount; and, require the Company to pay the counterparties a variable annual rate on the notional amount equal to the periodic six-month LIBOR plus a weighted average margin rate of 202.2 basis points. The terms of the Company's new 8-1/4 percent interest rate swap agreements provide for an aggregate notional amount of $150 million of debt; have a scheduled maturity on August 15, 2007; require the counterparties to pay the Company a fixed annual rate of 8-1/4 percent on the notional amount; and, require the Company to pay the counterparties a variable rate on the notional amounts equal to the periodic six-month LIBOR plus a weighted average margin rate of 337.0 basis points.

The terms of the fair value hedges described above perfectly match the terms of the underlying senior notes. Thus, the Company did not exclude any component of the derivatives' gains or losses from the measurement of hedge effectiveness.

Cash flow hedging strategy. The Company utilizes commodity swap and collar contracts to (i) reduce the effect of price volatility on the commodities the Company produces and sells, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. The Company also utilizes interest rate swap agreements to reduce the effect of interest rate volatility on the Company's variable rate line of credit indebtedness and forward currency exchange agreements to reduce the effect of U.S. dollar to Canadian dollar exchange rate volatility.

Oil. All material sales contracts governing the Company's oil production have been tied directly or indirectly to the New York Mercantile Exchange ("NYMEX") prices. The following table sets forth the Company's outstanding oil hedge contracts and the weighted average NYMEX prices for those contracts as of December 31, 2001:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Yearly Outstanding Average
Daily oil production:					
2002 - Swap Contracts					
Volume (Bbl)	17,000	8,000	8,000	5,000	9,463
Price per Bbl	$ 27.41	$ 26.35	$ 24.76	$ 24.45	$ 26.23
2002 - Collar Contracts					
Volume (Bbl)	6,000	6,000	-	-	2,975
Price per Bbl	$25.00-$28.61	$25.00-$28.61	$ -	$ -	$25.00-$28.61
2003 - Swap Contracts					
Volume (Bbl)	6,000	6,000	-	-	2,975
Price per Bbl	$ 24.02	$ 24.02	$ -	$ -	$ 24.02

The Company reports average oil prices per Bbl including the effects of oil quality, gathering and transportation costs and the net effect of the oil hedges. The following table sets forth the Company's oil prices, both reported (including hedge results) and realized (excluding hedge results), and the net effect of settlements of oil price hedges to revenue:

	Year Ended December 31,		
	2001	2000	1999
Average price reported per Bbl	$ 24.12	$ 24.01	$ 15.36
Average price realized per Bbl	$ 23.88	$ 28.81	$ 16.23
Addition (reduction) to revenue (in millions)	$ 3.0	$ (60.1)	$ (13.4)

Natural gas liquids prices. During the years ended December 31, 2001, 2000 and 1999, the Company did not enter into any NGL hedge contracts.

Gas prices. The Company employs a policy of hedging a portion of its gas production based on the index price upon which the gas is actually sold in order to mitigate the basis risk between NYMEX prices and actual index prices. The following table sets forth the Company's outstanding gas hedge contracts and the weighted average index prices for those contracts as of December 31, 2001:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Yearly Outstanding Average
Daily gas production:					
2002 - Swap Contracts					
Volume (Mcf)	140,000	140,000	190,000	190,000	165,205
Index price per MMBtu	$ 4.28	$ 4.28	$ 4.13	$ 4.14	$ 4.19
2002 - Collar Contracts					
Volume (Mcf)	20,000	20,000	20,000	20,000	20,000
Index price per MMBtu	$4.50-$6.00	$4.50-$6.00	$4.50-$6.00	$4.50-$6.00	$4.50-$6.00
2003 - Swap Contracts					
Volume (Mcf)	117,500	117,500	117,500	117,500	117,500
Index price per MMBtu	$ 3.62	$ 3.62	$ 3.62	$ 3.62	$ 3.62
2004 - Swap Contracts					
Volume (Mcf)	165,000	165,000	165,000	165,000	165,000
Index price per MMBtu	$ 3.84	$ 3.84	$ 3.84	$ 3.84	$ 3.84
2005 - Swap Contracts					
Volume (Mcf)	50,000	50,000	50,000	50,000	50,000
Index price per MMBtu	$ 3.63	$ 3.63	$ 3.63	$ 3.63	$ 3.63

The Company reports average gas prices per Mcf including the effects of Btu content, gathering and transportation costs, gas processing and shrinkage and the net effect of the gas hedges. The following table sets forth the Company's gas prices, both reported (including hedge results) and realized (excluding hedge results), and the net effect of settlements of gas price hedges to revenue:

	Year Ended December 31,		
	2001	2000	1999
Average price reported per Mcf	$ 3.23	$ 2.81	$ 1.90
Average price realized per Mcf	$ 3.20	$ 3.03	$ 1.84
Addition/(reduction) to revenue (in millions)	$ 3.0	$ (29.0)	$ 9.4

Interest rates. During the year ended December 31, 2001, the Company entered into interest rate swap agreements and designated the swap agreements as being cash flow hedges of the interest rate volatility associated with a portion of the Company's variable rate line of credit indebtedness. The terms of the interest rate swap agreements provide for an aggregate notional amount of $55 million of debt; commenced on May 21, 2001 and mature on May 20, 2002; require the counterparties to pay the Company a variable rate equal to the six-month LIBOR plus 125 basis points; and, require the Company to pay the counterparties a weighted average rate of 5.43 percent on the notional amount. The Company recognizes no ineffectiveness associated with changes in the fair values of these derivative instruments.

Foreign currency rates. During the fourth quarter of 2001, the Company entered into forward agreements to exchange an aggregate $24.8 million U.S. dollars during 2002 for Canadian dollars at a weighted average exchange rate of .6266 U.S. dollars for 1.0 Canadian dollar. These agreements are designated as hedges of the exchange rate risk associated with forecasted Canadian sales of gas under U.S. dollar denominated sales agreements. The Company does not expect to recognize any ineffectiveness associated with changes in the fair values of these derivative instruments.

Hedge ineffectiveness and excluded items. During the year ended December 31, 2001, the Company recognized other expense of $9.1 million related to the ineffective portions of its cash flow hedging instruments. Additionally, based on SFAS 133 interpretive guidance that was in effect prior to April 2001, the Company excluded from the measurement of hedge effectiveness changes in the time and volatility value components of collar contracts designated as cash flow hedges. Associated therewith, the Company recorded other expense of $2.4 million during the year ended December 31, 2001. In April 2001, the Company discontinued the exclusion of time value and volatility from the measurement of hedge effectiveness.

Accumulated other comprehensive income - deferred hedge gains and losses, net. As described in Note B, the Company recorded a transition adjustment associated with the January 1, 2001 adoption of the provisions of SFAS 133 which reduced stockholders' equity by $197.4 million. The adjustment to stockholders' equity was comprised of the fair value of the Company's derivative instruments that were designated as commodity cash flow hedges, whose fair value amounted to a liability of $139.6 million as of January 1, 2001, and deferred losses realized from the early termination of cash flow hedges of $57.8 million. These adjustments to stockholders' equity were classified as Accumulated other comprehensive income ("AOCI") - deferred hedge gains and losses at transition. As of December 31, 2001, AOCI - deferred hedge gains and losses represents a net deferred gain of $201.0 million. The AOCI - deferred hedge gains and losses balance as of December 31, 2001 was comprised of $177.7 million of unrealized deferred hedge gains on the effective portions of open commodity, interest rate and forward currency rate cash flow hedges and $23.3 million of net deferred gains on terminated cash flow hedges. The increase in AOCI - deferred hedge gains and losses since January 1, 2001 is primarily attributable to the Company entering into additional oil and gas hedging agreements for future periods, coupled with a decrease in future commodity prices at year end as compared to the commodity prices stipulated in the new and existing hedge agreements. The unrealized deferred hedge gains associated with open cash flow hedges remain subject to market price fluctuations until the position is either settled under the terms of the hedge agreement or terminated prior to settlement. The net deferred gains on terminated cash flow hedges is fixed.

During the twelve month period ending December 31, 2002, the Company expects to reclassify $126.3 million of deferred gains associated with open cash flow hedges and $42.3 million of net deferred losses on terminated cash flow hedges from AOCI - deferred hedge gains and losses to oil and gas revenue. The following table sets forth the scheduled reclassifications of deferred hedge gains and (losses) on terminated cash flow hedges that will be recognized in the Company's future oil and gas revenues:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total Year
			(in thousands)		
2002:					
Oil revenue	$ 2,302	$ 1,640	$ -	$ -	$ 3,942
Gas revenue	(11,390)	(11,516)	(11,643)	(11,643)	(46,192)
	$ (9,088)	$ (9,876)	$(11,643)	$(11,643)	$ (42,250)
2003 gas revenue	$ 12,320	$ 12,300	$ 12,276	$ 12,117	$ 49,013
2004 gas revenue	$ 4,195	$ 4,146	$ 4,137	$ 4,084	$ 16,562

Non-hedge Derivatives

Btu swap agreements. The Company is a party to certain Btu swap agreements that mature at the end of 2004. The Btu swap agreements do not qualify as hedges. The Company has recorded mark-to-market adjustments to decrease the carrying value of the Btu swap liability by $.7 million and $.2 million during the years ended December 31, 2001 and 1999, respectively, and to increase the carrying value of the Btu swap liability by $14.6 million during the year ended December 31, 2000.

During 2001, the Company entered into offsetting Btu swap agreements that have fixed the Company's remaining obligations associated with the Btu swap agreements. The undiscounted future settlement obligations of the Company under the Btu swap agreements are $7.2 million per year for each of 2002, 2003 and 2004.

Foreign currency agreements. Prior to their maturity in 2000, the Company was a party to a series of forward foreign exchange rate swap agreements that exchanged Canadian dollars for U.S. dollars. These contracts did not qualify as hedges. The Company recorded mark-to-market adjustments to increase the carrying value of the foreign exchange swap liabilities by $1.9 million during 2000 and to decrease the carrying value of the foreign exchange swap liabilities by $5.9 million during 1999.

Other non-hedge commodity derivatives. During 1999, the Company sold call options that provided the counterparties an option to exercise calls either on 10,000 Bbls per day of oil, at a strike price of $20.00 per Bbl, or on 100,000 MMBtu per day of gas, at a weighted average strike price of $2.75 per MMBtu. These contracts, which matured during 2000, did not qualify for hedge accounting treatment. The Company recorded mark-to-market adjustments to increase the carrying value of the contract liability by $42.0 million and $21.2 million during the years ended December 31, 2000 and 1999, respectively.

NOTE I. Major Customers and Derivative Counterparties

Sales to major customers. The Company's share of oil and gas production is sold to various purchasers. The Company is of the opinion that the loss of any one purchaser would not have an adverse effect on the ability of the Company to sell its oil and gas production.

The following customers individually accounted for 10 percent or more of the consolidated oil, NGL and gas revenues of the Company during the years ended December 31, 2001, 2000 and 1999:

	Percentage of Consolidated Oil, NGL and Gas Revenues		
	2001	2000	1999
Williams Energy Services	11	13	11
Anadarko Petroleum Corporation	10	6	5

At December 31, 2001, the amounts receivable from Williams Energy Services and Anadarko Petroleum Corporation were $9.0 million and $8.0 million, respectively, which are included in the caption "Accounts receivable - trade" in the accompanying Consolidated Balance Sheet.

Derivative counterparties. The Company uses credit and other financial criteria to evaluate the credit standing of, and to select, counterparties to its derivative instruments. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative instruments, associated credit risk is mitigated by the Company's credit risk policies and procedures. As of December 31, 2001, the Company has $7.8 million of derivative assets for which Enron North America Corp is the Company's counterparty. Associated therewith, the Company recognized a $6.0 million bad debt expense during the fourth quarter of 2001, which is included in other expense in the accompanying Consolidated Statement of Operations for the year ended December 31, 2001.

NOTE J. Interest and Other Income

The Company recorded interest and other income of $21.8 million, $25.8 million and $89.7 million during the years ended December 31, 2001, 2000 and 1999. The major categories of the Company's interest and other income are summarized in the following table:

	Year Ended December 31,		
	2001	2000 (in thousands)	1999
Purchase option fees (a)	$ -	$ -	$ 41,808
Excise tax income (b)	4,126	6,915	30,200
Production payment income	5,552	1,262	670
Interest income	2,128	3,906	2,145
Seismic data sales	1,841	1,148	79
Foreign exchange gains	223	220	2,629
Other income	7,908	12,324	12,126
	$ 21,778	$ 25,775	$ 89,657

(a) In December 1998, the Company announced the sale of an exclusive and irrevocable option to purchase certain oil and gas properties of the Company. The option holder was unable to complete the purchase and the option expired unexecuted on March 31, 1999. In payment for the option and related liquidated damages, the option holder paid the Company $41.8 million, which was recorded as other income in 1999.

(b) During 1999, the Company received an excise tax refund of $30.2 million which had not previously been recognized as an asset, due to uncertainties surrounding the collectability of the refund. Accordingly, the Company recognized the tax refund as other income during 1999.

NOTE K. Asset Divestitures

During the years ended December 31, 2001, 2000 and 1999, the Company completed asset divestitures for net proceeds of $113.5 million, $102.7 million and $420.5 million (of which $390.5 million in 1999 was cash proceeds), respectively. Associated therewith, the Company recorded gains on disposition of assets of $7.7 million and $34.2 million during the years ended December 31, 2001 and 2000, and a loss on disposition of assets of $24.2 million during the year ended December 31, 1999.

Prize divestitures. On June 29, 1999, the Company completed a sale of certain United States oil and gas producing properties, gas plants and other assets to Prize. The oil and gas producing assets sold to Prize included properties located in the United States Gulf Coast, Mid Continent and Permian Basin areas.

In accordance with the terms of the purchase and sale agreement (the "Prize Divestiture"), the Company received net sales proceeds of $245.0 million, comprised of $215.0 million of cash and 2,307.693 shares of Prize Preferred having a 1999 liquidation preference and fair value of $30.0 million. During 1999, the Company recognized a loss of $46.4 million from the Prize Divestiture. Prior to February 9, 2000, Prize was a closely held, non-public entity and the fair market value of the Prize Preferred was not readily determinable. On February 9, 2000, Prize Common began to publicly trade on the American Stock Exchange. At that time, the Company's Prize Preferred was exchanged for 3,984,197 shares of Prize Series A 6% Convertible Preferred Stock ("Prize Senior A Preferred"). On March 31, 2000, the Company and Prize converted the Company's 3,984,197 shares of Prize Senior A Preferred to 3,984,197 shares of Prize Common, received cash in lieu of 33,964 shares of preferred in-kind dividends and sold to Prize 1,346,482 shares of the Prize Common for a combined cash total of $18.6 million. During 2000, the Company sold an additional 2,024,500 shares of Prize Common in the open market for $41.1 million, recording an associated gain on disposition of assets of $34.3 million. During 2001, the Company sold its remaining 613,250 shares of Prize Common for $12.7 million of cash proceeds and recognized an associated gain on disposition of assets of $8.1 million. The cash proceeds provided from the sale of the Prize Common are included in proceeds from disposition of assets in the accompanying Consolidated Statements of Cash Flows for the years ended December 31, 2001 and 2000.

Other United States divestitures. During the year ended December 31, 2001, the Company received $81.6 million of proceeds, representing deferred hedge gains, from the early termination of derivatives that are designated as hedges of United States interest rate and commodity price risks. See Note H for information regarding the Company's derivative instruments and deferred hedge gains and losses.

During the year ended December 31, 2000, the Company sold an office building in Midland, Texas, certain other assets and non-strategic oil and gas properties primarily located in the United States Gulf Coast and Mid Continent areas. Associated with these divestitures, the Company realized net divestment proceeds of $43.0 million and recorded a net loss on disposition of assets of $.4 million. In addition to the Prize Divestiture, the Company completed 1999 divestitures of non-strategic United States oil and gas properties located in the South Texas Gulf Coast, West Texas Permian Basin and North Dakota areas, an East Texas gas facility and certain other assets for net cash proceeds of $116.2 million during 1999, resulting in net gains on divestitures of assets of $31.0 million.

International divestitures. During the year ended December 31, 2001, the Company received $3.8 million of proceeds, representing deferred hedge gains that will be recorded as increments to 2003 gas revenues, from the early termination of derivatives that are designated as hedges of 2003 Canadian gas price risk. During 2001, the Company also received $12.0 million of proceeds from the sale of certain oil properties in Canada and $.4 million of proceeds from the sale of other international assets. Associated with these transactions, the Company recognized a net loss of $.8 million on disposition of these assets. During 1999, the Company completed the divestitures of certain non-strategic Canadian oil and gas properties, gas plants and other related assets. In accordance with the terms of the Canadian divestitures, the Company received net cash proceeds of $59.3 million and recognized a net loss of $8.8 million.

NOTE L. Impairment of Long-Lived Assets

During the year ended December 31, 1999, the Company assessed its unproved oil and gas properties for impairment and, based thereon, recognized an unproved property impairment provision of $17.9 million. The unproved property impairment provision recognized during 1999 reduced the carrying value of certain East Texas gas properties.

PIONEER NATURAL RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2001, 2000 and 1999

NOTE M. Reorganization

During 1998, the Company announced the reorganization of its domestic operations by combining six domestic operating regions, as well as other cost reduction initiatives intended to allow the Company to realize greater operational and administrative efficiencies. Specific cost reduction initiatives included the relocation of most of the Company's administrative services from Midland, Texas to Irving, Texas; the closings of the Company's regional offices in Oklahoma City, Oklahoma, Corpus Christi, Texas and Houston, Texas; and the termination of 350 employees. The consolidation of administrative services to Irving and the closing of the Corpus Christi, Texas office were completed in 1998. The Company completed the closings of the Houston, Texas and Oklahoma City, Oklahoma offices during 1999 and further centralized certain operational functions in Irving, Texas. As a result of these reorganization initiatives, the Company recognized reorganization charges of $8.5 million during 1999.

The following table provides a description of the components of the reorganization charges and unpaid portions of the charges as of December 31, 2001, 2000 and 1999. The unpaid office closing amount at December 31, 2001 relates to a lease commitment on an office building in Oklahoma City, Oklahoma.

	Total Charges	Payments (in thousands)	Unpaid Portion as of December 31,
2001:			
Office closings	$ -	$ 326	$ 156
2000:			
Office closings	$ -	$ 1,155	$ 482
Relocation	-	230	-
	$ -	$ 1,385	$ 482
1999:			
Employee terminations	$ 3,125	$ 7,805	$ -
Office closings	340	2,233	1,637
Relocation	4,998	4,768	230
Other	71	71	-
	$ 8,534	$ 14,877	$ 1,867

NOTE N. Other Expense

The following table provides the components of the Company's other expense during the years ended December 31, 2001, 2000 and 1999:

	Years Ended December 31, 2001	2000 (in thousands)	1999
Derivative ineffectiveness and mark-to-market provisions (see Note H)	$ 11,458	$ 58,518	$ 15,089
Trading security mark-to-market provisions (a)	-	-	11,875
Gas marketing losses (b)	9,850	-	-
Foreign currency remeasurement and exchange losses (c)	8,474	80	175
Bad debt expense (recovery) (see Note I)	6,152	65	(729)
Other charges	3,654	8,568	8,221
	$ 39,588	$ 67,231	$ 34,631

(a) During 1999, the Company owned four million shares of common stock of a non-affiliated public entity for trading purposes. Prior to the disposition of the shares in 1999, the Company recognized an $11.9 million decline in the fair value of the investment as a charge to other expense.

(b) The Company's Canadian operations periodically purchase third party gas volumes for transport to and resale at a Chicago sales point. Associated therewith, the Company recognized $9.9 million of gas marketing losses in other expenses during 2001.

(c) The Company's operations in Argentina, Canada and Africa periodically recognize monetary assets and liabilities in currencies other than their functional currencies (see Note B for information regarding the functional currencies of subsidiary entities). Associated therewith, the Company realizes foreign currency remeasurement and transaction gains and losses. In early January 2002, the Argentine government severed the one-to-one relationship between the value of the Argentine peso and the U.S. dollar, which is the functional currency of the Company's Argentine operations. Consequently, the Company remeasured the peso denominated monetary net assets and adjusted the lease and well equipment inventory balances to market values which resulted in a charge of $7.7 million in 2001.

NOTE O. Income Taxes

The Company accounts for income taxes in accordance with the provisions of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes". The Company and its eligible subsidiaries file a consolidated United States federal income tax return. Certain subsidiaries are not eligible to be included in the consolidated United States federal income tax return and separate provisions for income taxes have been determined for these entities or groups of entities. The tax returns and the amount of taxable income or loss are subject to examination by United States federal, state and foreign taxing authorities. Current and estimated tax payments of $11.7 million, $4.6 million and $800 thousand were made in 2001, 2000 and 1999, respectively. In addition, the Company received an income tax refund of $1.4 million in 1999. During 2001, 2000 and 1999, the Company's income tax provision (benefit) and amounts separately allocated were attributable to the following items:

	Year Ended December 31,		
	2001	2000	1999
		(in thousands)	
Income (loss) before extraordinary item	$ 4,016	$ (6,000)	$ (600)
Changes in other comprehensive income:			
Deferred hedge gains and losses	2,293	-	-
Cumulative translation adjustment	(121)	(200)	1,600
	$ 6,188	$ (6,200)	$ 1,000

Income tax provision (benefit) attributable to income (loss) before extraordinary item consists of the following:

	Year Ended December 31,		
	2001	2000	1999
		(in thousands)	
Current:			
U.S. state and local	$ 1,080	$ -	$ 400
Foreign	10,585	4,600	(1,000)
	11,665	4,600	(600)
Deferred:			
U.S. federal	-	-	14,700
Foreign	(7,649)	(10,600)	(14,700)
	(7,649)	(10,600)	-
Total	$ 4,016	$ (6,000)	$ (600)

Income (loss) before income taxes and extraordinary item consists of the following:

	Year Ended December 31,		
	2001	2000	1999
		(in thousands)	
Income (loss) before income taxes and extraordinary item:			
U.S. federal	$ 140,045	$ 138,941	$ (23,594)
Foreign	(32,280)	19,558	534
	$ 107,765	$ 158,499	$ (23,060)

Reconciliations of the United States federal statutory rate to the Company's effective rate for income (loss) before extraordinary item are as follows:

	2001	2000	1999
U.S. federal statutory tax rate	35.0	35.0	(35.0)
Valuation allowance	(27.5)	(30.9)	102.0
Rate differential on foreign operations	(3.2)	(2.9)	(68.1)
Other	(.6)	(5.0)	(1.5)
Consolidated effective tax rate	3.7	(3.8)	(2.6)

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

	December 31,	
	2001	2000
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 341,206	$ 350,916
Alternative minimum tax credit carryforwards	1,565	1,565
Other	106,365	105,792
Total deferred tax assets	449,136	458,273
Valuation allowance	(244,742)	(283,400)
Net deferred tax assets	204,394	174,873
Deferred tax liabilities:		
Oil and gas properties, principally due to differences in basis and depletion and the deduction of intangible drilling costs for tax purposes	115,524	82,551
Other	11,919	31,622
Total deferred tax liabilities	127,443	114,173
Net deferred tax asset	$ 76,951	$ 60,700

Realization of deferred tax assets associated with net operating loss carryforwards ("NOLs") and other credit carryforwards is dependent upon generating sufficient taxable income prior to their expiration. The Company believes that there is a risk that certain of these NOLs and other credit carryforwards may expire unused and, accordingly, has established a valuation allowance of $244.7 million against them. Although realization is not assured for the remaining deferred tax asset, the Company believes it is more likely than not that they will be realized through future taxable earnings or alternative tax planning strategies. However, the net deferred tax assets could be reduced further if the Company's estimate of taxable income in future periods is significantly reduced or alternative tax planning strategies are no longer viable.

At December 31, 2001, the Company had NOLs for United States, Canadian, South African and Tunisian income tax purposes of $881.8 million, $40.6 million, $39.2 million and $4.6 million, respectively, which are available to offset future regular taxable income in each respective tax jurisdiction, if any. Additionally, at December 31, 2001, the

Company has alternative minimum tax net operating loss carryforwards ("AMT NOLs") in the United States of $766.8 million, which are available to reduce future alternative minimum taxable income, if any. These carryforwards expire as follows:

	U.S.		Canada	South Africa	Tunisia
Expiration Date	NOL	AMT NOL	NOL	NOL	NOL
			(in thousands)		
December 31, 2002	$ 5,109	$ 2,695	$ -	$ -	$ -
December 31, 2003	838	-	-	-	-
December 31, 2005	11,049	10,762	34,822	-	-
December 31, 2006	30,834	12,254	5,738	-	-
December 31, 2007	104,107	101,151	-	-	-
December 31, 2008	112,508	106,558	-	-	-
December 31, 2009	129,227	102,727	-	-	-
December 31, 2010	124,859	110,961	-	-	-
December 31, 2011	6,521	4,045	-	-	-
December 31, 2012	68,542	58,930	-	-	-
December 31, 2018	127,925	98,559	-	-	-
December 31, 2019	145,999	144,836	-	-	-
December 31, 2020	14,235	13,296	-	-	-
Indefinite	-	-	-	39,161	4,569
Total	$ 881,753	$ 766,774	$ 40,560	$ 39,161	$ 4,569

The Company believes $180.0 million of the NOLs and AMT NOLs are subject to Section 382 of the Internal Revenue Code and are limited in each taxable year to approximately $20.0 million.

NOTE P. Geographic Operating Segment Information

The Company has operations in only one industry segment, that being the oil and gas exploration and production industry; however, the Company is organizationally structured along geographic operating segments, or regions. The Company has reportable operations in the United States, Argentina and Canada. Other foreign is primarily comprised of operations in South Africa, Gabon and Tunisia.

The following table provides the geographic operating segment data required by Statement of Financial Accounting Standards No. 131, "Disclosure about Segments of an Enterprise and Related Information", as well as results of operations of oil and gas producing activities required by Statement of Financial Accounting Standards No. 69, "Disclosures about Oil and Gas Producing Activities". Geographic operating segment income tax benefits (provisions) have been determined based on statutory rates existing in the various tax jurisdictions where the Company has oil and gas producing activities. The "Headquarters and Other" table column includes revenues, expenses, additions to properties, plants and equipment and assets that are not routinely included in the earnings measures or attributes internally reported to management on a geographic operating segment basis.

	United States	Argentina	Canada	Other Foreign	Headquarters and Other	Consolidated Total
			(in thousands)			
Year Ended December 31, 2001:						
Oil and gas revenues	$ 649,635	$ 130,241	$ 67,146	$ -	$ -	$ 847,022
Interest and other	-	-	-	-	21,778	21,778
Gain (loss) on disposition of assets	224	-	(1,339)	-	8,796	7,681
	649,859	130,241	65,807	-	30,574	876,481
Production costs	170,578	26,614	12,472	-	-	209,664
Depletion, depreciation and amortization	128,477	51,391	28,868	-	13,896	222,632
Exploration and abandonments	70,049	23,857	9,882	24,118	-	127,906
General and administrative	-	-	-	-	36,968	36,968
Interest	-	-	-	-	131,958	131,958
Other	-	-	-	-	39,588	39,588
	369,104	101,862	51,222	24,118	222,410	768,716
Income (loss) before income taxes and extraordinary items	280,755	28,379	14,585	(24,118)	(191,836)	107,765
Income tax benefit (provision)	(98,264)	(9,933)	(6,216)	8,441	101,956	(4,016)
Income (loss) before extraordinary items	$ 182,491	$ 18,446	$ 8,369	$ (15,677)	$ (89,880)	$ 103,749
Cost incurred for long-lived assets	$ 454,229	$ 98,311	$ 36,048	$ 57,972	$ -	$ 646,560
Segment assets (as of December 31)	$ 2,212,540	$ 710,702	$ 187,841	$ 53,314	$ 106,656	$ 3,271,053
Year Ended December 31, 2000:						
Oil and gas revenues	$ 649,273	$ 140,990	$ 62,475	$ -	$ -	$ 852,738
Interest and other	-	-	-	-	25,775	25,775
Gain on disposition of assets	4,690	-	335	-	29,159	34,184
	653,963	140,990	62,810	-	54,934	912,697
Production costs	155,075	24,417	9,773	-	-	189,265
Depletion, depreciation and amortization	121,932	52,141	25,132	-	15,733	214,938
Exploration and abandonments	40,867	25,388	5,131	16,164	-	87,550
General and administrative	-	-	-	-	33,262	33,262
Interest	-	-	-	-	161,952	161,952
Other	-	-	-	-	67,231	67,231
	317,874	101,946	40,036	16,164	278,178	754,198
Income (loss) before income taxes and extraordinary item	336,089	39,044	22,774	(16,164)	(223,244)	158,499
Income tax benefit (provision)	(117,631)	(13,665)	(10,162)	5,657	141,801	6,000
Income (loss) before extraordinary item	$ 218,458	$ 25,379	$ 12,612	$ (10,507)	$ (81,443)	$ 164,499
Cost incurred for long-lived assets	$ 204,122	$ 68,430	$ 43,591	$ 23,597	$ -	$ 339,740
Segment assets (as of December 31)	$ 1,899,633	$ 702,868	$ 227,250	$ 16,552	$ 108,132	$ 2,954,435
Year Ended December 31, 1999:						
Oil and gas revenues	$ 502,585	$ 83,697	$ 58,364	$ -	$ -	$ 644,646
Interest and other	-	-	-	-	89,657	89,657
Loss on disposition of assets	(14,736)	-	(8,836)	-	(596)	(24,168)
	487,849	83,697	49,528	-	89,061	710,135
Production costs	124,654	18,268	16,608	-	-	159,530
Depletion, depreciation and amortization	153,775	38,874	25,601	-	17,797	236,047
Impairment of oil and gas properties	17,894	-	-	-	-	17,894
Exploration and abandonments	41,225	14,009	3,509	7,231	-	65,974
General and administrative	-	-	-	-	40,241	40,241
Reorganization	-	-	-	-	8,534	8,534
Interest	-	-	-	-	170,344	170,344
Other	-	-	-	-	34,631	34,631
	337,548	71,151	45,718	7,231	271,547	733,195
Income (loss) before income taxes	150,301	12,546	3,810	(7,231)	(182,486)	(23,060)
Income tax benefit (provision)	(52,605)	(4,140)	(1,699)	2,531	56,513	600
Net income (loss)	$ 97,696	$ 8,406	$ 2,111	$ (4,700)	$ (125,973)	$ (22,460)
Cost incurred for long-lived assets	$ 105,663	$ 76,654	$ 11,552	$ 7,257	$ -	$ 201,126
Segment assets (as of December 31)	$ 1,865,441	$ 734,382	$ 218,526	$ 8,289	$ 102,835	$ 2,929,473

NOTE Q. Income (Loss) Per Share Before Extraordinary Items

Basic income (loss) per share before extraordinary items is computed by dividing income (loss) before extraordinary items by the weighted average number of common shares outstanding for the period. The computation of diluted income (loss) per share before extraordinary items reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock or resulted in the issuance of common stock that would then share in the earnings of the entity.

The following table is a reconciliation of the basic and diluted income (loss) per share before extraordinary items computations for the years ended December 31, 2001, 2000 and 1999:

	Year Ended December 31,		
	2001	2000	1999
	(in thousands, except per share amounts)		
Basic and diluted income (loss) before extraordinary items	$ 103,749	$ 164,499	$ (22,460)
Weighted average common shares outstanding:			
Basic	98,529	99,378	100,307
Dilutive common stock options (a)	1,185	385	-
Diluted	99,714	99,763	100,307
Income (loss) per share before extraordinary items:			
Basic	$ 1.05	$ 1.65	$ (.22)
Diluted	$ 1.04	$ 1.65	$ (.22)

(a) Common stock options to purchase 3,595,880 shares, 4,911,749 shares and 5,274,964 shares of common stock were outstanding but not included in the computations of diluted net income (loss) per share for 2001, 2000 and 1999, respectively, because the exercise prices of the options were greater than the average market price of the common shares and would be anti-dilutive to the computations. In-the-money options representing 158,556 weighted average equivalent shares of common stock were not included in the computation of diluted net loss per share for 1999, since they have a dilutive effect to the period's net loss.

NOTE R. Pioneer USA

Pioneer USA is a wholly-owned subsidiary of the Company that has fully and unconditionally guaranteed certain debt securities of the Company (see Note D above). The Company has not prepared financial statements and related disclosures for Pioneer USA under separate cover because management of the Company has determined that such information is not material to investors. In accordance with practices accepted by the United States Securities and Exchange Commission, the Company has prepared Consolidating Condensed Financial Statements in order to quantify the assets of Pioneer USA as a subsidiary guarantor. The following Consolidating Condensed Balance Sheets as of December 31, 2001 and 2000, and Consolidating Statements of Operations and Comprehensive Income (Loss) and Consolidating Condensed Statements of Cash Flows for the years ended December 31, 2001, 2000 and 1999 present financial information for Pioneer Natural Resources Company as the Parent on a stand-alone basis (carrying any investments in subsidiaries under the equity method), financial information for Pioneer USA on a stand-alone basis (carrying any investment in non-guarantor subsidiaries under the equity method), financial information for the non-guarantor subsidiaries of the Company on a consolidated basis, the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis, and the financial information for the Company on a consolidated basis. Pioneer USA is not restricted from making distributions to the Company.

PIONEER NATURAL RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2001, 2000 and 1999

CONSOLIDATING CONDENSED BALANCE SHEET
As of December 31, 2001

	Pioneer Natural Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries (in thousands)	Eliminations	The Company
ASSETS					
Current assets:					
Cash and cash equivalents	$ 79	$ 10,900	$ 3,355	$	$ 14,334
Other current assets	1,540,985	(1,125,968)	(173,708)		241,309
Total current assets	1,541,064	(1,115,068)	(170,353)		255,643
Property, plant and equipment, at cost:					
Oil and gas properties, using the successful efforts method of accounting:					
Proved properties	-	2,688,962	1,002,821		3,691,783
Unproved properties	-	25,222	162,563		187,785
Accumulated depletion, depreciation and amortization	-	(815,323)	(279,987)		(1,095,310)
	-	1,898,861	885,397		2,784,258
Deferred income taxes	82,811	-	1,508		84,319
Other property and equipment, net	-	17,881	3,679		21,560
Other assets, net	15,911	81,356	28,006		125,273
Investment in subsidiaries	1,060,457	87,636	-	(1,148,093)	-
	$ 2,700,243	$ 970,666	$ 748,237		$ 3,271,053
LIABILITIES AND STOCKHOLDERS' EQUITY					
Total current liabilities	$ 30,745	$ 176,442	$ 21,022	$	$ 228,209
Long-term debt, less current maturities	1,577,304	-	-		1,577,304
Other noncurrent liabilities	19,582	124,552	22,249		166,383
Deferred income taxes	-	-	13,768		13,768
Stockholders' equity	1,072,612	669,672	691,198	(1,148,093)	1,285,389
Commitments and contingencies	-	-	-		-
	$ 2,700,243	$ 970,666	$ 748,237		$ 3,271,053

CONSOLIDATING CONDENSED BALANCE SHEET
As of December 31, 2000

	Pioneer Natural Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries (in thousands)	Eliminations	The Company
ASSETS					
Current assets:					
Cash and cash equivalents	$ 15	$ 18,387	$ 7,757	$	$ 26,159
Other current assets	2,006,496	(1,245,546)	(595,718)		165,232
Total current assets	2,006,511	(1,227,159)	(587,961)		191,391
Property, plant and equipment, at cost:					
Oil and gas properties, using the successful efforts method of accounting:					
Proved properties	-	2,291,872	896,017		3,187,889
Unproved properties	-	28,103	201,102		229,205
Accumulated depletion, depreciation and amortization	-	(692,250)	(209,889)		(902,139)
	-	1,627,725	887,230		2,514,955
Deferred income taxes	84,400	-	-		84,400
Other property and equipment, net	-	20,823	4,801		25,624
Other assets, net	18,877	89,632	29,556		138,065
Investment in subsidiaries	347,370	100,192	-	(447,562)	-
	$ 2,457,158	$ 611,213	$ 333,626		$ 2,954,435
LIABILITIES AND STOCKHOLDERS' EQUITY					
Total current liabilities	$ 37,889	$ 140,415	$ 38,210	$	$ 216,514
Long-term debt, less current maturities	1,578,776	-	-		1,578,776
Other noncurrent liabilities	-	190,476	35,264		225,740
Deferred income taxes	-	-	28,500		28,500
Stockholders' equity	840,493	280,322	231,652	(447,562)	904,905
Commitments and contingencies					
	$ 2,457,158	$ 611,213	$ 333,626		$ 2,954,435

PIONEER NATURAL RESOURCES COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2001, 2000 and 1999

CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME
For the Year Ended December 31, 2001
(in thousands)

	Pioneer Natural Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries	Consolidated Income Tax Provision	Eliminations	The Company
Revenues:						
Oil and gas	$ -	$ 626,964	$ 220,058	$ -	$	$ 847,022
Interest and other	368	14,415	6,995	-		21,778
Gain (loss) on disposition of assets, net	-	8,524	(843)	-		7,681
	368	649,903	226,210	-		876,481
Costs and expenses:						
Oil and gas production	-	168,287	41,377	-		209,664
Depletion, depreciation and amortization	-	135,838	86,794	-		222,632
Exploration and abandonments	-	73,649	54,257	-		127,906
General and administrative	804	25,476	10,688	-		36,968
Interest	31,261	83,473	17,224	-		131,958
Equity (income) loss from subsidiary	(135,459)	5,588	-	-	129,871	-
Other	-	9,247	30,341	-		39,588
	(103,394)	501,558	240,681	-		768,716
Income (loss) before income taxes	103,762	148,345	(14,471)	-		107,765
Income tax provision	-	(783)	(3,220)	(13)		(4,016)
Income (loss) before extraordinary items	103,762	147,562	(17,691)	(13)		103,749
Extraordinary items - loss on early extinguishment of debt	(3,753)	-	-	-		(3,753)
Net income (loss)	100,009	147,562	(17,691)	(13)		99,996
Other comprehensive income:						
Deferred hedge gains and losses:						
Transition adjustment	-	(172,007)	(25,437)	-		(197,444)
Deferred hedge gains (losses)	(578)	364,051	29,531	-		393,004
Net (gains) losses included in net income	135	(8,595)	13,946	-		5,486
Gains and losses on available for sale securities:						
Unrealized holdings losses	-	(45)	-	-		(45)
Gains included in net income	-	(8,109)	-	-		(8,109)
Translation adjustment	-	-	(11,173)	-		(11,173)
Comprehensive income	$ 99,566	$ 322,857	$ (10,824)	$ (13)		$ 281,715

CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME
For the Year Ended December 31, 2000
(in thousands)

	Pioneer Natural Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries	Consolidated Income Tax Provision	Eliminations	The Company
Revenues:						
Oil and gas	$ -	$ 616,030	$ 236,708	$ -	$	$ 852,738
Interest and other	29	13,808	11,938	-		25,775
Gain (loss) on disposition of assets, net	(6,172)	36,946	3,410	-		34,184
	(6,143)	666,784	252,056	-		912,697
Costs and expenses:						
Oil and gas production	-	150,281	38,984	-		189,265
Depletion, depreciation and amortization	-	129,996	84,942	-		214,938
Exploration and abandonments	-	43,938	43,612	-		87,550
General and administrative	283	22,519	10,460	-		33,262
Interest	(53,180)	151,026	64,106	-		161,952
Equity (income) loss from subsidiary	(117,704)	(6,313)	-	-	124,017	-
Other	-	63,459	3,772	-		67,231
	(170,601)	554,906	245,876	-		754,198
Income before income taxes	164,458	111,878	6,180	-		158,499
Income tax benefit (provision)	-	(4)	5,963	41		6,000
Income before extraordinary item	164,458	111,874	12,143	41		164,499
Extraordinary item - loss on early extinguishment of debt	(12,318)	-	-	-		(12,318)
Net income	152,140	111,874	12,143	41		152,181
Other comprehensive income (loss):						
Unrealized gains on available for sale securities:						
Unrealized holdings gains	-	33,828	-	-		33,828
Gains included in net income	-	(25,674)	-	-		(25,674)
Translation adjustment	-	-	(6,910)	-		(6,910)
Comprehensive income	$ 152,140	$ 120,028	$ 5,233	$ 41		$ 153,425

PIONEER NATURAL RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2001, 2000 and 1999

CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS AND COMPREHENSIVE LOSS
For the Year Ended December 31, 1999
(in thousands)

	Pioneer Natural Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries	Consolidated Income Tax Provision	Eliminations	The Company
Revenues:						
Oil and gas	$ -	$ 470,059	$ 174,587	$ -	$	$ 644,646
Interest and other	406	52,232	37,019	-		89,657
Gain (loss) on disposition of assets, net	-	19,379	(43,547)	-		(24,168)
	406	541,670	168,059	-		710,135
Costs and expenses:						
Oil and gas production	-	120,074	39,456	-		159,530
Depletion, depreciation and amortization	-	157,294	78,753	-		236,047
Impairment of oil and gas properties	-	17,894	-	-		17,894
Exploration and abandonments	-	43,133	22,841	-		65,974
General and administrative	1,051	27,260	11,930	-		40,241
Reorganization	-	8,534	-	-		8,534
Interest	(33,404)	145,184	58,564	-		170,344
Equity income (loss) from subsidiary	39,672	(5,179)	-	-	(34,493)	-
Other	799	38,166	(4,334)	-		34,631
	8,118	552,360	207,210	-		733,195
Loss before income taxes	(7,712)	(10,690)	(39,151)	-		(23,060)
Income tax benefit (provision)	-	(444)	15,792	(14,748)		600
Net loss	(7,712)	(11,134)	(23,359)	(14,748)		(22,460)
Other comprehensive income:						
Translation adjustment	-	-	8,358	-		8,358
Comprehensive loss	$ (7,712)	$ (11,134)	$ (15,001)	$ (14,748)		$ (14,102)

CONSOLIDATING CONDENSED STATEMENT OF CASH FLOWS
For the Year Ended December 31, 2001
(in thousands)

	Pioneer Natural Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries	The Company
Cash flows from operating activities:				
Net cash provided by (used in) operating activities	$ (10,503)	$ 307,776	$ 178,327	$ 475,600
Cash flows from investing activities:				
Cash acquired in acquisition, net of fees paid	-	11,119	-	11,119
Proceeds from disposition of assets	21,170	75,816	16,467	113,453
Additions to oil and gas properties	-	(336,753)	(192,970)	(529,723)
Other property additions, net	-	(10,717)	(6,873)	(17,590)
Net cash provided by (used in) investing activities	21,170	(260,535)	(183,376)	(422,741)
Cash flows from financing activities:				
Borrowings under long-term debt	328,331	-	-	328,331
Principal payments on long-term debt	(333,410)	-	-	(333,410)
(Payments of) borrowings under noncurrent liabilities	-	(54,728)	1,291	(53,437)
Purchase of treasury stock	(13,028)	-	-	(13,028)
Exercise of stock options and employee stock purchases	7,504	-	-	7,504
Net cash provided by (used in) financing activities	(10,603)	(54,728)	1,291	(64,040)
Net increase (decrease) in cash and cash equivalents	64	(7,487)	(3,758)	(11,181)
Effect of exchange rate changes on cash and cash equivalents	-	-	(644)	(644)
Cash and cash equivalents, beginning of period	15	18,387	7,757	26,159
Cash and cash equivalents, end of period	$ 79	$ 10,900	$ 3,355	$ 14,334

CONSOLIDATING CONDENSED STATEMENT OF CASH FLOWS
For the Year Ended December 31, 2000
(in thousands)

	Pioneer Natural Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries	The Company
Cash flows from operating activities:				
Net cash provided by operating activities	$ 213,491	$ 118,300	$ 98,305	$ 430,096
Cash flows from investing activities:				
Proceeds from disposition of assets	-	92,342	10,394	102,736
Additions to oil and gas properties	-	(179,861)	(119,821)	(299,682)
Other property (additions) dispositions, net	-	(10,004)	12,449	2,445
Net cash used in investing activities	-	(97,523)	(96,978)	(194,501)
Cash flows from financing activities:				
Borrowings under long-term debt	922,607	-	-	922,607
Principal payments on long-term debt	(1,099,107)	(828)	-	(1,099,935)
Payment of noncurrent liabilities	-	(24,261)	(5,498)	(29,759)
Purchase of treasury stock	(27,298)	-	-	(27,298)
Deferred loan fees/issuance costs	(13,847)	-	-	(13,847)
Exercise of stock options and employee stock purchases	4,164	-	-	4,164
Net cash used in financing activities	(213,481)	(25,089)	(5,498)	(244,068)
Net increase (decrease) in cash and cash equivalents	10	(4,312)	(4,171)	(8,473)
Effect of exchange rate changes on cash and cash equivalents	-	-	(156)	(156)
Cash and cash equivalents, beginning of period	5	22,699	12,084	34,788
Cash and cash equivalents, end of period	$ 15	$ 18,387	$ 7,757	$ 26,159

CONSOLIDATING CONDENSED STATEMENT OF CASH FLOWS
For the Year Ended December 31, 1999
(in thousands)

	Pioneer Natural Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries	The Company
Cash flows from operating activities:				
Net cash provided by (used in) operating activities	$ 152,485	$ (230,625)	$ 333,374	$ 255,234
Cash flows from investing activities:				
Proceeds from disposition of assets	-	328,182	62,349	390,531
Additions to oil and gas properties	-	(74,257)	(105,412)	(179,669)
Other property additions, net	-	(8,335)	(3,532)	(11,867)
Net cash provided by (used in) investing activities	-	245,590	(46,595)	198,995
Cash flows from financing activities:				
Borrowings under long-term debt	355,493	-	-	355,493
Principal payments on long-term debt	(504,493)	(1,192)	(288,234)	(793,919)
Payment of noncurrent liabilities	-	(29,006)	(4,996)	(34,002)
Deferred loan fees/issuance costs	(6,891)	-	-	(6,891)
Exercise of stock options and employee stock purchases	250	-	-	250
Net cash used in financing activities	(155,641)	(30,198)	(293,230)	(479,069)
Net decrease in cash and cash equivalents	(3,156)	(15,233)	(6,451)	(24,840)
Effect of exchange rate changes on cash and cash equivalents	-	-	407	407
Cash and cash equivalents, beginning of period	3,161	37,932	18,128	59,221
Cash and cash equivalents, end of period	$ 5	$ 22,699	$ 12,084	$ 34,788

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2001, 2000 and 1999

Capitalized Costs

	December 31, 2001	December 31, 2000
	(in thousands)	
Oil and Gas Properties:		
Proved	$ 3,691,783	$ 3,187,889
Unproved	187,785	229,205
	3,879,568	3,417,094
Less accumulated depletion	(1,095,310)	(902,139)
Net capitalized costs for oil and gas properties	$ 2,784,258	$ 2,514,955

Costs Incurred for Oil and Gas Producing Activities

	Property Acquisition Costs Proved	Property Acquisition Costs Unproved	Exploration Costs	Development Costs	Total Costs Incurred
			(in thousands)		
Year Ended December 31, 2001:					
United States	$ 132,793	$ 19,572	$ 129,639	$ 172,225	$ 454,229
Argentina	13,182	2,465	36,237	46,427	98,311
Canada	29	97	12,707	23,215	36,048
South Africa	706	125	21,936	13,860	36,627
Other foreign (a)	-	1,835	19,510	-	21,345
Total costs incurred	$ 146,710	$ 24,094	$ 220,029	$ 255,727	$ 646,560
Year Ended December 31, 2000:					
United States	$ 26,102	$ 28,199	$ 65,023	$ 84,798	$ 204,122
Argentina	1,169	520	35,406	31,335	68,430
Canada	8,709	2,506	6,744	25,632	43,591
South Africa	-	-	20,176	-	20,176
Other foreign (b)	-	-	3,421	-	3,421
Total costs incurred	$ 35,980	$ 31,225	$ 130,770	$ 141,765	$ 339,740
Year Ended December 31, 1999:					
United States	$ 937	$ 3,185	$ 42,337	$ 59,204	$ 105,663
Argentina	36,312	2,517	12,597	25,228	76,654
Canada	174	(7,375)	1,431	17,322	11,552
South Africa	-	-	2,178	-	2,178
Other foreign (b)	151	-	4,928	-	5,079
Total costs incurred	$ 37,574	$ (1,673)	$ 63,471	$ 101,754	$ 201,126

(a) Primarily comprised of costs to drill an exploratory well in Gabon and one in Tunisia as well as additional geological and geophysical costs in both areas.

(b) Primarily comprised of geological and geophysical costs in Gabon.

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2001, 2000 and 1999

Results of Operations

Information about the Company's results of operations for oil and gas producing activities is presented in Note P of the accompanying Notes to Consolidated Financial Statements.

Reserve Quantity Information

The estimates of the Company's proved oil and gas reserves, which are located principally in the United States, Argentina, Canada and South Africa, are prepared by the Company's engineers. Reserves were estimated in accordance with guidelines established by the SEC and the Financial Accounting Standards Board, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements. The reserve estimates for 2001, 2000 and 1999 utilize respective oil prices of $18.88, $25.71 and $24.33 per Bbl (reflecting adjustments for oil quality and gathering and transportation costs); respective NGL prices of $11.58, $16.74 and $17.59 per Bbl; and, respective gas prices of $2.21, $7.50 and $1.83 per Mcf (reflecting adjustments for Btu content, gathering and transportation costs and gas processing and shrinkage).

Oil and gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2001, 2000 and 1999

Oil and Gas Producing Activities:

	2001			2000			1999		
Total Proved Reserves:	**Oil & NGLs (MBBLS)**	**Gas (MMCF)**	**MBOE**	**Oil & NGLs (MBBLS)**	**Gas (MMCF)**	**MBOE**	**Oil & NGLs (MBBLS)**	**Gas (MMCF)**	**MBOE**
UNITED STATES									
Balance, January 1	266,802	1,354,327	492,523	259,066	1,314,842	478,206	269,638	1,545,644	527,246
Revisions of previous estimates:									
Related to price changes	(18,022)	(50,385)	(26,419)	10,972	29,055	15,814	70,536	99,604	87,137
Other	16,843	91,424	32,080	8,323	34,857	14,133	(18,887)	97,229	(2,682)
Purchases of minerals-in-place	24,943	63,113	35,462	1,237	28,071	5,916	-	-	-
New discoveries and extensions	4,442	93,220	19,979	4,819	66,486	15,900	149	1,351	374
Production	(15,862)	(77,609)	(28,796)	(16,872)	(83,930)	(30,860)	(20,163)	(106,095)	(37,845)
Sales of minerals-in-place	-	-	-	(743)	(35,054)	(6,586)	(42,207)	(322,891)	(96,024)
Balance, December 31	279,146	1,474,090	524,829	266,802	1,354,327	492,523	259,066	1,314,842	478,206
ARGENTINA									
Balance, January 1	35,843	408,282	103,890	29,797	415,620	99,067	24,219	428,334	95,608
Revisions of previous estimates:									
Related to price changes	-	-	-	-	-	-	-	-	-
Other	(932)	4,460	(189)	1,411	(15,558)	(1,182)	(2,441)	(12,470)	(4,520)
Purchases of minerals-in-place	170	31,700	5,453	-	-	-	4,406	17,483	7,320
New discoveries and extensions	4,354	58,538	14,110	8,066	43,914	15,385	6,182	16,750	8,974
Production	(3,766)	(31,830)	(9,071)	(3,431)	(35,694)	(9,380)	(2,569)	(34,477)	(8,315)
Balance, December 31	35,669	471,150	114,193	35,843	408,282	103,890	29,797	415,620	99,067
CANADA									
Balance, January 1	4,066	132,919	26,219	3,970	145,251	28,179	12,447	249,230	53,985
Revisions of previous estimates:									
Related to price changes	(1)	8,701	1,449	(119)	(10,116)	(1,805)	169	(1,113)	(18)
Other	213	6,366	1,274	548	103	565	4,696	(61,243)	(5,509)
Purchases of minerals-in-place	-	-	-	140	7,768	1,435	-	-	-
New discoveries and extensions	81	5,644	1,022	138	6,132	1,160	-	-	-
Production	(671)	(18,426)	(3,742)	(611)	(16,219)	(3,315)	(1,960)	(17,886)	(4,941)
Sales of minerals-in-place	(1,029)	(3,143)	(1,553)	-	-	-	(11,382)	(23,737)	(15,338)
Balance, December 31	2,659	132,061	24,669	4,066	132,919	26,219	3,970	145,251	28,179
SOUTH AFRICA									
Balance, January 1	5,552	-	5,552	-	-	-	-	-	-
Purchases of minerals-in-place	2,133	-	2,133	-	-	-	-	-	-
New discoveries and extensions	-	-	-	5,552	-	5,552	-	-	-
Balance, December 31	7,685	-	7,685	5,552	-	5,552	-	-	-
TOTAL									
Balance, January 1	312,263	1,895,528	628,184	292,833	1,875,713	605,452	306,304	2,223,208	676,839
Revisions of previous estimates:									
Related to price changes	(18,023)	(41,684)	(24,970)	10,853	18,939	14,009	70,705	98,491	87,119
Other	16,124	102,250	33,165	10,282	19,402	13,516	(16,632)	23,516	(12,711)
Purchases of minerals-in-place	27,246	94,813	43,048	1,377	35,839	7,351	4,406	17,483	7,320
New discoveries and extensions	8,877	157,402	35,111	18,575	116,532	37,997	6,331	18,101	9,348
Production	(20,299)	(127,865)	(41,609)	(20,914)	(135,843)	(43,555)	(24,692)	(158,458)	(51,101)
Sales of minerals-in-place	(1,029)	(3,143)	(1,553)	(743)	(35,054)	(6,586)	(53,589)	(346,628)	(111,362)
Balance, December 31	325,159	2,077,301	671,376	312,263	1,895,528	628,184	292,833	1,875,713	605,452
Proved Developed Reserves:									
United States	206,922	1,081,592	387,188	209,636	1,118,976	396,133	240,588	1,422,430	477,659
Argentina	22,679	345,281	80,226	22,931	358,124	82,618	22,172	368,940	83,662
Canada	2,930	80,953	16,422	2,598	61,210	12,800	12,193	210,405	47,261
January 1	232,531	1,507,826	483,836	235,165	1,538,310	491,551	274,953	2,001,775	608,582
United States	196,893	1,027,750	368,184	206,922	1,081,592	387,188	209,636	1,118,976	396,133
Argentina	28,248	341,967	85,243	22,679	345,281	80,226	22,931	358,124	82,618
Canada	2,086	94,607	17,854	2,930	80,953	16,422	2,598	61,210	12,800
December 31	227,227	1,464,324	471,281	232,531	1,507,826	483,836	235,165	1,538,310	491,551

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2001, 2000 and 1999

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is computed by applying year-end prices of oil and gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and gas reserves less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and gas properties plus available carryforwards and credits and applying the current tax rates to the difference. The discounted future net cash flows estimated in the table below do not include the effects of the Company's commodity hedging contracts. Utilizing December 31, 2001 commodity prices held constant over each hedge contract's term, the net present value of the Company's hedge contracts discounted at 10 percent was an asset equal to approximately $230 million.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of oil and gas properties. Estimates of fair value should also consider probable reserves, anticipated future oil and gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is necessarily subjective and imprecise.

	For the Year Ended December 31,		
	2001	2000	1999
		(in thousands)	
UNITED STATES			
Oil and gas producing activities:			
Future cash inflows	$ 8,222,573	$ 18,660,169	$ 8,143,587
Future production costs	(3,231,730)	(4,907,134)	(2,823,316)
Future development costs	(735,984)	(479,290)	(288,801)
Future income tax expense	(598,612)	(3,777,157)	(855,875)
	3,656,247	9,496,588	4,175,595
10% annual discount factor	(1,691,118)	(4,780,133)	(1,837,826)
Standardized measure of discounted future cash flows	$ 1,965,129	$ 4,716,455	$ 2,337,769
ARGENTINA			
Oil and gas producing activities:			
Future cash inflows	$ 1,070,664	$ 1,183,652	$ 1,075,904
Future production costs	(227,435)	(215,853)	(199,513)
Future development costs	(144,604)	(114,606)	(79,336)
Future income tax expense	(45,140)	(81,705)	(87,274)
	653,485	771,488	709,781
10% annual discount factor	(262,334)	(264,126)	(240,681)
Standardized measure of discounted future cash flows	$ 391,151	$ 507,362	$ 469,100
CANADA			
Oil and gas producing activities:			
Future cash inflows	$ 301,002	$ 1,029,007	$ 354,662
Future production costs	(73,601)	(104,189)	(91,913)
Future development costs	(27,050)	(35,443)	(54,571)
Future income tax expense	(10,771)	(306,399)	(2,522)
	189,580	582,976	205,656
10% annual discount factor	(59,995)	(168,441)	(75,266)
Standardized measure of discounted future cash flows	$ 129,585	$ 414,535	$ 130,390
SOUTH AFRICA			
Oil and gas producing activities:			
Future cash inflows	$ 149,777	$ 126,134	$ -
Future production costs	(73,697)	(65,232)	-
Future development costs	(54,281)	(47,970)	-
Future income tax expense	-	-	-
	21,799	12,932	-
10% annual discount factor	(7,338)	(5,782)	-
Standardized measure of discounted future cash flows	$ 14,461	$ 7,150	$ -
TOTAL			
Oil and gas producing activities:			
Future cash inflows	$ 9,744,016	$ 20,998,962	$ 9,574,153
Future production costs	(3,606,463)	(5,292,408)	(3,114,742)
Future development costs	(961,919)	(677,309)	(422,708)
Future income tax expense	(654,523)	(4,165,261)	(945,671)
	4,521,111	10,863,984	5,091,032
10% annual discount factor	(2,020,785)	(5,218,482)	(2,153,773)
Standardized measure of discounted future cash flows	$ 2,500,326	$ 5,645,502	$ 2,937,259

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2001, 2000 and 1999

Oil and Gas Producing Activities

	For the Year Ended December 31, 2001	2000	1999
		(in thousands)	
Oil and gas sales, net of production costs	$ (631,365)	$ (663,473)	$ (485,116)
Net changes in prices and production costs	(4,528,168)	3,829,794	1,571,584
Extensions and discoveries	184,454	525,361	60,695
Development costs incurred during the period	239,156	101,350	84,526
Sales of minerals-in-place	(23,372)	(72,624)	(468,376)
Purchases of minerals-in-place	201,535	187,097	56,309
Revisions of estimated future development costs	(429,365)	(200,734)	(199,569)
Revisions of previous quantity estimates	40,771	344,454	387,616
Accretion of discount	701,943	293,726	164,881
Changes in production rates, timing and other	(274,689)	(262,784)	115,901
Change in present value of future net revenues	(4,519,100)	4,082,167	1,288,451
Net change in present value of future income taxes	1,373,924	(1,373,924)	-
	(3,145,176)	2,708,243	1,288,451
Balance, beginning of year	5,645,502	2,937,259	1,648,808
Balance, end of year	$ 2,500,326	$ 5,645,502	$ 2,937,259

Selected Quarterly Financial Results

	Quarter First	Second	Third	Fourth
		(in thousands, except per share data)		
2001				
Operating revenues	$ 257,986	$ 218,611	$ 198,088	$ 172,337
Total revenues	$ 270,446	$ 231,038	$ 204,471	$ 170,526
Costs and expenses	$ 202,127	$ 200,092	$ 178,864	$ 187,633
Net income (loss):				
Before extraordinary items	$ 67,919	$ 28,338	$ 23,228	$ (15,736)
Extraordinary items, net of tax (a)	-	-	1,374	(5,127)
Net income (loss)	$ 67,919	$ 28,338	$ 24,602	$ (20,863)
Net income (loss) per share:				
Basic:				
Before extraordinary items	$ .69	$ .29	$ .24	$ (.16)
Extraordinary items	-	-	.01	(.05)
Net income (loss)	$ .69	$ .29	$ .25	$ (.21)
Diluted:				
Before extraordinary items	$ .68	$ .28	$ .24	$ (.16)
Extraordinary items	-	-	.01	(.05)
Net income (loss)	$ .68	$ .28	$ .25	$ (.21)
2000				
Operating revenues	$ 174,375	$ 197,947	$ 228,587	$ 251,829
Total revenues	$ 186,502	$ 198,354	$ 257,945	$ 269,896
Costs and expenses	$ 172,032	$ 203,697	$ 192,557	$ 185,912
Net income (loss):				
Before extraordinary item	$ 14,770	$ (3,743)	$ 69,288	$ 84,184
Extraordinary item, net of tax (a)	-	(12,318)	-	-
Net income (loss)	$ 14,770	$ (16,061)	$ 69,288	$ 84,184
Net income (loss) per share:				
Basic:				
Before extraordinary item	$ .15	$ (.04)	$ .70	$ .86
Extraordinary item	-	(.12)	-	-
Net income (loss)	$ .15	$ (.16)	$ .70	$ .86
Diluted:				
Before extraordinary item	$ .15	$ (.04)	$ .69	$ .85
Extraordinary item	-	(.12)	-	-
Net income (loss)	$ .15	$ (.16)	$ .69	$ .85

(a) During July 2001, the Company redeemed the remaining $22.5 million of outstanding 11-5/8 percent senior subordinated discount notes due July 1, 2006 and $6.8 million of outstanding 10-5/8 percent senior subordinated notes due July 1, 2006 and recognized an extraordinary gain, net of taxes, of $1.3 million associated with these redemptions. Additionally, during the quarter ended December 31, 2001, the Company redeemed $38.7 million of the 9-5/8 percent senior notes and recognized an extraordinary loss, net of taxes, of $5.1 million associated with this redemption. As a result of the early extinguishment of a revolving credit facility, the Company recognized an extraordinary loss of $12.3 million, net of taxes, during May 2000 (see Note D of the accompanying Notes to Consolidated Financial Statements).

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on May 14, 2002 and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on May 14, 2002 and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on May 14, 2002 and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on May 14, 2002 and is incorporated herein by reference.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) Listing of Financial Statements and Exhibits

Financial Statements

The following consolidated financial statements of the Company are included in "Item 8. Financial Statements and Supplementary Data":

Independent Auditors' Report
Consolidated Balance Sheets as of December 31, 2001 and 2000
Consolidated Statements of Operations for the years ended December 31, 2001, 2000 and 1999
Consolidated Statements of Stockholders' Equity for the years ended December 31, 2001, 2000 and 1999
Consolidated Statements of Cash Flows for the years ended December 31, 2001, 2000 and 1999
Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2001, 2000 and 1999
Notes to Consolidated Financial Statements
Unaudited Supplementary Information

All other statements and schedules for which provision is made in the applicable accounting regulations of the SEC have been omitted because they are not required under related instructions or are inapplicable, or the information is shown in the financial statements and related notes.

(b) Reports on Form 8-K

During the three months ended December 31, 2001, the Company did not file any current reports on Form 8-K.

(c) Exhibits

Included in Form 10-K filed with the Securities and Exchange Commission.

(d) Financial Statement Schedules

No financial statement schedules are required to be filed as part of this Report or they are inapplicable.

SHAREHOLDER INFORMATION

Stock Exchange Listing–Common Stock
Ticker symbol: PXD
New York Stock Exchange
Toronto Stock Exchange

Corporate Headquarters
Pioneer Natural Resources Company
5205 N. O'Connor Blvd., Suite 1400
Irving, TX 75039
(972) 444-9001

Internet Address
www.pioneernrc.com

Stock Transfer Agent and Registrar
Communication concerning the transfer or exchange of shares, lost certificates or change of address should be directed to:

Continental Stock Transfer
& Trust Company
17 Battery Place, 8th Floor
New York, NY 10004
(888) 509-5586
www.continentalstock.com
pioneer@continentalstock.com

Information Requests
To receive additional copies of the Annual Report on Form 10-K as filed with the Securities and Exchange Commission, to obtain other Pioneer publications or to be placed on the direct mailing list please contact:

Pioneer Natural Resources Company
Investor Relations
5205 N. O'Connor Blvd., Suite 1400
Irving, TX 75039
(972) 969-3583
ir@pioneernrc.com

Investor Relations / Media Contact
Shareholders, portfolio managers, brokers and securities analysts seeking information concerning Pioneer's operations or financial condition are encouraged to contact Susan Spratlen, Vice President, Investor Relations and Communication at (972) 444-9001.

BOARD OF DIRECTORS

Scott D. Sheffield
Chairman, President and
Chief Executive Officer

James R. Baroffio[1]
Former President
Chevron Canada Resources

Edison C. Buchanan[2]
Former Managing Director
Credit Suisse First Boston

R. Hartwell Gardner[3]
Retired Treasurer
Mobil Corporation

James L. Houghton[3]
Retired Senior Tax Partner
Ernst & Young L.L.P. (Accounting Firm)

Jerry P. Jones[3]
Retired Shareholder and Of Counsel
Thompson & Knight, P.C. (Law Firm)

Linda K. Lawson[4]
Former Vice President
Williams Companies

Charles E. Ramsey, Jr.[1]
Financial Consultant
(Petroleum Management)

Robert A. Solberg[4]
Retired Vice President
Texaco, Inc.

Committee Membership:
[1] Compensation Committee
[2] Nominee Standing for Election May 14, 2002
[3] Audit Committee
[4] Newly Elected By Board Effective May 14, 2002

CORPORATE OFFICERS

Scott D. Sheffield
Chairman, President and
Chief Executive Officer

Chris J. Cheatwood
Executive Vice President,
Worldwide Exploration

Timothy L. Dove
Executive Vice President
and Chief Financial Officer

Dennis E. Fagerstone
Executive Vice President,
International Operations

Danny L. Kellum
Executive Vice President,
Domestic Operations

Mark L. Withrow
Executive Vice President,
General Counsel and Secretary

A. R. Alameddine
Vice President, Worldwide
Business Development

Richard P. Dealy
Vice President and
Chief Accounting Officer

Thomas C. Halbouty
Vice President and
Chief Information Officer

Larry N. Paulsen
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