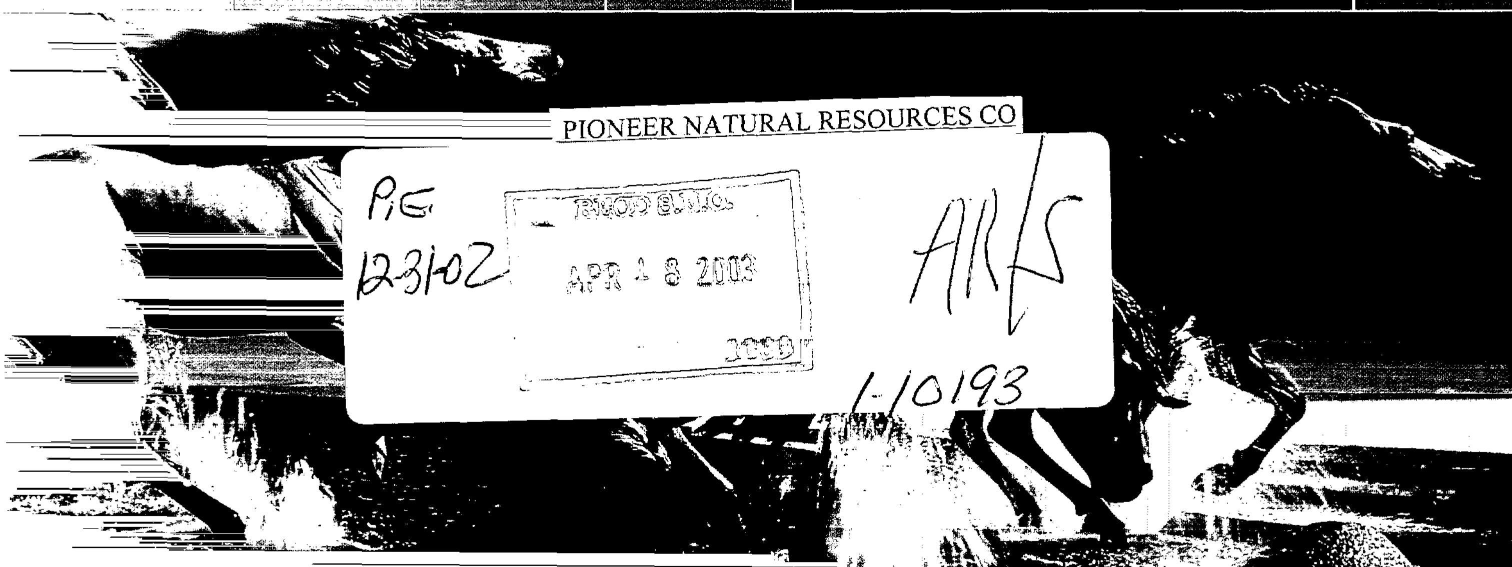
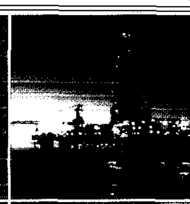
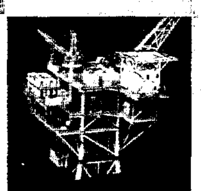
PIONEER
NATURAL RESOURCES







Hitting Our Stride

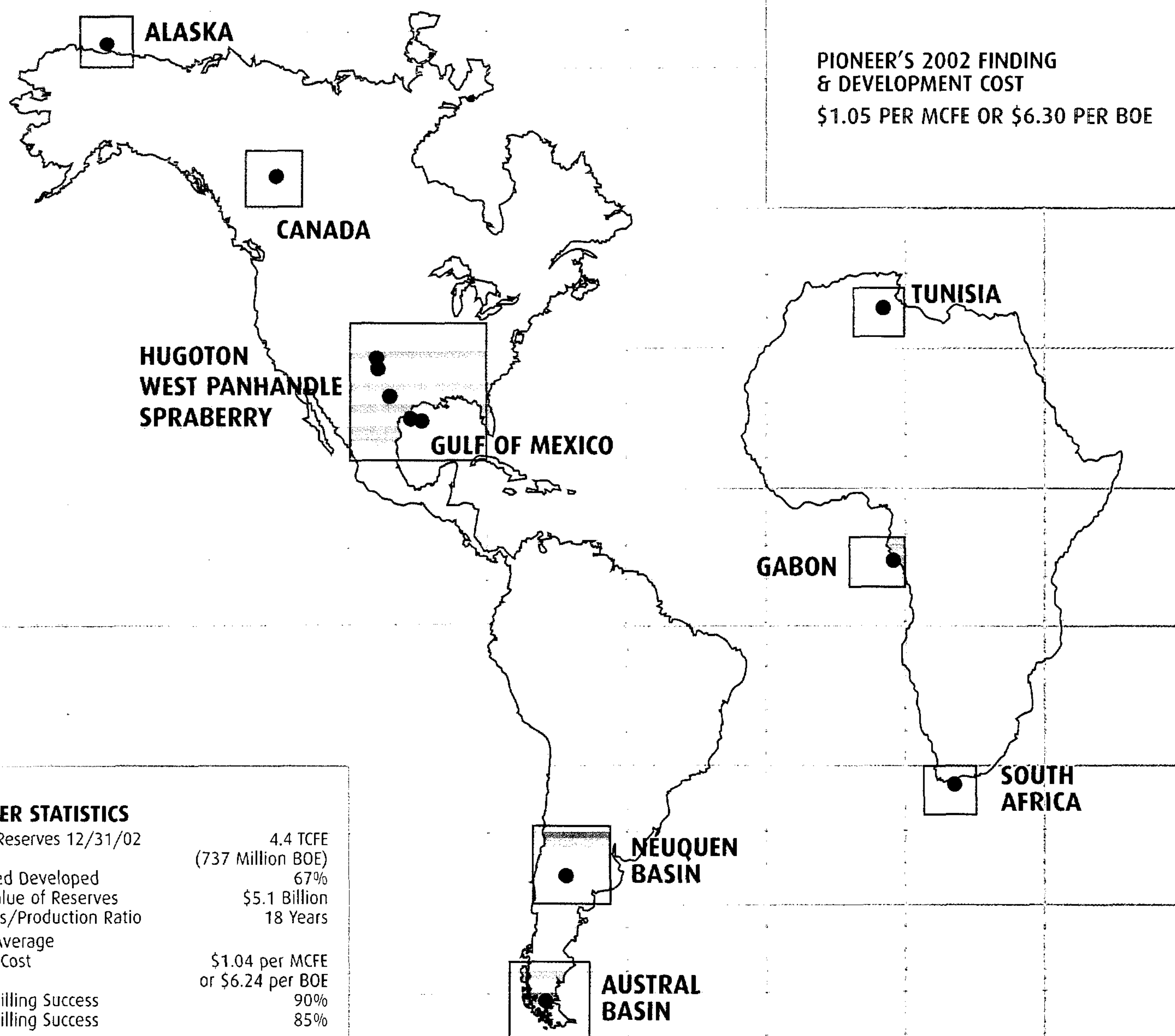
Annual Report
2002

THE HISTORY OF PIONEER

Pioneer Natural Resources Company was formed through the 1997 merger of Parker & Parsley Petroleum Company and MESA Inc. Both companies were built on the strategy of acquiring and exploiting proved properties and had built significant operated interests in quality long-lived fields. Pioneer is the largest operator in the Spraberry oil field in West Texas and one of the largest operators in the Hugoton gas field in Kansas and the West Panhandle gas field in the Texas Panhandle. These high-quality assets provide a solid base, continued development opportunity to increase production and significant cash flow in excess of that required to maintain their production. By investing this excess cash in a successful exploration program, Pioneer has created a production growth profile that is unmatched in the industry.

PIONEER'S 2002 FINDING & DEVELOPMENT COST

$1.05 PER MCFE OR $6.30 PER BOE



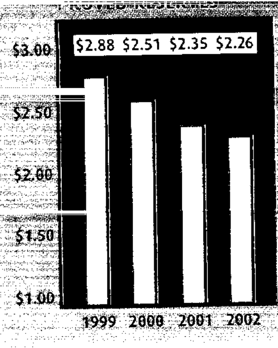
PIONEER STATISTICS

Proved Reserves 12/31/02	4.4 TCFE (737 Million BOE)
% Proved Developed	67%
PV10 Value of Reserves	$5.1 Billion
Reserves/Production Ratio	18 Years
3 Year Average Finding Cost	$1.04 per MCFE or $6.24 per BOE
2002 Drilling Success	90%
2001 Drilling Success	85%

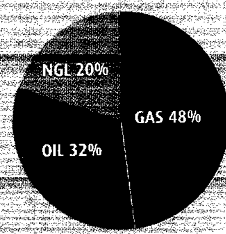
FORWARD-LOOKING STATEMENTS

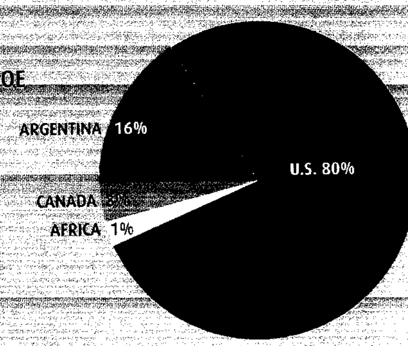
Except for historical information contained herein, the statements in this document are forward-looking statements that are made pursuant to the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995. Forward-looking statements and the business prospects of Pioneer Natural Resources Company are subject to a number of risks and uncertainties that may cause Pioneer's actual results in future periods to differ materially from the forward-looking statements. These risks and uncertainties include, among other things, volatility of oil and gas prices, product supply and demand, competition, government regulation or action, foreign currency valuation changes, foreign government tax and regulation changes, litigation, the costs and results of drilling and operations, Pioneer's ability to replace reserves, implement its business plans, or complete its development projects as scheduled, access to and cost of capital, uncertainties about estimates of reserves, quality of technical data, environmental and weather risks, acts of war and terrorism. These and other risks are described in Pioneer's 10-K and 10-Q Reports and other filings with the Securities and Exchange Commission.

YEAR-END DEBT PER BOE OF PROVED RESERVES



Proved Reserves *
4.4 TCFE/737 MILLION BOE





* Major property reserves were audited by independent petroleum engineers.

KEY EVENTS

AUG 1997	Pioneer Formed
JUN 1998	Sable Discovery
MAR 1999	Aconcagua Discovery
FEB 2000	Devils Tower Discovery
OCT 2000	Camden Hills Added
APR 2001	Falcon Discovery
MAY 2001	Gabon Discovery
OCT 2001	Ozona Deep Discovery
DEC 2001	Spraberry Acquisition
APR 2002	West Panhandle/ Falcon Acquisition
JUL 2002	Triton Discovery
SEP 2002	Tunisia Discovery
SEP 2002	Canyon Express First Production
JAN 2003	Harrier Discovery
APR 2003	Falcon First Production

ABOUT PIONEER

Pioneer Natural Resources Company is hitting its stride as a top-tier U.S. independent exploration and production company with a proven track record of increasing production and adding value for its shareholders and employees. With total proved reserves equivalent to 4.4 trillion cubic feet of gas or 737 million barrels of oil, Pioneer operates in the U.S., Canada, Argentina, South Africa, Gabon and Tunisia. Combined, these assets create a portfolio of resources and opportunities that are well balanced among oil, natural gas liquids and gas, and provide both dependable production and an array of exploration and development opportunities. Pioneer's reserves offer a longer than average productive life with a reserves-to-production ratio of 18 years.

Pioneer's three domestic core properties — the Hugoton and West Panhandle gas fields and the Spraberry oil and gas field — represent approximately 65 percent of the Company's total reserve base and produce strong, reliable cash flows that fund the Company's growth plans. These long-lived properties, together with core properties in Canada and Argentina, offer significant future development drilling opportunities.

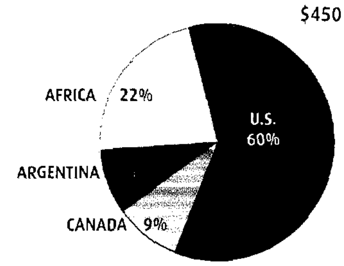
Pioneer's primary growth engine is exploration. Pioneer has successfully transformed itself from its acquisition and exploitation company roots into a successful exploration company by developing a staff of experienced geoscientists and investing in highly technical computing systems for seismic processing, geologic modeling and reservoir simulation. Over 20,000 square miles of 3-D seismic data have been acquired, assimilated and analyzed.

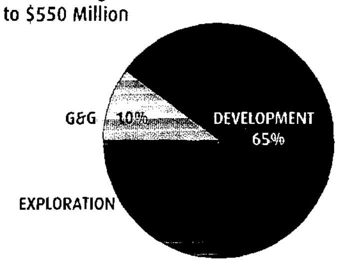
Important discoveries in the Gulf of Mexico, South Africa and Gabon are proof that the strategy is working. Pioneer's exploration strategy, supported by incremental acquisitions in key areas, has added significant proved reserves and the potential for 45 percent production growth during 2003 and 10 to 15 percent annually in 2004 and 2005. Pioneer also has several projects in the pipeline, in both the appraisal and prospect phases, which offer additional potential to extend reserve and production growth into 2004 and beyond.

DEFINITIONS

BOE: Barrel oil equivalent
MBOE: Thousand barrel oil equivalent
MCFE: Thousand cubic feet gas equivalent
MMCFE: Million cubic feet gas equivalent
TCFE: Trillion cubic feet gas equivalent
MBOPD: Thousand barrel oil production per day
MMCFPD: Million cubic feet gas production per day
MBOEPD: Thousand barrel oil equivalent production per day
MMCFEPD: Million cubic feet gas equivalent production per day

2003 CAPEX Budget
$450 to $550 Million





Scott D. Sheffield
Chairman, President and CEO

FELLOW SHAREHOLDERS:

Pioneer is hitting its stride. The Company enters 2003 poised for record performance, set to capitalize on the large investments we have made in developing new gas and oil production while maintaining the core properties that fund our growth. We expect our production to grow approximately 45 percent in 2003, and increase by an additional 10 to 15 percent annually in 2004 and 2005, significantly boosting our cash flow. Our stock price performance, which is the ultimate scorecard for our investors, reflects our successful execution in 2002, ending the year up over 30 percent and outperforming our peer group average and the broader market, and we have outstanding prospects still ahead.

We have the right strategy, the financial strength and the organizational agility to sustain an aggressive pace. Our strategy for growth combines selective investment in exploration balanced with aggressive development in our core areas and complementary acquisitions. Our financial strength comes from stable, long-lived core properties with reliable cash flows that we can reinvest in growth opportunities that meet our strict criteria on rates of return. Significant new production being added from four important development projects is building even more financial muscle. We believe Pioneer's size is a distinct advantage contributing to our success — large enough to have the resources to undertake major projects, like deepwater drilling in the Gulf of Mexico or international targets, but small enough that a reasonably-sized discovery still makes a major impact on our production rates.

Several discoveries are under evaluation for future development, and we are planning our most active exploration year yet in 2003. Any new discoveries resulting from Pioneer's extensive exploration program could further add to our already impressive production growth from existing projects.

2002 accomplishments show our strategy is working

In the fourth quarter of 2002, we began to see the impact on our financial returns from the investments we have made, although earnings for the full year were below 2001 primarily because of lower oil and gas price realizations and extraordinary charges. The Company reported full-year net income of $26.7 million, or $0.23 per diluted share, and reported cash flow from operations of $332.2 million.

Key operational measures underscore our success in 2002, and set the stage for exceptional performance in 2003 and beyond:

- Added 107 million BOE of proved oil and gas reserves
- Replaced 258 percent of production at $6.30 per BOE
- Drilled discoveries in the Gulf of Mexico, Argentina, Gabon and Tunisia
- Posted three-year reserve replacement of 210 percent at $6.24 per BOE
- Drilled 229 wells with 90 percent success rate
- Acquired additional interest in the Falcon field and surrounding area in the Gulf of Mexico and the West Panhandle field
- Added several major prospects to our exploration inventory
- Reduced long-term debt to $2.26 per BOE of proved reserves from $2.35 per BOE in 2001

Our complete financial and operating results for 2002 are presented in the accompanying Form 10-K.

New discoveries drive production growth

Four important discoveries form the backbone of our production growth, and are expected to substantially increase our cash flow:

Canyon Express: a deepwater Gulf of Mexico joint gas development with production initiated in September 2002 and reaching peak rates in 2003

Falcon: an operated gas field being developed in the deepwater Gulf of Mexico, expected to reach first production during April 2003

Sable: an oil field being developed offshore South Africa, expected to reach first production during the second quarter of 2003

Devils Tower: an oil field being developed in the deepwater Gulf of Mexico, expected to reach first production in early 2004

Other discoveries in the pipeline include the 2002 Triton field discovery in the Gulf of Mexico, which will be tied into the Devils Tower facility. First oil production from our 2002 Adam discovery drilled in Tunisia is expected in the second quarter of 2003. In Gabon, Pioneer has drilled and tested four successful offshore wells which have established significant oil in place, and we continue to evaluate the project to design the most cost-effective infrastructure for developing and producing that oil to maximize our return on investment. In early 2003, we made an additional gas discovery in the Falcon area with the Harrier satellite field. Production from Harrier is anticipated in late 2003 or early 2004.

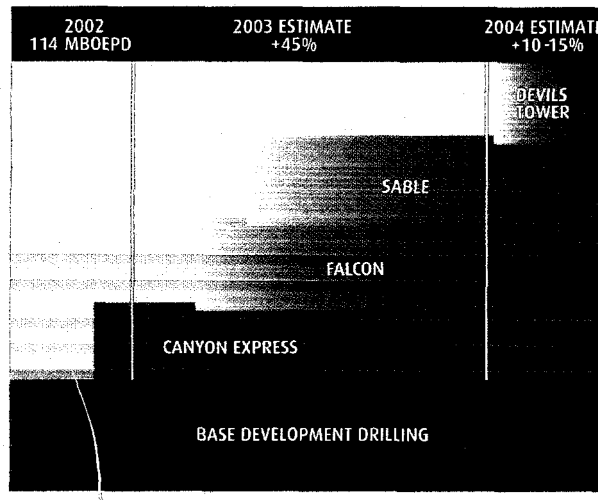
Drilling will nearly double in 2003

With most of the capital required for large project facilities for our four major development projects having been fulfilled during 2002, a higher percentage of the 2003 capital budget will be directed toward drilling activities. The Company plans to drill approximately 450 wells during 2003, up from 229 drilled in 2002, with only a modest increase in our capital budget of $450 million to $550 million. We plan to resume an aggressive development drilling program in our core onshore areas, doubling the number of onshore development wells planned. The exploration program includes plans to drill seven to 10 wells in the Gulf of Mexico, up to three wells in Alaska, six to nine wells in Tunisia, and three wells offshore South Africa. In Canada, 20 exploration wells are planned including 17 lower-cost, shallow gas tests, and we will continue to drill lower-risk stepout wells to extend our oil reserves in Argentina.

With increasing production from new projects combined with strong gas and oil prices, we expect to fund our capital budget with cash flow and expect significant excess cash flow to allocate to the development of exploration successes, core area acquisitions, debt reduction and/or share repurchases.

Our strong operating results are enhanced by a strong commodity price environment. North America gas prices are currently very strong, reflecting low inventory levels and declining supply. We expect that we will end the winter withdrawal season with U.S. inventories at or below their lowest historic levels and that refilling storage before next winter will be difficult considering the current decline in North America gas production. Several events threatening oil supplies have caused oil prices to climb. While we expect that prices will settle lower, we believe that excess capacity for oil production around the world has declined, increasing the likelihood that the Organization of Petroleum Exporting Countries (OPEC) will be able to maintain oil prices close to or within their target band of $22 to $28 per barrel.

DAILY PRODUCTION GROWTH



The Company expects 2003 production to be 60 percent gas and 40 percent oil and other liquids.

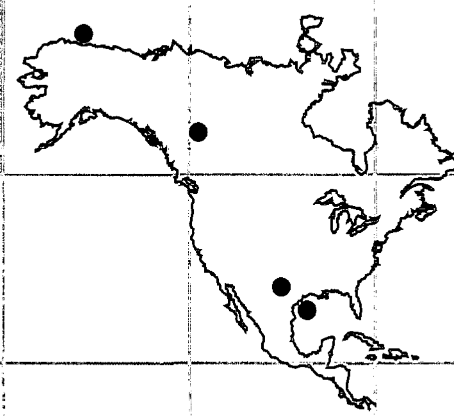
Right assets and right strategy for continued growth

We believe we are equipped to excel in this environment of change. While reserve replacement is becoming a greater challenge for our industry with prospect sizes diminishing and finding and development costs escalating, we are growing production and reserves. Pioneer expects ample cash flow to fund expansion efforts from a strong, stable platform of core assets. We will continue to concentrate on areas we know, and balance our investments among lower-risk development projects in our core areas and high-impact exploration.

In 2003, we will hit our stride and believe we can maintain an aggressive pace. Our track record gives us confidence that we can continue to grow production by 10 to 15 percent each year beyond 2003. We remain committed to you, our shareholders and employees, and appreciate your support.

Scott D. Sheffield

Scott D. Sheffield
Chairman, President and CEO



NORTH AMERICA: TOP-QUALITY ASSETS POWER OUR GROWTH STRATEGY

Pioneer's North America assets make up the core of the Company and provide a strong foundation representing 83 percent of worldwide proved reserves. Pioneer's North America portfolio is well-balanced and includes legacy gas and oil fields with strong, stable cash flow and extensive development opportunities, significant new field discoveries providing tremendous production growth and solid returns, and exciting prospects for future exploration.

The strategy in North America centers on adding value through the development of existing assets and by expanding the asset base through exploration and acquisitions. Pioneer's long-lived legacy assets offer above-average stability with shallow production declines as compared to industry averages. Consequently, these assets can be relied upon to provide dependable free cash flow after maintenance investments to commit to growth.

Pioneer plans to resume aggressive development of its onshore assets during 2003, doubling the number of development wells planned to be drilled, and expects moderate onshore production growth as a result. The Company has built an exceptional track record of exploration success in the deepwater Gulf of Mexico with tremendous production growth projected from the area through 2004 from three large projects currently producing or under development. Several new discoveries are being evaluated, and Pioneer plans to test additional prospects in the deepwater Gulf of Mexico and on the shelf during 2003. Acquiring incremental interests in core areas has proven to be a successful strategy for adding value, and the Company plans to continue to pursue similar core area acquisition opportunities in 2003.

A more detailed description of our core North American assets follows with our 2003 plans for capitalizing on the growth potential in each.

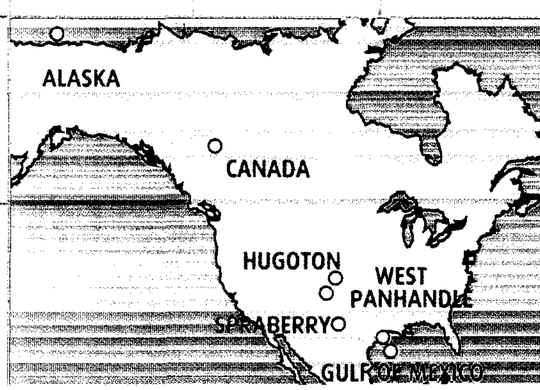
Onshore U.S.: Legacy assets provide stable base

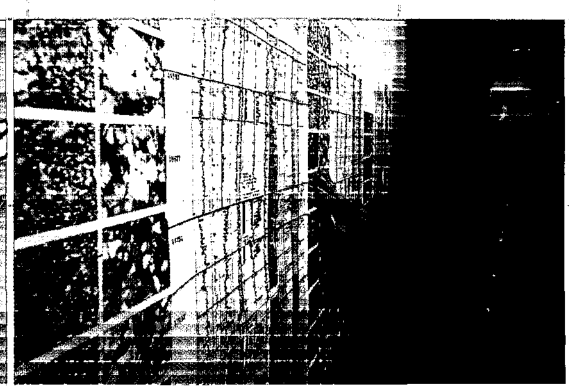
Pioneer's onshore U.S. holdings are concentrated in three key fields: the long-lived Hugoton and West Panhandle gas fields and the Spraberry oil and gas field, which represent approximately 65 percent of the Company's proved reserve base. With remaining productive lives of over 40 years, these fields not only generate cash flow for the Company's growth plan, but also offer extensive development opportunities.

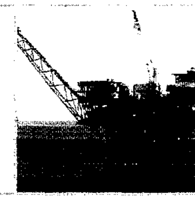
Hugoton field: The Hugoton field in southwest Kansas is one of the most prolific gas fields in the continental United States. Pioneer has a working interest in approximately 1,200 Hugoton wells, most of which are Company-operated, and owns substantially all of the gathering and processing facilities that service its production from the field, including the Satanta gas plant.

West Panhandle field: Pioneer is one of the largest operators in the West Panhandle gas field in the Texas Panhandle, where development drilling and incremental acquisitions have provided steady production growth for the Company. Pioneer has an interest in approximately 600 wells and continues to expand the field by drilling horizontal wells into formations that are less than 3,500 feet deep. In 2002, the Company purchased the remaining

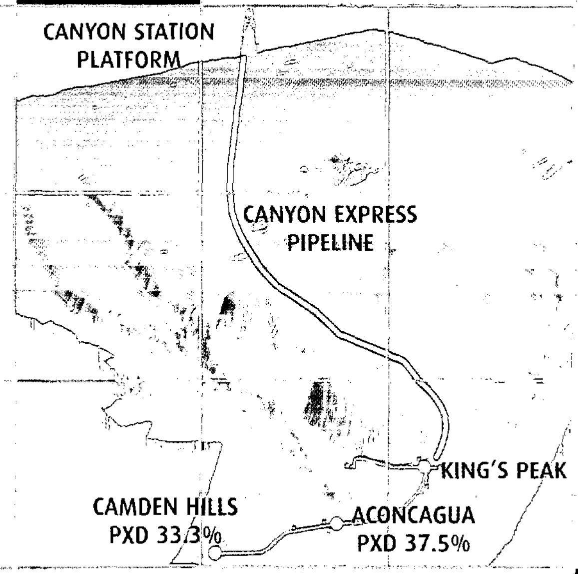
North America. Pioneer's growth strategy centers on expanding its asset base by selectively reinvesting the capital from its stable legacy fields in North America into exploration, development and acquisition opportunities that offer strong returns.







The Canyon Express system was the largest new project brought on production in 2002 to deliver gas to the U.S. market. The system includes three deepwater gas discoveries that were jointly developed and connected to the Canyon Station platform via a 55 mile pipeline. Pioneer owns an interest in the pipeline and two of the fields, Aconcagua and Camden Hills.



rights it did not already own in the field as well as the gathering system. Pioneer now controls the wells, production equipment, gathering system and gas processing plant for its portion of the field.

Spraberry field: Covering eight West Texas counties, the Spraberry field produces sweet crude and gas from formations between 6,700 and 9,200 feet deep. Pioneer is the largest operator in the field with interest in approximately 3,300 wells and a considerable inventory of future drilling locations.

2003 Plans: Pioneer drilled approximately 140 development wells on its onshore U.S. properties in 2002 and plans to double that number in 2003, drilling approximately 290 wells including:

- 30 Hugoton wells
- 100 West Panhandle wells
- 150 Spraberry wells

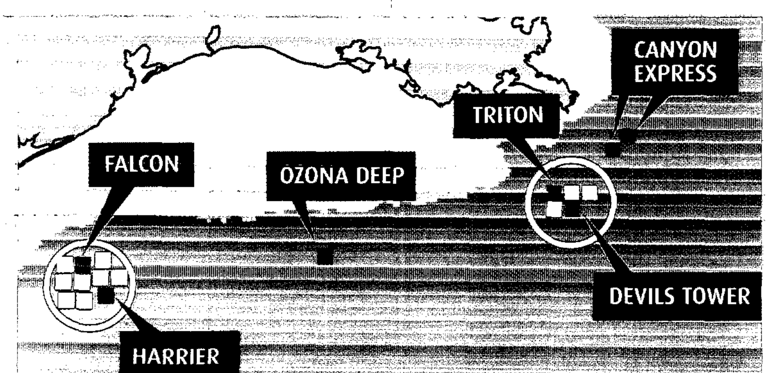
Deepwater Gulf of Mexico: Expanding track record of success

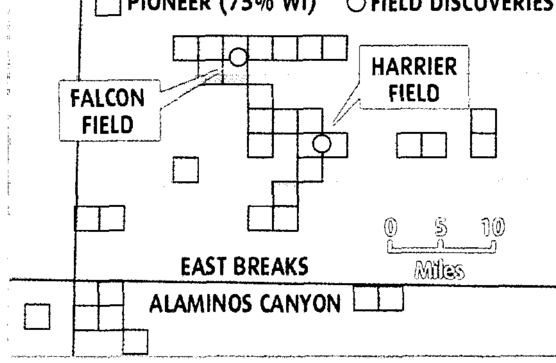
The Gulf of Mexico has been the focus of Pioneer's North America exploration program. Pioneer's deepwater Gulf of Mexico exploration strategy is driven by science rather than acreage position, with seismic interpretation leading the way to acreage acquisition and drilling. As a result of this strategy, Pioneer has seven significant deepwater field discoveries, four of which have been approved for development through three major deepwater projects. The Canyon Express project began producing in late 2002, and the Falcon and Devils Tower projects are expected to reach first production in 2003 and early 2004, respectively.

Canyon Express: The Canyon Express development project is a joint development of three deepwater Gulf of Mexico gas discoveries, including Pioneer's Aconcagua and Camden Hills fields. Pioneer participated in the discovery of the highly prolific Aconcagua gas field in 1999 during the early stages of building its exploration program, and later added Camden Hills to its portfolio to enhance its ownership in the project.

The Canyon Express project was approved for development in June 2000 and reached first production in September 2002. Production from Pioneer's two fields is expected to reach net peak rates of approximately 115 MMCFPD in early 2003, increasing the Company's net North America gas production over 40 percent from pre-project levels. The Canyon Express system is the first being built in the area, offering Pioneer and its partners the opportunity to collect gathering and handling revenues for the future use of the system.

Deepwater Gulf of Mexico. Pioneer has expanded its track record of success in the deepwater Gulf of Mexico with the successful appraisal of the Ozona Deep field and the discovery of the Triton field in 2002, and the discovery of the Harrier field in early 2003.





Falcon Area. Pioneer controls 32 blocks in the Falcon area and drilled its first satellite discovery, Harrier, in early 2003. The Falcon infrastructure was designed to accommodate future tie-in of satellite fields such as Harrier, and the Company has identified multiple prospects on its blocks for future exploration.

Falcon: Pioneer discovered the deepwater Falcon field in April 2001, encountering two excellent quality gas-bearing sands. The Falcon field, located 100 miles east of Corpus Christi, was approved for development in October 2001 and is being developed by tying back two subsea wells to the new Falcon Nest platform located on the shelf approximately 30 miles away. Pioneer is the operator of the field with a 75 percent working interest. First gas production from the Falcon field is expected in April of 2003 with peak gas production rates expected to reach approximately 175 MMCFPD or approximately 130 MMCFPD net to Pioneer's working interest.

Devils Tower: Pioneer and its partner discovered the multi-pay Devils Tower oil field in 2000 and approved its development in June 2001. The field is being developed using a truss spar with slots for eight dry tree wells and the flexibility to accommodate future subsea tie-backs. The hull of the spar was constructed in Indonesia and is in transit to the U.S. where the topsides will be added. The eight producing wells have been drilled and are awaiting completion. Production is scheduled to begin in early 2004 and will be phased in as the wells are individually completed from the spar. The spar has been designed with excess capacity to handle 60 MBOPD and 60 MMCFPD. Pioneer holds a 25 percent working interest in the field.

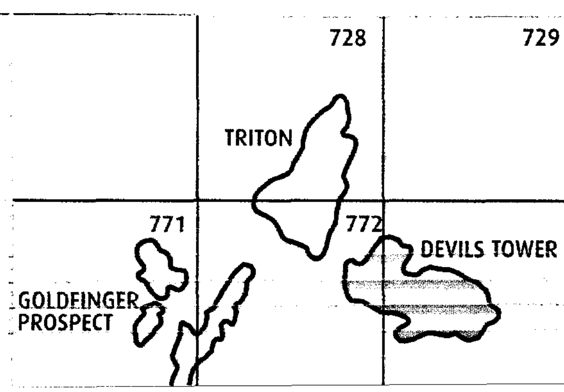
Development plans are in progress for three additional deepwater discoveries: the Harrier field in the Falcon corridor, the Triton field in the Devils Tower area and the Ozona Deep field in the Auger mini-basin. The Harrier and Triton fields were discovered as a result of Pioneer's strategy to leverage the infrastructure being developed for its Falcon and Devils Tower projects by focusing on prospects within tie-back range of these early discoveries. Utilizing existing infrastructure reduces the cost of developing satellite field reserves and significantly enhances economic returns.

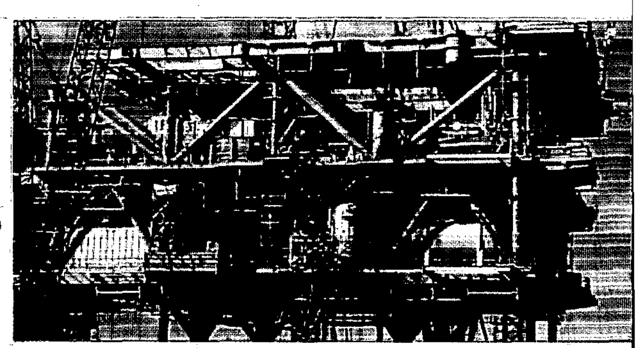
Pioneer discovered the deepwater Harrier field in early 2003, encountering over 350 feet of gas-bearing sand in a single zone. Pioneer operates the block with a 75 percent working interest and expects to develop the field as a single-well subsea tie-back to the Falcon field facilities which were designed to be expandable. First production from the Harrier field is anticipated in nine to 15 months.

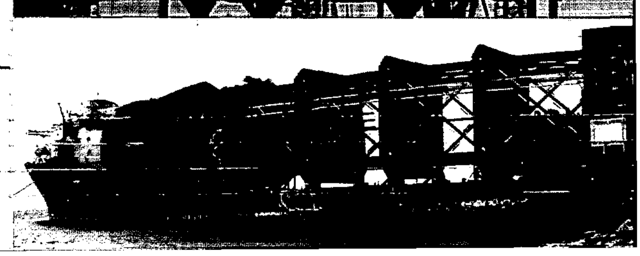
The deepwater Triton field was discovered in 2002 with 80 feet of net pay in two intervals and is slated for subsea tie-back to the spar for the Devils Tower project. Pioneer has a 25 percent working interest in the field.

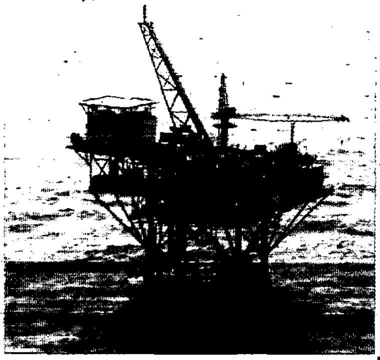
During 2002, Pioneer successfully appraised its 2001 Ozona Deep discovery. The original discovery encountered 345 feet of net oil pay in two intervals, and the Company is evaluating possible tie-back opportunities to existing third-party facilities in the area. Pioneer owns a 32 percent working interest in the field.

Devils Tower Area. The deepwater Devils Tower field is being developed with a floating truss spar. The hull of the spar is in transit from Indonesia and will be joined with the topsides in the U.S. for expected first production in early 2004. Pioneer discovered a satellite field, Triton, in 2002 which will be tied back to the same spar and has identified other prospects for future drilling.









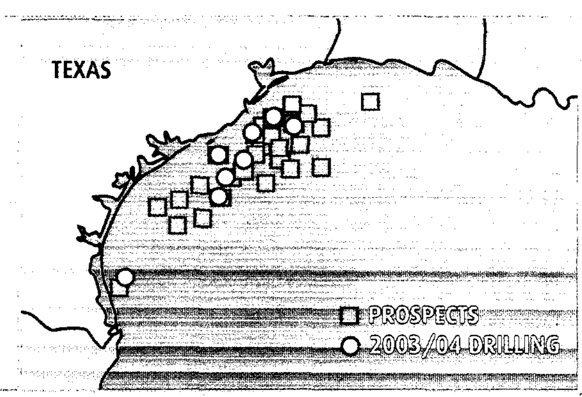
Subsea wells from Pioneer's Falcon field were tied back to the Falcon Nest platform on the Gulf of Mexico shelf. The platform was installed in early 2003 and has the capacity to process additional gas from satellite discoveries in the Falcon area.

2003 Plans: As discussed above, Pioneer has had early success in 2003 with the deepwater Harrier discovery and expects to complete development plans on the Harrier, Triton and Ozona Deep fields during the year. Prospects in the Falcon and Devils Tower areas are the immediate focus of future deepwater drilling plans. The Company has identified several prospects on the 32 blocks it holds in the Falcon area and plans to drill at least one additional exploration well in 2003. Pioneer has identified several additional prospects near its Devils Tower field that it plans to drill upon the commencement of production from the field. The Company is also evaluating several prospects on blocks it holds in other areas of the deepwater Gulf of Mexico and plans to begin to test these prospects in its 2004 drilling program.

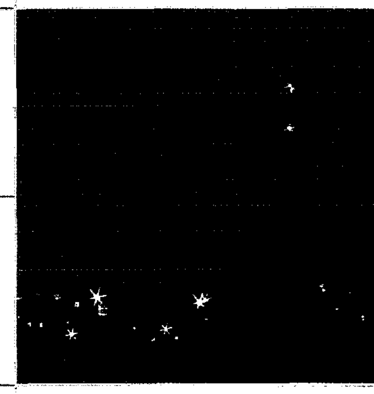
Gulf of Mexico Shelf: Program targets significant deep gas potential

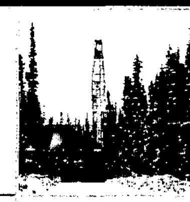
Deep gas on the shallow shelf is also a focus of Pioneer's Gulf of Mexico exploration strategy. When the play was targeted in 1997, the Company began an extensive regional study of existing deep gas production and acquired extensive 2-D and 3-D seismic data. Acreage was gradually acquired as prospects were identified, resulting in a current inventory of 27 prospects covering 47 blocks. Early drilling resulted in three discoveries, with the most significant being the Stirrup field, discovered in 2001.

2003 Plans: In January 2003, Pioneer announced that a subsidiary of Woodside Energy Ltd. of Australia had signed an agreement to join Pioneer for a two-year shelf drilling program. Under the agreement, Woodside has taken a 50 percent working interest in Pioneer's blocks and has agreed to participate in the drilling of at least eight wells, five in 2003 and three in 2004. Pioneer is the designated operator of the blocks, and most of the wells to be drilled under the agreement target potential gas below 15,000 feet. However, the partners plan to evaluate several shallower gas prospects on the shelf blocks covered under the agreement.



Gulf of Mexico Shelf. Pioneer holds 47 blocks and an inventory of 27 prospects on the shelf and plans to drill at least eight wells in 2003 and 2004 targeting deep gas prospects with significant reserve potential.





Pioneer is leveraging its Canadian winter-access drilling expertise for its exploration efforts in Alaska. Above, a rig operates in the twilight of the Alaskan winter.

Alaska: Acreage position offsets prolific oil field

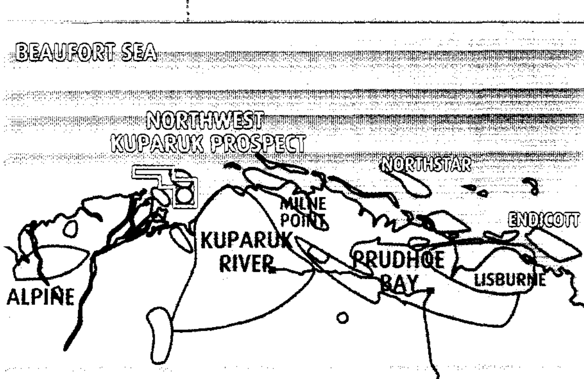
Pioneer entered Alaska in 2002, gaining a 70 percent working interest in ten state leases on the North Slope covering approximately 14,000 undeveloped acres between the Kuparuk River unit and Thetis Island. The acreage is offshore in approximately five to ten feet of water. No wells have been drilled on the acreage covered by Pioneer's leases to date, but wells drilled just outside the perimeter of the acreage have encountered several sands that were oil-bearing.

2003 Plans: The Company plans to drill up to three wells in early 2003 to test an area that is prospective for oil in the same sands as the offsetting Kuparuk River unit, eight to ten miles to the southeast.

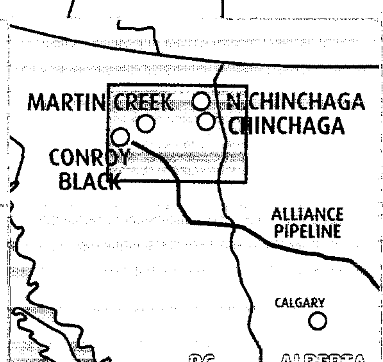
Canada: Opportunities to expand North American gas reserves

In Canada, Pioneer's activities focus on its core area in northeast British Columbia and just across the border into Alberta. Pioneer's Canadian assets are largely company-operated shallow gas fields in the Chinchaga, Martin Creek and Lookout Butte areas. Development of these fields continues, and the Company is expanding its exploration program in Canada targeting lightly drilled lands with potential to extend the plays present in existing producing areas. Pioneer's acreage position is strategically located at the northern end of the Alliance Pipeline, which delivers Canadian gas directly to the Chicago market.

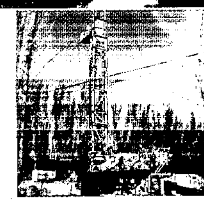
2003 Plans: Pioneer plans to drill approximately 39 development wells during the 2002/2003 winter drilling season targeting production growth of 5 to 10 percent, and plans to drill 20 exploration wells including 17 lower-cost, shallow gas tests.



Alaska. Pioneer holds interest in ten state leases on the North Slope covering approximately 14,000 acres offsetting the prolific Kuparuk River unit.



Canada. Pioneer's activities focus on its assets in northeast British Columbia and western Alberta at the northern end of the Alliance pipeline which delivers Canadian gas directly to the Chicago market.

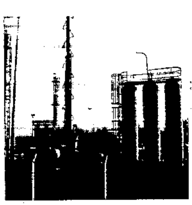


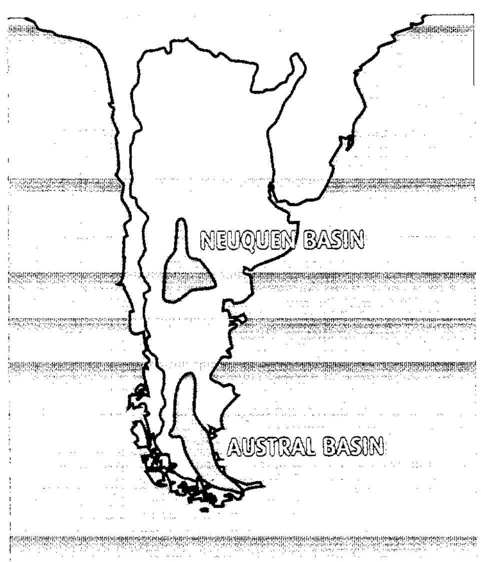
ARGENTINA: CORE AREA OFFERS RICH OPPORTUNITY FOR EXPLOITATION

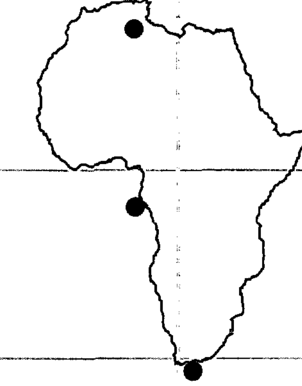
Pioneer's Argentine properties are concentrated in two prolific oil and gas producing provinces, the Neuquen and Austral basins, covering approximately two million acres. The Neuquen basin, located about 925 miles southwest of Buenos Aires and to the east of the Andes Mountains, is relatively undeveloped and offers significant opportunity for exploitation and development. Pioneer operates most of its production from this area and processes most of its gas at the Company's recently completed Loma Negra gas processing plant. Exploration efforts focus on drilling lower-risk stepout wells to extend existing oil field reserves.

Pioneer's Austral basin assets are located in Tierra del Fuego, an island in the extreme southern portion of Argentina, approximately 1,500 miles south of Buenos Aires. These assets offer stable production and considerable oil and gas exploration opportunities.

2003 Plans: Pioneer plans to drill over 50 oil development wells during 2003, taking advantage of the drilling, operating and administrative cost reductions resulting from the devaluation of Argentina's currency in early 2002. Oil revenues were reduced by an export tax imposed in early 2002 and are U.S. dollar-denominated.







AFRICA: EXPLORATION SUCCESSES BRING NEW PRODUCTION IN 2003

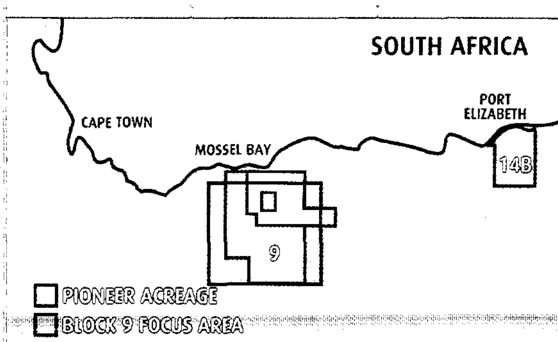
Pioneer has entered into agreements to explore for oil and gas in South Africa, Gabon and Tunisia. Pioneer expects to achieve its first production in Africa when the Sable field begins producing offshore South Africa, anticipated during the summer of 2003, to be followed closely by production from the Adam discovery in Tunisia. Pioneer has other field discoveries in South Africa and Gabon that are currently being evaluated for potential development and plans to continue its exploration activities in South Africa and Tunisia during 2003.

South Africa: Sable field to increase worldwide oil production 45 percent

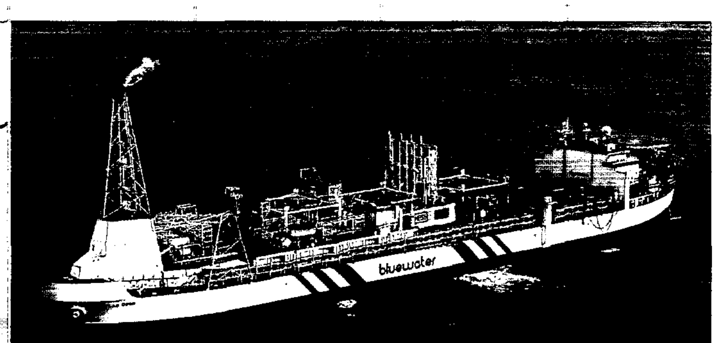
Offshore South Africa, where Pioneer has exploration and production contracts covering approximately five million acres, the Company partnered with the government-owned oil company, applied current 3-D seismic technology, and with its first well, discovered the Sable oil field in 1999. Two subsequent appraisal wells were also successful, and in June 2001, the field was approved for development utilizing a floating production, storage and offloading (FPSO) vessel. Pioneer anticipates first production in the summer of 2003 at gross daily rates of 35 to 40 MBOPD from four wells in which the Company has a 40 percent interest. When the project begins production, it is expected to increase Pioneer's worldwide oil production by approximately 45 percent.

Along the southern rim of the same basin that holds the Sable field, Pioneer drilled its Boomslang discovery during 2001 testing both oil and gas. Pioneer acquired new 3-D seismic data to refine its prospects in the areas surrounding the Sable field and the Boomslang discovery to potentially increment its production and extend the utilization of the FPSO vessel.

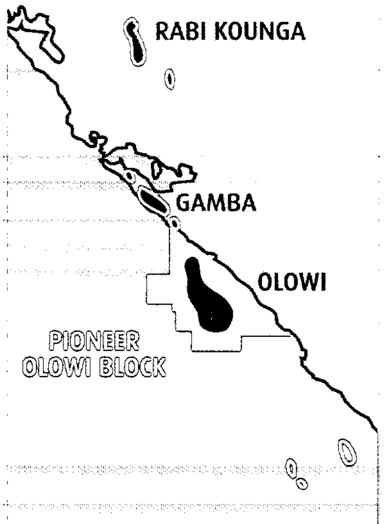
2003 Plans: Pioneer plans to drill three exploration wells offshore South Africa during 2003. The presence of a significant amount of gas has been established through drilling by Pioneer and its predecessors to the South Africa permits. To take advantage of this opportunity, Pioneer is negotiating a price for the potential sale of gas to a facility onshore that converts gas to synthetic fuels. If a satisfactory price is negotiated, Pioneer's exploration plans could include drilling wells to determine if sufficient gas reserves are available to begin a gas development project.



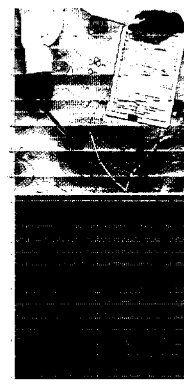
South Africa. Pioneer holds contracts covering approximately five million acres off the southern coast of South Africa, the most populated and industrialized region of the country. Block 9 has been the primary focus of Pioneer's exploration efforts including the Sable discovery that is expected to begin production in 2003.



Subsea wells will be tied back to a floating production, storage and offloading (FPSO) vessel to develop and produce Pioneer's Sable field oil reserves.



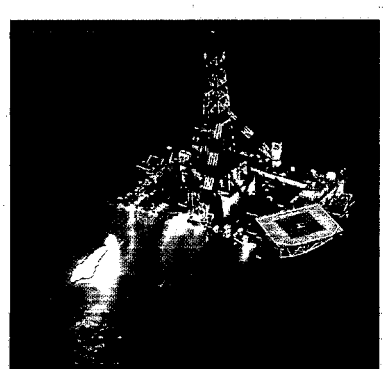
Gabon. Pioneer's Olowi Block off the coast of Gabon covers 314,000 acres in 50 to 85 feet of water and is on trend with two large onshore subsalt fields.

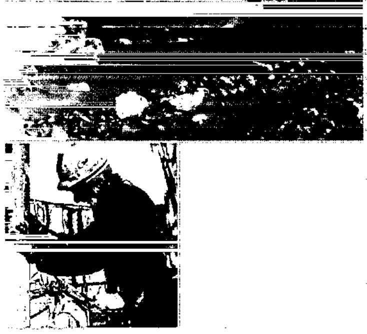


Gabon: Significant oil discovery being evaluated

Pioneer's position off the coast of Gabon covers approximately 314,000 acres, generally in water depths less than 100 feet. During 2002, Pioneer drilled three wells and successfully extended the oil accumulation the Company discovered on its Bigorneau South prospect on the Olowi block in 2001. To date, the Company has drilled and tested four successful offshore wells. Three of the wells were tested and each well flowed at a rate of more than 2,000 barrels of oil per day, establishing significant oil in place. Pioneer operates the Olowi block with a 100 percent working interest.

2003 Plans: Full development of the field is expected to involve substantial capital investment underscoring the importance of confirming reservoir characteristics and productivity. Pioneer is seeking bids for the development of an early production system covering a limited field area which would allow the Company to gain additional information needed to design a full field development plan. The Company is also seeking improved fiscal terms from the government.





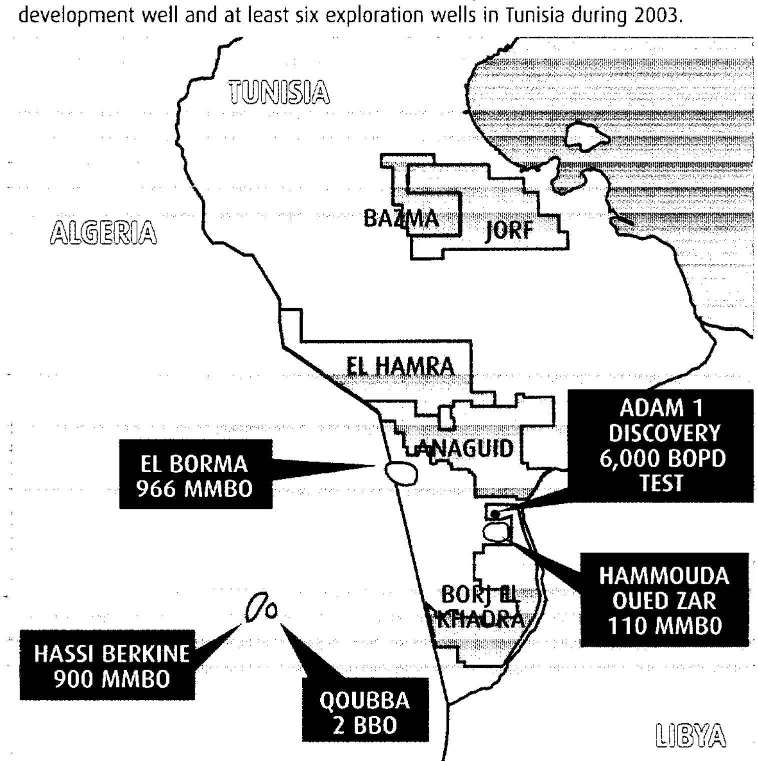
Tunisia: Production from Adam discovery expected in 2003

Having identified the prolific Ghadames Basin as a target for entry into North Africa, Pioneer acquired leases on four blocks covering approximately four million acres in southern Tunisia during 2001. A fifth block was added in 2002, for a total current position of approximately five million acres. This onshore play offers the benefit of lower cost, shallow targets in an area with an existing pipeline infrastructure.

In September 2002, Pioneer announced a discovery on the Adam prospect in its Borj El Khadra block that encountered several oil and gas productive zones in Silurian sands that tested at 6,000 barrels of oil per day. Pioneer's interest in the block is 40 percent. First production is expected during the third quarter of 2003 upon completion of a 15 kilometer flow line from the discovery to existing facilities. An additional development well is scheduled to be drilled in the fourth quarter of 2003.

2003 Plans: In addition to the Adam development well, at least six exploration wells are planned in Tunisia in 2003 to test the Company's prospects targeting the Silurian and TAGI sands which extend into Tunisia from Libya and Algeria, respectively.

Tunisia. Pioneer's leases cover approximately five million acres on five blocks. Pioneer participated in the Adam 1 discovery during 2002 and plans to drill a development well and at least six exploration wells in Tunisia during 2003.



2002

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, 2002

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. [ ]

Indicate by check mark whether the Registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).
YES X NO ___

Aggregate market value of the voting common equity held by non-affiliates of the Registrant computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the Registrant's most recently completed second fiscal quarter	**$3,011,384,455**
Number of shares of Common Stock outstanding as of February 17, 2003	**117,299,334**

Documents Incorporated by Reference:

(1) Proxy Statement for Annual Meeting of Shareholders to be held May 15, 2003 - Referenced in Part III of this report.

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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; **"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 unit and is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit; **"LIBOR"** means London Interbank Offered Rate, which is a market rate of interest; **"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; and **"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.

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 currency 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. 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; Capetown, South Africa; and Tunis, Tunisia. At December 31, 2002, the Company had 979 employees, 491 of whom were employed in field and plant operations.

Available Information

Pioneer files annual, quarterly, and current reports, proxy statements, and other documents with the SEC under the Securities Exchange Act of 1934. The public may read and copy any materials that Pioneer files with the SEC at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an Internet website that contains reports, proxy and information statements, and other information regarding issuers, including Pioneer, that file electronically with the SEC. The public can obtain any documents that Pioneer files with the SEC at http://www.sec.gov.

The Company also makes available free of charge on or through its Internet website (http://www.pioneernrc.com) its Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after it electronically files such material with, or furnishes it to, the SEC.

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 65 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, combined with: (i) production from the Company's Canyon Express gas project which began production in September 2002; (ii) the initial production from the Company's Falcon gas discovery in the deepwater Gulf of Mexico and the Sable oil discovery in South Africa expected during the second quarter of 2003; and (iii) initial production from the Company's Devils Tower oil discovery in the deepwater Gulf of Mexico expected during the first quarter of 2004, will generate the operating cash flows that will provide Pioneer with continued financial flexibility. These 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 fluctuating oil, NGL and gas commodity prices and relatively stable supplier costs during the three years ended December 31, 2002. During and just prior to 2000, the Organization of Petroleum Exporting Countries ("OPEC") 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. During 2002, world oil prices increased in response to political unrest and supply disruptions in the Middle East and Venezuela. During the third and fourth quarters of 2002, North American gas prices improved as market fundamentals strengthened. The Company's outlook for 2003 commodity prices is uncertain. Significant factors that will impact 2003 commodity prices include the final resolution of issues currently impacting Iraq and Venezuela; the extent to which members of OPEC and other oil exporting nations are able to manage oil supply through export quotas; and overall North American gas supply and demand fundamentals. To mitigate the impact of volatile commodity prices on the Company's net asset value, Pioneer periodically enters into commodity hedge contracts. See Note J 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 2002, 2001 and 2000 from the Company's hedging activities and the Company's open hedge positions at December 31, 2002.

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/or oil and gas production activities in Alaska, 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 2002, the Company's average daily oil, NGL and gas production decreased primarily due to normal production declines, reduced Argentine demand for gas, the Company's curtailment of Argentine drilling activities during the first half of 2002 and the December 2001 sale of the Company's Rycroft/Spirit River field in Canada. During 2001 and 2000, 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 2002, 2001 and 2000 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, 2002, the Company drilled 1,810 gross (1,279.7 net) wells, 88.5 percent of which were successfully completed as productive wells, at a total drilling cost (net to the Company's interest) of $1.6 billion. During 2002, the Company drilled 229 gross (153.2 net) wells. Drilling and facility costs (net to the Company's interest) totaled $439.3 million during 2002, 79 percent of which was spent on development activities including $221.6 million towards completing the Canyon Express, Falcon and Devils Tower deepwater Gulf of Mexico projects and the Sable project offshore South Africa. The Company's current 2003 capital expenditure budget is expected to range from $450 million to $550 million. Excluding the 2002 Falcon field and West Panhandle field acquisitions, the Company's 2003 capital expenditure budget is comparable to 2002 costs incurred for oil and gas producing activities. Development expenditures to complete the Falcon, Devils Tower and Sable projects will decline to approximately $35 million during 2003, while aggressive development drilling programs in the Company's core Spraberry oil field, Hugoton and West Panhandle gas fields, the United States Gulf Coast, Argentina and Canada will resume with approximately twice as many wells anticipated in 2003 versus 2002. The Company has allocated the budgeted 2003 capital expenditures as follows: 65 percent to development drilling and facility activities and 35 percent 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, 2002 include proved undeveloped reserves and proved developed reserves that are behind pipe of 154.2 million Bbls of oil and NGLs and 647.7 Bcf of gas. Development of those reserves will require future capital expenditures. The timing of the development of these reserves will be dependent upon the commodity price environment, the Company'sexpected 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; the 1999 Aconcagua, 2000 Devils Tower, 2001 Falcon and 2003 Harrier discoveries in the deepwater Gulf of Mexico; the 2001 Olowi permit discovery located in the Southern Gabon basin; and the 2002 Borj El Khadra permit discovery in the Ghadames basin onshore Southern Tunisia. The Company currently anticipates that its 2003 exploration efforts will be approximately 35 percent of total 2003 expenditures and will be concentrated domestically in Alaska and the Gulf of Mexico, 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 2002, 2001 and 2000, the Company's divestitures consisted of the early termination of derivative hedge contracts and the sales of oil and gas properties and other assets for net proceeds of $118.9 million, $113.5 million and $102.7 million, respectively, which resulted in 2002, 2001 and 2000 net divestiture gains of $4.4 million, $7.7 million and $34.2 million, respectively. The Company's 2002 net proceeds from asset divestitures were primarily derived from the early termination of interest rate and commodity hedges and the sale of certain gas properties in Oklahoma. The Company's 2001 divestitures were primarily derived from the 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 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-strategic United States oil and gas properties located in Oklahoma, New Mexico and Louisiana. The net cash proceeds from the 2002, 2001 and 2000 asset dispositions were primarily used to fund additions to oil and gas properties or to reduce the Company's outstanding indebtedness. See Note M ofNotes 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 or other assets 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 2002, the Company expended $195.5 million of acquisition capital to purchase additional interests in, and other assets associated with, its Falcon field development project in the deepwater Gulf of Mexico and its West Panhandle gas field and unproved property interests in the Gulf of Mexico, the Alaskan North Slope, the Borj El Khadra permit in Tunisia and other areas. The Company purchased, through two transactions, an additional 30 percent working interest in the Falcon field development and a 25 percent working interest in associated acreage in the deepwater Gulf of Mexico for a combined purchase price of $61.1 million. As a result of these transactions, the Company owns a 75 percent working interest and operates the Falcon field development and related exploration blocks.

The Company also completed the purchase of the remaining 23 percent of the rights that the Company did not already own in its core area West Panhandle gas field, 100 percent of the West Panhandle reserves attributable to field fuel, 100 percent of the related West Panhandle field gathering system and ten blocks surrounding the Company's deepwater Gulf of Mexico Falcon discovery. In connection with these transactions, the Company recorded a $100.4 million increase to proved oil and gas properties, a $3.8 million increase to unproved oil and gas properties and $1.9 million of assets held for resale; retired a capital cost obligation for $60.8 million; settled a $20.9 million gas balancing receivable; assumed trade and environmental obligations amounting to $5.8 million in the aggregate; and paid $140.2 million of cash.

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 affiliated limited partnerships. Additionally, $77.9 million was spent during 2001 to acquire additional working interests in the deepwater Gulf of Mexico Aconcagua discovery, the related Canyon Express gathering system and the Devils Tower project; 21 deepwater 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 deepwater 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 deepwater Gulf of Mexico discovery and the related Canyon Express gathering system during 2000.

See Note D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's acquisitions.

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 2002, 2001 and 2000, the Company had oil and gas producing activities in the United States, Argentina and Canada, and hadexploration and/or development 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 2002, the Company's primary purchasers of oil were ExxonMobil Corporation ("ExxonMobil") and Plains Marketing LP ("Plains"), 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 of the Company's 2002 combined oil, NGL and gas revenues were attributable to sales to each of ExxonMobil, Plains, Williams and Anadarko. 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 J 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 2002, 2001 and 2000 from the Company's commodity hedging activities and the Company's open commodity hedge positions at December 31, 2002.

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. Enterprises that sell securities in public markets are subject to regulatory oversight by agencies such as the United States Securities and Exchange Commission. This regulatory oversight imposes on the Company the responsibility for establishing and maintaining disclosure controls and procedures that will ensure that material information relating to the Company and its consolidated subsidiaries is made known to the Company's management and that the financial statements and other financial information included in this Report do not contain any untrue statement of a material fact, or omit to state a material fact, necessary to make the statements made in this Report not misleading.

Oil and gas exploration and production operations are also subject to various types of regulation by local, state, federal and foreign agencies. Additionally, the Company's operations are 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 respectto 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 gasexploration 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. A significant downward trend in commodity prices 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, 2002 and 2001, the Company carried unproved property costs of $219.1 million and $187.8 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.

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, 2002, the Company owns interests in 11 natural gas processing plants and five treating facilities. The Company operates seven of the plants and all five 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 the high premium costs associated with obtaining such insurance.

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 corporate credit facility. The terms of the Company's borrowings under the senior notes and the corporate credit facility 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 E 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, 2002, approximately 20 percent of the Company's proved reserves of oil, NGLs and gas were located outside the United States (16 percent in Argentina, three 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 Estimates 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, 2002 was based on reserve reports audited by Netherland, Sewell & Associates, Inc. for the Company's major properties in Canada, South Africa and the United States, reserve reports audited by Gaffney, Cline & Associates, Inc. for the Company's properties located in the Neuquen Basin in Argentina, and reserve reports prepared by the Company's engineers for all other properties. The reserve audits conducted by Netherland, Sewell & Associates, Inc. and Gaffney, Cline & Associates, Inc., in aggregate, represented 71 percent of the Company's estimated proved quantities of reserves as of December 31, 2002. The information in this Report about the Company's oil, NGL and gas reserves as of December 31, 2001 and 2000 was 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 2002, 2001 or 2000 to any federal authority or agency, other than the SEC.

Proved Reserves

The Company's proved reserves totaled 736.7 million BOE at December 31, 2002, 671.4 million BOE at December 31, 2001 and 628.2 million BOE at December 31, 2000, representing $4.1 billion, $2.5 billion and $5.6 billion, respectively, of Standardized Measure or $5.1 billion, $2.5 billion and $7.0 billion, respectively, on a pre-tax basis. The ten percent increase in reserve volumes and 65 percent increase in Standardized Measure during 2002 were attributable to an increase in commodity prices, the purchase of incremental interests in two core assets and the Company's successful capital investments. 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.

On a BOE basis, 67 percent of the Company's total proved reserves at December 31, 2002 were proved developed reserves. Based on reserve information as of December 31, 2002, and using the Company's production information for 2002, the reserve-to-production ratio associated with the Company's proved reserves was 18 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, 2002:

PROVED OIL AND GAS RESERVES AND AVERAGE DAILY PRODUCTION

	Proved Reserves as of December 31, 2002				2002 Average Daily Production (a)		
	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE	Standardized Measure (000)	Oil & NGLs (Bbls)	Gas (Mcf)	BOE
United States	337,631	1,483,971	584,960	$ 3,456,691	43,949	232,360	82,677
Argentina	31,532	532,081	120,211	340,106	8,680	78,220	21,716
Canada	2,361	119,328	22,249	199,012	1,070	48,365	9,131
South Africa	8,475	-	8,475	121,363	-	-	-
Tunisia	845	-	845	9,380	-	-	-
Total	380,844	2,135,380	736,740	$ 4,126,552	53,699	358,945	113,524

(a) The 2002 average daily production was calculated using a 365-day year and without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred during the year.

Finding Cost and Reserve Replacement

The Company's acquisition and finding costs per BOE for 2002, 2001 and 2000 were $6.30, $7.49 and $4.66 per BOE, respectively. The average acquisition and finding cost for the three-year period from 2000 to 2002 was $6.24 per BOE, representing a 32 percent increase over the 2001 three-year average rate of $4.74 per BOE. This increase was largely attributable to the $221.6 million of development capital that the Company spent during 2002 to develop its Canyon Express, Falcon and Devils Tower development projects in the deepwater Gulf of Mexico and its Sable development project offshore South Africa.

During 2002, the Company replaced 258 percent of its annual production on a BOE basis (384 percent for oil and NGLs and 144 percent for gas). 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). The Company's 2002 reserve replacement percentage was the result of revisions of previous estimates and revisions related to changes in commodity prices, asset purchases and new discoveries and field extensions. The Company's 2001 reserve replacement percentage was primarily impacted by asset purchases and new discoveries and field extensions while the 2000 reserve replacement percentage was primarily impacted by revisions related to changes in commodity prices.

Description of Properties

As of December 31, 2002, the Company has production and/or development and exploration operations in the United States, Argentina, Canada, South Africa and Tunisia, and exploration opportunities in Gabon.

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. The Company also has unproved properties in Alaska. Approximately 82 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 2002, the Company expended $533.6 million in domestic acquisition, exploration and development drilling activities. The Company has budgeted approximately $300 million for domestic acquisition, exploration and development drilling expenditures for 2003.

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, many of which are reflected in the Company's proved undeveloped reserves, and the ability to reduce operating expenses through economies of scale.

During 2002, the Company placed 89 Spraberry wells on production, drilled one developmental dry hole and, at December 31, 2002, had two wells in progress. The Company plans to drill approximately 150 development wells in the Spraberry field during 2003.

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.

The Company's Hugoton operated wells are capable of producing approximately 97 MMcf of wet gas per day (i.e., gas production at the wellhead before processing and before reduction for royalties), although actual production in the Hugoton field is limited by allowables set by state regulators. The Company estimates that it and other major producers in the Hugoton field produced at or near capacity in 2002. During 2002, the Company completed four development wells in the Hugoton field and plans for 2003 include approximately 30 wells to be drilled.

The Company is continuing to evaluate 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 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. In 2002, the Company purchased the remaining rights it did not already own in the field as well as the gathering system. The Company now controls the wells, production equipment, gathering system and gas processing plant for the field.

During 2002, the Company placed 40 new wells on production, drilled three developmental dry holes and had four wells in progress at December 31, 2002. The Company plans to drill approximately 100 wells in the West Panhandle field during 2003.

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 2002, the Company successfully drilled six development and four exploratory wells in the deepwater Gulf of Mexico and one successful exploratory well and one successful development well on the shelf. The Company also drilled two exploratory dry holes in the deepwater Gulf of Mexico and one exploratory dry hole on the shelf during 2002.

In the deepwater Gulf of Mexico, the Company has sanctioned three major development projects, one of which is now on production and two that were in progress at December 31, 2002:

- Canyon Express - The TotalFinaElf-operated Aconcagua and the Marathon-operated Camden Hills discoveries in Mississippi Canyon were jointly developed as part of the Canyon Express gas project. Production start-up occurred in late September; however, several operational and mechanical difficulties were encountered which has resulted in the Company not reaching its estimated net production level of 110 to 120 MMcf of gas per day until late January 2003.

- 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 and three development wells. 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 in progress, the eight producing wells on Devils Tower have been drilled and are awaiting completion and production is anticipated to begin during the first quarter of 2004. The wells will be brought on sequentially with peak production expected to reach 12,000 to 15,000 BOEs per day net to the Company's 25 percent working interest.

- Falcon - The Company-operated Falcon project is on pace to be on production in April 2003. Two development wells were drilled and completed during 2002 and the final stages of the facilities fabrication and installation are currently underway. Peak production from Falcon is anticipated at rates of approximately 130 MMcf of gas per day net to the Company's 75 percent working interest.

During 2002, the Company also participated in two appraisal sidetrack wells on the Marathon-operated deepwater Gulf of Mexico Ozona Deep prospect, of which one was a discovery. The 2002 discovery sidetrack appraisal well further extended the 2001 Ozona Deep discovery that originally encountered approximately 345 feet of net oil pay in two intervals. The Company is currently evaluating possible tie-back opportunities to existing facilities in the area, the economics of which will determine future activities. The Company also successfully drilled its Dominion-operated Triton prospect near Devils Tower. Proved reserves were recorded for this prospect and it will be completed as a subsea tieback to Devils Tower. Exploration drilling near the Falcon discovery began in December 2002 with the Lightning prospect and in January 2003 on the H2.5 and Harrier prospects. The Lightning and H2.5 exploratory wells were unsuccessful; however, the Harrier prospect was announced as a discovery in late January 2003. It is anticipated that the Harrier well will be completed with a subsea tieback to Falcon within nine to 15 months. During 2003, the Company also plans to drill its Buff prospect, which is also near the Falcon discovery.

During January 2003, the Company announced a joint exploration agreement with Woodside Energy (USA) Inc. ("Woodside"), a subsidiary of Woodside Energy Ltd. of Australia, for a two-year drilling program over the shallow-water Texas shelf region of the Gulf of Mexico. Under the agreement, Woodside has taken a 50 percent working interest in 47 offshore exploration blocks operated by the Company. The agreement covers eight prospects and 19 leads and includes five exploratory wells to be drilled in 2003 and three in 2004. Most of the wells to be drilled under the agreement will target gas plays below 15,000 feet. The eight wells to be drilled by the parties in 2003 and 2004 are on prospects generated and leased by the Company since 1997. Additionally, the Company and Woodside will evaluate for potential inclusion in the drilling program shallower gas prospects on the Gulf of Mexico shelf on other blocks covered by the leases.

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 six development wells at Pawnee during 2002, had one well in progress at year end and plans to drill seven wells in 2003.

Alaska area. During the fourth quarter of 2002, the Company signed an agreement with Armstrong Resources LLC under which the Company was assigned a 70 percent working interest and operatorship in ten state leases on Alaska's North Slope. The leases cover approximately 14,000 undeveloped acres between the Kuparuk River unit and Thetis Island. The Company plans to drill up to three exploratory wells during the first quarter of 2003. The wells will test an area that the Company believes is prospective for oil in the same sands as the offsetting Kuparuk River unit eight to ten miles to the southeast. The Kuparuk River unit was discovered in 1969 and is estimated to hold 2.5 billion barrels of recoverable oil. No wells have been drilled on the acreage covered by the Company's leases to date, but wells drilled just outside the perimeter of the acreage have encountered the primary target Kuparuk "C" sands and were oil-bearing. The acreage is offshore in approximately five to ten feet of water. Drilling plans call for grounded sea ice pad locations that will be accessed via ice roads from Oliktok Point dock. All sea ice operations are expected to be completed by the end of March 2003.

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 other significant development projects, the Sable oil field located in shallow water offshore South Africa and the Adam discovery in southern Tunisia, are scheduled for first production in mid-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, 2002, approximately 16 percent, three percent, one percent and one tenth of one percent of the Company's proved reserves are located in Argentina, Canada, South Africa and Tunisia, respectively.

Argentina. The Company's share of Argentine production during 2002 averaged 21.7 MBOE per day, or approximately 19 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 to the east of the Andes Mountains. Oil and gas are produced primarily from the Al Norte de la Dorsal, the Al Sur de la Dorsal, the Dadin, the Loma Negra, the Anticlinal Campamento and the Estacion Fernandez Oro blocks, in each of which the Company has a 100 percent working interest. Most of the gas produced from these blocks is processed in the Company's recently completed Loma Negra gas processing plant. The Company also operates and has a 50 percent working interest in the Lago Fuego field which is located in Tierra del Fuego, an island in the extreme southern portion of Argentina, approximately 1,500 miles south of Buenos Aires.

Most of the Company's non-operated production in Argentina is located in Tierra del Fuego where oil, gas and NGLs are produced from six separate fields in which the Company has a 35 percent working interest. The Company also has a 14.4 percent working interest in the Confluencia field which is located in the Neuquen Basin.

During 2002, the Company expended $35.1 million on Argentine development and exploration activities. The Company drilled 14 development wells and 17 extension/exploratory wells, of which 13 development wells and nine extension/exploratory wells were successful. Also during 2002, the Company completed its gas processing plant at Loma Negra and completed a 35 mile gas pipeline that connects the Loma Negra plant to a main gas transmission line that accesses the Buenos Aires gas market. The Company plans to spend approximately $45 million on oil and gas development and exploration opportunities in Argentina during 2003.

Canada. The Company's Canadian producing properties are located primarily in Alberta and British Columbia, Canada. Production during 2002 averaged 9.1 MBOE per day, or approximately eight 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.

During 2002, the Company expended $33.5 million on Canadian development, exploration and acquisition activities. The Company drilled 17 development wells and 12 exploratory wells, primarily in the Chinchaga and Martin Creek areas, of which 13 development wells and 9 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 plans to spend approximately $45 million on oil and gas development and exploration opportunities in Canada during 2003.

Africa. In Africa, the Company has entered into agreements to explore for oil and gas in South Africa, Gabon and Tunisia. The amended South African agreements cover over five million acres along the southern coast of South Africa, generally in water depths less than 650 feet. The Gabon agreement covers 313,937 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 2.9 million acres onshore southern Tunisia which the Company operates with a 50 percent working interest and the second includes the Anadarko-operated Anaguid permit covering 1.2 million acres onshore southern Tunisia in which the Company has a 38.7 percent working interest and the AGIP-operated Borj El Khadra permit covering 1.2 million acres onshore southern Tunisia in which the Company has a 40 percent working interest. During 2002, the Company expended $70.3 million of acquisition, development and exploration drilling and seismic capital in South Africa, Gabon and Tunisia.

South Africa. In South Africa, the Company spent $37.1 million of drilling and seismic capital to drill four successful development wells on its Petro SA-operated Sable development project. During 2003, the Company plans to complete its Sable development project with production anticipated to begin during the second quarter of 2003. Production for the first year is expected to average approximately 12,100 Bbls of oil per day net to the Company's 40 percent working interest. In addition, the Company currently plans to drill three exploration wells in South Africa during 2003.

Gabon. In Gabon, the Company spent $23.6 million of drilling and seismic capital to drill and test three additional exploratory wells 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. To date, the Company has drilled and tested four successful offshore wells which have established significant oil in place. Full development of the field is expected to involve substantial capital investment underscoring the importance of confirming reservoir characteristics and productivity. Pioneer is currently seeking bids for the development of an early production system covering a limited field area which would allow the Company to gain additional information needed to design a full field development plan. The Company is also seeking improved fiscal terms from the government.

Tunisia. In Tunisia, the Company spent $8.2 million of acquisition, drilling and seismic capital primarily to acquire a 40 percent interest in and drill an exploration well on the AGIP-operated Borj El Khadra permit. This well encountered several oil and gas productive zones that tested up to 6,000 Bbls of oil per day. The Company plans to complete the construction of a 15 kilometer flowline from thediscovery to an AGIP-operated facility during the third quarter of 2003, allowing production to begin from the initial well shortly thereafter. A development well is scheduled to be drilled in the fourth quarter of 2003. In addition to this development project, plans for Tunisia in 2003 include an exploration well to be drilled on the Company-operated Jorf permit, two exploration wells to be drilled on the Anadarko-operated Anaguid permit and an additional exploration well to be drilled on the AGIP-operated Borj El Khadra permit.

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, 2002, 2001 and 2000. 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 being 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, 2002, 2001 and 2000:

PRODUCTION, PRICE AND COST DATA (a)

	Year Ended December 31,											
	2002				2001				2000			
	United States	Argentina	Canada	Total	United States	Argentina	Canada	Total	United States	Argentina	Canada	Total
Production information:												
Annual production:												
Oil (MBbls)	8,555	2,914	45	11,514	8,629	3,566	303	12,498	8,989	3,238	308	12,535
NGLs (MBbls) ..	7,487	254	345	8,086	7,232	200	368	7,800	7,883	193	303	8,379
Gas (MMcf)	84,811	28,551	17,653	131,015	77,609	31,830	18,426	127,865	83,930	35,695	16,219	135,844
Total (MBOE) ..	30,177	7,926	3,333	41,436	28,796	9,071	3,742	41,609	30,861	9,380	3,314	43,555
Average daily production:												
Oil (Bbls)	23,437	7,984	124	31,545	23,641	9,769	831	34,241	24,561	8,847	841	34,249
NGLs (Bbls) ...	20,512	696	946	22,154	19,815	547	1,008	21,370	21,538	527	829	22,894
Gas (Mcf)	232,360	78,220	48,365	358,945	212,629	87,204	50,481	350,314	229,316	97,526	44,315	371,157
Total (BOE)	82,677	21,716	9,131	113,524	78,894	24,851	10,253	113,997	84,318	25,628	9,056	119,002
Average prices, including hedge results:												
Oil (per Bbl) ...	$ 23.66	$ 20.63	$ 22.26	$ 22.89	$ 24.34	$23.79	$ 21.87	$ 24.12	$ 22.07	$29.09	$ 27.50	$ 24.01
NGLs (per Bbl) .	$ 13.77	$ 14.56	$ 16.77	$ 13.92	$ 16.88	$19.29	$ 21.11	$ 17.14	$ 20.05	$22.91	$ 24.32	$ 20.27
Gas (per Mcf) ..	$ 3.16	$ .48	$ 2.50	$ 2.49	$ 4.10	$ 1.31	$ 2.86	$ 3.23	$ 3.50	$ 1.19	$ 2.88	$ 2.81
Revenue (per BOE)	$ 19.00	$ 9.79	$ 15.27	$ 16.94	$ 22.56	$14.36	$ 17.94	$ 20.36	$ 21.04	$15.03	$ 18.85	$ 19.58
Average prices, excluding hedge results:												
Oil (per Bbl) ...	$ 23.85	$ 20.33	$ 22.26	$ 22.95	$ 24.56	$22.40	$ 21.87	$ 23.88	$ 28.76	$29.09	$ 27.50	$ 28.81
NGLs (per Bbl) .	$ 13.77	$ 14.56	$ 16.77	$ 13.92	$ 16.88	$19.29	$ 21.11	$ 17.14	$ 20.05	$22.91	$ 24.32	$ 20.27
Gas (per Mcf) ..	$ 3.02	$ .48	$ 2.40	$ 2.38	$ 3.96	$ 1.31	$ 3.27	$ 3.20	$ 3.73	$ 1.19	$ 3.45	$ 3.03
Revenue (per BOE)	$ 18.65	$ 9.68	$ 14.77	$ 16.63	$ 22.26	$13.81	$ 19.95	$ 20.21	$ 23.63	$15.03	$ 21.65	$ 21.63
Average costs:												
Production costs (per BOE):												
Lease operating .	$ 3.21	$ 1.61	$ 2.64	$ 2.87	$ 2.76	$ 2.64	$ 3.01	$ 2.76	$ 2.45	$ 2.30	$ 2.53	$ 2.42
Taxes:												
Production. ...	.71	.13	-	.54	.98	.28	-	.74	.99	.30	-	.77
Ad valorem ...	.75	-	-	.54	.71	-	-	.49	.41	-	-	.29
Field fuel	.85	-	-	.62	1.27	-	-	.88	1.01	-	-	.71
Workover	.28	.01	.59	.25	.20	.01	.32	.17	.17	-	.42	.15
Total	$ 5.80	$ 1.75	$ 3.23	$ 4.82	$ 5.92	$ 2.93	$ 3.33	$ 5.04	$ 5.03	$ 2.60	$ 2.95	$ 4.34
Depletion expense												
(per BOE)	$ 4.64	$ 5.00	$ 8.36	$ 5.01	$ 4.46	$ 5.67	$ 7.71	$ 5.02	$ 3.95	$ 5.56	$ 7.58	$ 4.57

(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, 2002, 2001 and 2000:

PRODUCTIVE WELLS (a)

	Gross Productive Wells			Net Productive Wells		
	Oil	Gas	Total	Oil	Gas	Total
As of December 31, 2002:						
United States	3,448	1,952	5,400	2,745	1,855	4,600
Argentina	694	208	902	534	142	676
Canada	1	246	247	1	197	198
South Africa	4	-	4	2	-	2
Tunisia	1	-	1	-	-	-
Total	4,148	2,406	6,554	3,282	2,194	5,476
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

(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, 2002, the Company owned interests in 111 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, 2002:

LEASEHOLD ACREAGE

	Developed Acreage		Undeveloped Acreage		Royalty
	Gross Acres	Net Acres	Gross Acres	Net Acres	Acreage
As of December 31, 2002:					
United States:					
Onshore	996,896	871,234	198,729	156,815	229,686
Offshore	125,786	53,120	604,287	506,712	10,500
	1,122,682	924,354	803,016	663,527	240,186
Argentina	710,000	299,000	1,002,000	925,000	-
Canada	152,000	116,000	356,000	276,000	12,000
South Africa	9,600	3,840	5,368,400	4,009,160	-
Gabon	-	-	313,937	313,937	-
Tunisia	-	-	5,308,498	2,402,667	-
Total	1,994,282	1,343,194	13,151,851	8,590,291	252,186

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, 2002, 2001 and 2000. This information should not be considered indicative of future performance, nor should it be assumed that there was 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 holes.

DRILLING ACTIVITIES

	Gross Wells Year Ended December 31,			Net Wells Year Ended December 31,		
	2002	2001	2000	2002	2001	2000
United States:						
Productive wells:						
Development	148	228	159	83.0	114.6	91.3
Exploratory	6	20	11	2.0	11.0	4.7
Dry holes:						
Development	4	15	3	3.7	14.6	1.9
Exploratory	3	8	3	2.1	5.1	1.6
	161	271	176	90.8	145.3	99.5
Argentina:						
Productive wells:						
Development	13	19	28	13.0	17.7	26.7
Exploratory	9	26	38	9.0	25.5	37.6
Dry holes:						
Development	1	1	2	1.0	1.0	2.0
Exploratory	8	16	16	8.0	14.0	14.5
	31	62	84	31.0	58.2	80.8
Canada:						
Productive wells:						
Development	13	24	17	10.4	20.3	17.9
Exploratory	9	12	12	9.0	10.2	9.9
Dry holes:						
Development	4	2	4	4.0	2.0	2.5
Exploratory	3	13	2	3.0	11.8	1.9
	29	51	35	26.4	44.3	32.2
Africa:						
Productive wells:						
Development	4	-	-	1.6	-	-
Exploratory	4	3	-	3.4	2.4	-
Dry holes:						
Development	-	-	-	-	-	-
Exploratory	-	3	1	-	1.9	1.0
	8	6	1	5.0	4.3	1.0
Total	229	390	296	153.2	252.1	213.5
Success ratio (a)	90%	85%	90%	86%	80%	88%

(a) Represents the ratio of those wells that were successfully completed as producing wells or wells capable of producing to total wells drilled and evaluated.

The following table sets forth information about the Company's wells upon which drilling was in progress on December 31, 2002:

	Gross Wells	Net Wells
United States:		
Development	7	6.5
Exploratory	-	-
	7	6.5
Argentina:		
Development	3	3.0
Exploratory	6	6.0
	9	9.0
Canada:		
Development	4	4.0
Exploratory	4	4.0
	8	8.0
Total	24	23.5

ITEM 3. LEGAL PROCEEDINGS

The Company is party to various legal proceedings, which are described under "Legal actions" in Note I 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 2002.

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 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 2002 or 2001. The Company's board of directors has no current plans to declare dividends during the foreseeable future.

	High	Low
Year ended December 31, 2002:		
Fourth quarter	$ 27.50	$ 21.70
Third quarter	$ 26.23	$ 19.50
Second quarter	$ 26.05	$ 20.00
First quarter	$ 22.30	$ 16.10
Year ended December 31, 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

On February 14, 2003, the last reported sales price of the Company's common stock, as reported in the New York Stock Exchange composite transactions, was $24.25 per share.

As of February 14, 2003, the Company's common stock was held by approximately 30,951 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,				
	2002	2001	2000	1999	1998
	(in millions, except per share data)				
Statement of Operations Data:					
Revenues and other income:					
Oil and gas	$ 701.8	$ 847.0	$ 852.7	$ 644.6	$ 711.5
Interest and other (a)	11.2	21.8	25.8	89.7	10.4
Gain (loss) on disposition of assets, net	4.4	7.7	34.2	(24.2)	(.4)
	717.4	876.5	912.7	710.1	721.5
Costs and expenses:					
Oil and gas production	199.6	209.7	189.3	159.5	223.5
Depletion, depreciation and amortization	216.4	222.6	214.9	236.1	337.3
Impairment of properties and facilities	-	-	-	17.9	459.5
Exploration and abandonments	85.9	127.9	87.5	66.0	121.9
General and administrative	48.4	37.0	33.3	40.2	82.6
Reorganization	-	-	-	8.5	33.2
Interest	95.8	131.9	162.0	170.3	164.3
Other (b)	17.2	39.6	67.2	34.7	30.0
	663.3	768.7	754.2	733.2	1,452.3
Income (loss) before income taxes and extraordinary items	54.1	107.8	158.5	(23.1)	(730.8)
Income tax benefit (provision)	(5.1)	(4.0)	6.0	.6	(15.6)
Income (loss) before extraordinary items	49.0	103.8	164.5	(22.5)	(746.4)
Extraordinary items (c)	(22.3)	(3.8)	(12.3)	-	-
Net income (loss)	$ 26.7	$ 100.0	$ 152.2	$ (22.5)	$ (746.4)
Income (loss) before extraordinary items per share:					
Basic	$ .44	$ 1.05	$ 1.65	$ (.22)	$ (7.46)
Diluted	$ .43	$ 1.04	$ 1.65	$ (.22)	$ (7.46)
Net income (loss) per share:					
Basic	$ .24	$ 1.01	$ 1.53	$ (.22)	$ (7.46)
Diluted	$ .23	$ 1.00	$ 1.53	$ (.22)	$ (7.46)
Dividends per share	$ -	$ -	$ -	$ -	$ .10
Weighted average shares outstanding:					
Basic	112.5	98.5	99.4	100.3	100.1
Diluted	114.3	99.7	99.8	100.3	100.1
Statement of Cash Flows Data:					
Cash flows from operating activities	$ 332.2	$ 475.6	$ 430.1	$ 255.2	$ 314.1
Cash flows from investing activities	$ (508.1)	$ (422.7)	$ (194.5)	$ 199.0	$ (517.0)
Cash flows from financing activities	$ 170.9	$ (64.0)	$ (244.1)	$ (479.1)	$ 190.9
Balance Sheet Data (as of December 31):					
Working capital (deficit)	$ (127.5)	$ 27.4	$ (25.1)	$ (13.7)	$ (324.8)
Property, plant and equipment, net	$ 3,168.4	$ 2,784.3	$ 2,515.0	$ 2,503.0	$ 3,034.1
Total assets	$ 3,455.1	$ 3,271.1	$ 2,954.4	$ 2,929.5	$ 3,481.3
Long-term obligations	$ 1,796.9	$ 1,743.7	$ 1,804.5	$ 1,914.5	$ 2,101.2
Total stockholders' equity	$ 1,374.9	$ 1,285.4	$ 904.9	$ 774.6	$ 789.1

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

(b) Other expense for 2002 includes $6.9 million and $2.6 million for the remeasurement of Argentine peso-denominated net monetary assets and Canadian gas marketing losses, respectively. 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 noncash 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.

(c) The Company's extraordinary items represent losses from the early extinguishment of debt. See Notes B and E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the Company's extraordinary items.

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

2002 Financial and Operating Performance

The year ended December 31, 2002 was highlighted by favorable commodity prices and continued strengthening of North American gas fundamentals; the issuance of 11.5 million shares of common stock to fund strategic acquisitions in the Company's core areas of the West Panhandle gas field and the Gulf of Mexico Falcon field development project; initial production from the Canyon Express gas project; continued development of the deepwater Gulf of Mexico Devils Tower and Falcon fields and the Sable oil field offshore South Africa; indications that the Argentine economy and currency may be stabilizing; continued evaluation of the Gabon discovery; an oil discovery in Tunisia; the acquisition of undeveloped property interests in Alaska; the completion of a public offering of $150 million of 7-1/2 percent senior notes that will mature in 2012; and repurchases of $61.0 million of higher yielding funded debt to reduce the Company's future costs of capital.

During the years ended December 31, 2002, 2001 and 2000, the Company recorded net income of $26.7 million, $100.0 million and $152.2 million ($.23, $1.00 and $1.53 per diluted share), respectively. Compared to 2001, the Company's 2002 total revenues and other income decreased by $159.0 million, or 18 percent, including a $145.2 million decrease in oil and gas revenues. The decrease in oil and gas revenues was due to decreases of five percent, 19 percent and 23 percent in average oil, NGL and gas prices, respectively, including the effects of commodity price hedges.

Compared to 2001, the Company's 2002 total costs and expenses decreased by $105.4 million, or 14 percent. The decrease in total costs and expenses was primarily reflective of a $42.0 million decrease in exploration and abandonments expense, primarily due to the allocation of a larger percentage of the Company's 2002 capital budget to the development of the Company's Canyon Express, Falcon, Devils Tower and Sable projects; a $36.1 million decrease in interest expense, primarily due to declining underlying market interest rates, interest savings associated with the replacement of higher yielding senior notes and capital cost obligations with lower yielding senior notes and corporate credit facility indebtedness, interest rate hedge gains and increased interest capitalized on significant capital projects; and a $22.3 million decrease in other expense, primarily due to declines in derivative mark-to-market provisions, gas marketing losses and bad debt expense.

During the year ended December 31, 2002, the Company's net cash provided by operating activities decreased to $332.2 million, as compared to $475.6 million during 2001 and $430.1 million during 2000. The decrease in net cash provided by operating activities during 2002 was primarily due to declines in oil, NGL and gas prices as discussed above.

During 2002, successful capital investment activities increased the Company's proved reserves to 736.7 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 258 percent of production at an acquisition and finding cost per BOE of $6.30. During the three years ended December 31, 2002, Pioneer has replaced 210 percent of production at an acquisition and finding cost per BOE of $6.24. Costs incurred for the year ended December 31, 2002 totaled $672.5 million, including $195.5 million of proved and unproved property acquisitions and $477.0 million of exploration and development drilling and seismic expenditures.

During the year ended December 31, 2002, the Company purchased, through two transactions, an additional 30 percent working interest in the Falcon field development and a 25 percent working interest in associated acreage in the deepwater Gulf of Mexico for a combined purchase price of $61.1 million. As a result of these transactions, the Company owns a 75 percent working interest in and operates the Falcon field development and related exploration blocks. Also during 2002, the Company completed the purchase of the remaining 23 percent of the rights that the Company did not already own in its core area West Panhandle gas field, 100 percent of the West Panhandle reserves attributable to field fuel, 100 percent of the related West Panhandle field gathering system and ten blocks surrounding the Company's deepwater Gulf of Mexico Falcon discovery. In connection with these transactions, the Company recorded $100.4 million to proved oil and gas properties, $3.8 million to unproved oil and gas properties and $1.9 million to assets held for resale; retired a capital cost obligation for $60.8 million; settled a $20.9 million gas balancing receivable; assumed trade and environmental obligations amounting to $5.8 million in theaggregate; and paid $140.2 million of cash.

See "Results of Operations" and "Capital Commitments, Capital Resources and Liquidity", 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.

2003 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. World oil prices increased during 2002 in response to political unrest and supply disruptions in the Middle East and Venezuela. During the third and fourth quarters of 2002, North American gas prices improved as market fundamentals strengthened. The Company's outlook for 2003 commodity prices is uncertain. Significant factors that will impact 2003 commodity prices include the final resolution of issues currently impacting Iraq and Venezuela, 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 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, 2002, the Company had hedged 22,236 barrels per day ("Bblpd") of 2003 oil production under swap contracts with a weighted average fixed price to be received of $24.45 per Bbl. The Company had also hedged 230,000 Mcf per day of 2003 gas production under swap contracts with a weighted average fixed price to be received of $3.76 per MMBtu. During January 2003, the Company increased its 2003 commodity hedge positions by entering into 6,000 Bblpd of March oil swap contracts with average per Bbl fixed prices of $33.51. Additionally, at December 31, 2002 the Company has deferred oil hedge losses of $.5 million that will be recognized as reductions to oil revenue during the last eight months of 2003 and $72.5 million of gas hedge gains that will be recognized as increases to gas revenue during 2003. See Note J 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, 2002. Also see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for disclosures about the Company's commodity related derivative financial instruments.

First quarter 2003. Based on current estimates, the Company expects that its first quarter worldwide production will average 120 to 128 MBOE per day. Included in the mid-point of the estimate is 95 MMcf per day, net to the Company from Canyon Express. First quarter production costs are expected to average $5.10 to $5.40 per BOE based on recent NYMEX strip prices for oil and gas. Depreciation, depletion and amortization expense is expected to average $5.75 to $6.00 per BOE, and total exploration and abandonment expense is expected to be $20 million to $50 million. General and administrative expense is expected to be $16 million to $17 million during the first quarter of 2003, $2 million to $3 million of which relates to estimated additional performance-based compensation costs. Interest expense is expected to be $24 million to $26 million. Interest capitalized during the first quarter of 2003 will be significantly less than interest capitalized during the first three quarters of 2002 as the Company's largest capital project for which interest was being capitalized, the Canyon Express development project, was put into production during September 2002. Additionally, during February 2003, the Company entered into interest rate swap contracts to hedge a portion of the fair value of its 9-5/8 percent senior notes. Under the terms of the interest rate swap contracts, the Company will receive a fixed annual rate of 9-5/8 percent on $250 million notional amount and will pay the counterparties a variable rate on the notional amount equal to the six-month LIBOR, reset semi-annually, plus a weighted average margin of 566.4 basis points. Income taxes, principally in Argentina, are expected to be approximately $2 million as the Company benefits from the carryforward of net operating losses in the United States and Canada.

Production growth. The Company expects that its annual 2003 worldwide production will be approximately 165 MBOE per day, an increase of 45 percent over 2002 levels. The growth in production during 2003 includes initial production during the second quarter from the Company's deepwater Gulf of Mexico Falcon gas project and the Sable oil project in South Africa, coupled with peak rates of production from Canyon Express and increases in production from the Company's core properties in the United States, Argentina and Canada due to an aggressive development drilling program with approximately twice as many wells anticipated in 2003 versus 2002.

Capital expenditures. During 2003, the Company's budget for oil and gas producing activities is expected to range from $450 million to $550 million, of which approximately 35 percent has been budgeted for exploration expenditures and 65 percent has been budgeted for development drilling and facility costs. The Company's 2003 capital budget is allocated approximately 60 percent to the United States, nine percent to Argentina and Canada and 22 percent to Africa. The Company's 2003 capital budget includes $35 million of remaining development capital to complete the Falcon and Devils Tower development projects in the deepwater Gulf of Mexico and the Sable oil project offshore South Africa. Aggressive development drilling programs in the Company's core Spraberry oil field, Hugoton and West Panhandle gas fields, the United States Gulf Coast, Argentina and Canada will resume with approximately twice as many wells anticipated in 2003 versus 2002. During 2003, the Company has planned exploration drilling in the Gulf of Mexico, the onshore Gulf Coast area, Alaska, Canada, Gabon, Tunisia and South Africa. During the years ended December 31, 2004 and 2005, the Company expects to expend approximately $172 million and $151 million, respectively, of capital for development drilling and facility costs related to its proved undeveloped reserves.

Critical Accounting Estimates

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 estimates, 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 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 earnings 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 earnings of future periods as a component of depletion expense. During 2002, 2001 and 2000, the Company recognized exploration, abandonment, geological and geophysical expense of $85.9 million, $127.9 million and $87.6 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 as of December 31, 2002 was based on evaluations audited by independent petroleum engineers with respect to the Company's major properties and prepared by the Company's engineers with respect to all other properties. The Company's proved reserve information included in this Report as of December 31, 2001 and 2000 was based on evaluations prepared by the Company's engineers. Estimates prepared by other third parties may be higher or lower than those included herein.

Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will 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 will increase, reducing future 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 sheets as of December 31, 2002 and 2001 reflect 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; (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. Many assumptions are utilized in the assessments that may prove to be materially incorrect in the future.

New Accounting Pronouncements

During June 2001, the Financial Accounting Standards Board ("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, asset retirement obligations 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 currentlyrecords significant asset retirement obligations through the unit-of-production method, except for such liabilities that were assumed in business combinations, which were recorded at their estimated fair values. The Company adopted the provisions of SFAS 143 on January 1, 2003.

The adoption of SFAS 143 resulted in a January 1, 2003 cumulative effect adjustment to record (i) a $13.8 million increase in the carrying values of proved properties, (ii) a $26.3 million decrease in accumulated depreciation, depletion, and amortization of property, plant and equipment, (iii) a $1.0 million increase in current abandonment liabilities and (iv) a $22.4 million increase in noncurrent abandonment liabilities. The net impact of items (i) through (iv) was to record a gain of $16.7 million, net of tax, as a cumulative effect adjustment of a change in accounting principle in the Company's consolidated statements of operations upon adoption on January 1, 2003.

During April 2002, the FASB issued Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections" ("SFAS 145"). Prior to the adoption of the provisions of SFAS 145, gains or losses on the early extinguishment of debt were required to be classified in a company's periodic consolidated statements of operations as extraordinary gains or losses, net of associated income taxes, after the determination of income or loss from continuing operations. SFAS 145 requires, except in the case of events or transactions of a highly unusual and infrequent nature, gains or losses from the early extinguishment of debt to be classified as components of a company's income or loss from continuing operations. The Company adopted the provisions of SFAS 145 on January 1, 2003. The adoption of the provisions of SFAS 145 is not expected to affect the Company's future financial position or liquidity. Upon adoption of the provisions of SFAS 145, gains or losses from the early extinguishment of debt recognized in the Company's consolidated statements of operations for the years ended December 31, 2002, 2001 and 2000 will be reclassified to other revenues or other expense and included in the determination of the income (loss) from continuing operations of those periods.

Results of Operations

Oil and gas revenues. Revenues from oil and gas operations totaled $701.8 million during 2002, as compared to $847.0 million during 2001 and $852.7 million during 2000, representing a 17 percent decrease from 2001 to 2002. The revenue decrease from 2001 to 2002 was due to year-on-year worldwide average gas, NGL and oil price declines of 23 percent, 19 percent and five percent, respectively, including the effects of gas and oil price hedges; and an eight percent decline in worldwide oil production, offset by worldwide NGL and gas production increases of four percent and two percent, respectively. The revenue decrease from 2000 to 2001 was due to a four percent decline in BOE production 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 declines in 2001 sales volumes were primarily attributable to normal well production declines.

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,		
	2002	2001	2000
Production:			
Oil (MBbls)	11,514	12,498	12,535
NGLs (MBbls)	8,086	7,800	8,379
Gas (MMcf)	131,015	127,865	135,843
Total (MBOE)	41,436	41,609	43,555
Average daily production:			
Oil (Bbls)	31,545	34,241	34,249
NGLs (Bbls)	22,154	21,370	22,894
Gas (Mcf)	358,945	350,314	371,157
Total (BOE)	113,524	113,997	119,002
Average reported prices:			
Oil (per Bbl)			
United States	$ 23.66	$ 24.34	$ 22.07
Argentina	$ 20.63	$ 23.79	$ 29.09
Canada	$ 22.26	$ 21.87	$ 27.50
Worldwide	$ 22.89	$ 24.12	$ 24.01
NGL (per Bbl)			
United States	$ 13.77	$ 16.88	$ 20.05
Argentina	$ 14.56	$ 19.29	$ 22.91
Canada	$ 16.77	$ 21.11	$ 24.32
Worldwide	$ 13.92	$ 17.14	$ 20.27
Gas (per Mcf)			
United States	$ 3.16	$ 4.10	$ 3.50
Argentina	$ .48	$ 1.31	$ 1.19
Canada	$ 2.50	$ 2.86	$ 2.88
Worldwide	$ 2.49	$ 3.23	$ 2.81
Annual percentage increase (decrease) in average worldwide reported prices:			
Oil	(5)	-	56
NGL	(19)	(15)	74
Gas	(23)	15	48

Hedging activities. The commodity 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 commodity price risk associated with certain capital projects. The effective portions of changes in the fair values of the Company's commodity price hedge derivatives are deferred as increases or decreases to stockholders' equity until the underlying hedged transaction occurs. Consequently, changes in the effective portions of commodity price hedge derivatives add volatility to the Company's reported stockholders' equity until the hedge derivative matures or is terminated. See Note J 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 2002, 2001 and 2000 from the Company's hedging activities, the Company's open hedge positions at December 31, 2002 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 $11.2 million, $21.8 million and $25.8 during 2002, 2001 and 2000, respectively. The Company's interest and other income was comprised of revenue that was not directly attributable to oil and gas producing activities or oil and gas property divestitures. See Note L 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, 2002, the Company realized $118.9 million of cash proceeds from asset divestitures and, associated therewith, recorded net gains of $4.4 million. The proceeds derived from asset divestitures during 2002 included $91.3 million from the early termination of hedge derivatives, $20.9 million from the cash settlement ofa gas balancing receivable, $4.7 million from the sale of certain gas properties located in Oklahoma and $2.0 million from the sale of other corporate assets. The Company recorded a gain of $2.8 million associated with the sale of the gas properties in Oklahoma and a gain of $1.6 million from the sale of other corporate assets. The proceeds from the early termination of hedge derivatives represent deferred hedge gains and losses that will be recognized as increases or decreases to future interest expenses or future oil and gas revenues. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the amortization of deferred hedge gains and losses.

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 $3.4 million from the sale of other corporate assets. 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, a loss of $1.1 million from the sales of oil and gas properties and a gain of $.7 million from the sale of other corporate assets.

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. The2000 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.

The net cash proceeds from asset divestitures during 2002, 2001 and 2000 were used, together with net cash flows provided by operating activities, to fund additions to oil and gas properties and to reduce outstanding indebtedness. See Note M 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 decreased in 2002 by four percent and increased in 2001 by 16 percent. 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 decrease in production costs during 2002 was primarily due to decreases in field fuel expense and production taxes as a result of lower North American average gas prices and lower Argentine lease operating expenses resulting from lower Argentine expenses on a U.S. dollar equivalent basis due to the devaluation of the Argentine peso versus the U.S. dollar, partially offset by moderately higherworkover expenses, ad valorem taxes (which are computed using prior year average annual commodity prices) and declines in the thirdparty gas processing and treating margin component of lease operating expense. The increase in production costs during 2001 was primarily due to increases in field fuel expense as a result of higher North American average gas prices, higher ad valorem taxes and to declines in the third party gas processing and treating margin component of lease operating expenses. The following table provides the components of the Company's production costs during the years ended December 31, 2002, 2001 and 2000:

	Year Ended December 31,		
	2002	2001	2000
		(per BOE)	
Lease operating expenses	$ 2.87	$ 2.76	$ 2.42
Taxes:			
Production	.54	.74	.77
Ad valorem	.54	.49	.29
Field fuel expenses	.62	.88	.71
Workover expenses	.25	.17	.15
Total production costs	$ 4.82	$ 5.04	$ 4.34

Depletion, depreciation and amortization expense. The Company's total depletion, depreciation and amortization expense per BOE was $5.22, $5.35 and $4.93 for the years ended December 31, 2002, 2001 and 2000, respectively. Depletion expense, the largest component of depletion, depreciation and amortization, was $5.01, $5.02 and $4.57 per BOE during the years ended December 31, 2002, 2001 and 2000, respectively, and depreciation and amortization of other property and equipment was $.21, $.33 and $.36 per BOE during each of the respective years. The decrease in depreciation and amortization of other property and equipment during 2002 was primarily comprised of decreases associated with fully amortized information technology assets. During 2001, the increase in per BOE depletion expense was primarily associated with decreases in United States production, which had 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.

Exploration, abandonments, geological and geophysical costs. Exploration, abandonments, geological and geophysical costs totaled $85.9 million, $127.9 million and $87.6 million for the years ended December 31, 2002, 2001 and 2000, respectively. The following table sets forth the components of the Company's 2002, 2001 and 2000 exploration and abandonments/geological and geophysical costs:

	United States	Argentina	Canada	Other Foreign	Total
			(in thousands)		
Year Ended December 31, 2002:					
Geological and geophysical costs	$ 22,761	$ 4,138	$ 3,544	$ 7,223	$ 37,666
Exploratory dry holes	32,557	3,294	1,220	(539)	36,532
Leasehold abandonments and other	7,637	2,874	1,077	108	11,696
	$ 62,955	$ 10,306	$ 5,841	$ 6,792	$ 85,894
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

The decrease in 2002 exploration, abandonments, geological and geophysical costs reflected a decline in Argentine exploration activities as the Company monitored and assessed the economic environment and risks associated with Argentina; a decline in exploratory dry holes and geological and geophysical costs in Africa, as the Company assessed its exploratory successes in Gabon and Tunisia; and the allocation of a larger percentage of the Company's 2002 capital budget to the development of its significant discoveries in the Gulf of Mexico and offshore South Africa. The increase in 2001 exploration costs, as compared to 2000, was primarily due to increased geological and geophysical costs that were supportive of exploratory drilling, increased exploratory drilling in the Gulf of Mexico and Argentina and an exploratory dry hole drilled in Tunisia. Approximately 20 percent of the Company's 2002 costs incurred for oil and gas producing activities were exploration costs as compared to 34 percent in 2001 and 38 percent in 2000.

General and administrative expenses. The Company's general and administrative expenses totaled $48.4 million ($1.17 per BOE), $37.0 million ($.89 per BOE) and $33.3 million ($.76 per BOE) during the years ended December 31, 2002, 2001 and 2000, respectively. The increase in administrative expense during 2002 as compared to 2001 was primarily due to the elimination of operating overhead being charged by the Company to the 42 affiliated partnerships that were merged into a wholly-owned subsidiary of the Company during December 2001 (see "Financial and Operating Performance" and Note D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the 2001 merger). Additionally, the Company awarded 645,445 shares of restricted stock to directors, officers and key employees as part of the Company's compensation program. The Company recorded $16.2 million of deferred compensation associated with the restricted stock awards, which amount will be amortized to compensation expense during the vesting periods of the awards. Amortization of the deferred costs of the restricted stock increased general and administrative expenses by $1.9 million in 2002. See Note G of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the restricted stock awards and their vesting periods. The increase in general and administrative expense during 2001, as compared to 2000, was primarily due to an increase in compensation expense.

Interest expense. Interest expense was $95.8 million, $132.0 million and $162.0 million for the years ended December 31, 2002, 2001 and 2000, respectively. The decline in 2002 interest expense as compared to 2001, was primarily due to incremental interest savings of $18.0 million from the Company's interest rate hedging program; a $6.3 million increase in interest capitalized; interest savings from the retirement of the Company's outstanding 11-5/8 percent and 10-5/8 percent senior subordinated notes during the third quarter of 2001 and $38.7 million of the Company's 9-5/8 percent senior notes during the fourth quarter of 2001; interest savings from the repurchase of $47.1 million of 9-5/8 percent senior notes and $13.9 million of 8-7/8 percent senior notes during 2002; interest savings from the repayment of the $45.2 million West Panhandle gas field capital obligation in July 2002 which bore interest at an annual rate of 20 percent; and interest savings from reductions in underlying market interest rates. The decrease in interest expense for 2001 as compared to 2000 was primarily due to incremental interest savings of $7.0 million from the Company's interest rate hedging program; a $6.0 million increase in interest capitalized; and interest savings associated with the redemption of the Company's outstanding 11-5/8 percent and 10-5/8 percent senior subordinated notes and $38.7 million of the Company's 9-5/8 percent senior notes.

As is discussed in "2003 Outlook" above, capitalized interest will decline during 2003, as compared to 2002 levels, primarily due to the completion of the Canyon Express development project during September 2002 and the anticipated completion of the Falcon and Sable development projects during the second quarter of 2003. Additionally, 2003 interest expense will be impacted by fair value hedges of the Company's 9-5/8 percent senior notes that were initiated by the Company during February 2003 and for which more detailed information is provided in "2003 Outlook" and in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk". See Note E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the Company's long-term debt, interest expense and extraordinary items.

Other expenses. Other expenses were $17.3 million during 2002, as compared to $39.6 million during 2001 and $67.2 million during 2000. Other expenses during 2002 were primarily comprised of a $6.9 million charge from the remeasurement of the Company's Argentine peso-denominated net monetary assets and liabilities and $2.5 million of marketing losses incurred to transport and sell purchased Canadian gas to a Chicago, Illinois sales point. See Note B and Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding currency remeasurement and gas transportation commitments.

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; $6.0 million of bad debt expense related to derivative contracts with Enron North America Corp. and $4.6 million of other expenses.

The primary component of other expense during 2000 was $58.5 million of mark-to-market losses on derivative contracts that did not qualify for hedge accounting treatment, including $43.9 million of losses on derivative contracts that matured during 2000 and $14.6 million of losses associated with the Company's Btu swap agreements that mature at the end of December 2004. During 2001, the Company entered into offsetting swap agreements that had fixed the prices that are to be received and paid by the Company under the Btu swap agreements. Consequently, the Btu swap agreements are no longer sensitive to changes in oil or gas commodity prices.

Income tax provisions (benefits). The Company recognized consolidated income tax provisions of $5.1 million and $4.0 million during 2002 and 2001, respectively, and a consolidated income tax benefit of $6.0 million during 2000. The Company's consolidated tax provision for the year ended December 31, 2002 was comprised of current U.S. state and local taxes of $.2 million, current foreign taxes of $2.1 million and deferred foreign tax provisions of $2.8 million. The Company's consolidated tax provision for the year ended December 31, 2001 was comprised of current U.S. state and local taxes of $1.1 million, current foreign taxes of $10.5 million and deferred foreign tax benefits of $7.6 million. The Company's consolidated tax benefit in 2000 was 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 certain of its net operating loss carryovers and tax credit carryovers prior to their scheduled expirations, the Company has established a valuation allowance of $277.2 million against those carryovers. Although the Company believes it is more likely than not that the carrying values of its remaining deferred tax assets will be realized through future taxable earnings or alternative tax planning strategies, 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 2003 will be minimal in the United States and Canada and approximately 35 percent in Argentina. 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 tax, deferred tax asset valuation reserves and net operating loss carryforward expirations.

Extraordinary items. During 2002, the Company repurchased $47.1 million of its 9-5/8 percent senior notes, $13.9 million of its 8-7/8 percent senior notes and repaid a $45.2 million West Panhandle field capital cost obligation. Associated with the 2002 debt extinguishments, the Company recognized an extraordinary loss, net oftaxes, of $22.3 million. During 2001, the Company redeemed the remaining $22.5 million of its outstanding 11-5/8 percent senior subordinated notes, $6.8 million of its outstanding 10-5/8 percent senior subordinated notes and repurchased $38.7 million of its 9-5/8 percent senior notes. Associated with these debt extinguishments, the Company recognized an extraordinary loss, net of taxes, of $3.8 million. During 2000, the Company replaced its prior credit facility, which was scheduled to mature in August 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. See "New Accounting Pronouncements", above, for information regarding future changes in the classification of the Company's extraordinary gains and losses.

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. Funding for exploration, development and acquisitions of oil and gas properties and repayment of contractual obligations 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. Funding for the Company's working capital obligations is provided by internally-generated cash flow.

Oil and gas properties. The Company's cash expenditures for additions to oil and gas properties during 2002, 2001 and 2000 totaled $614.7 million, $529.7 million and $299.7 million, respectively. The Company's 2002 expenditures for additions to oil and gas properties were funded by $332.2 million of net cash provided by operating activities, $118.9 million of proceeds from the disposition of assets and a portion of the proceeds from the issuance of 11.5 million shares of the Company's common stock during April 2002. 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 capital expenditures were internally funded by net cash provided by operating activities.

The Company strives to maintain its indebtedness at reasonable levels in order to provide sufficient financial flexibility to take advantage of future opportunities. The Company's capital budget for 2003 is expected to range from $450 million to $550 million. The Company believes that net cash provided by operating activities during 2003 will be sufficient to fund the 2003 capital expenditures budget.

Contractual obligations, including off-balance sheet obligations. The Company's contractual obligations include long-term debt, operating leases, Btu swap agreements, terminated commodity hedges and other contracts. From time to time, the Company enters into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations of the Company. As of December 31, 2002, the material off-balance sheet arrangements and transactions that the Company has entered into include (i) $27.2 million of undrawn letters of credit issued under the Company's $575 million corporate credit facility and (ii) operating lease agreements under which the Company's future minimum lease commitments are summarized in the table below and in Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data". 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 and gas transportation commitments. 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, 2002 and Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding gas transportation commitments. The following table summarizes the Company's payments due by period for fixed and determinable contractual obligations:

	Payments Due by Year				
	2003	2004	2005	2006-2007	Thereafter
			(in thousands)		
Long-term debt (a)	$ -	$ -	$ 406,704	$ 161,130	$ 1,100,702
Operating leases (b)	19,364	41,553	39,375	58,924	36,338
Btu swap agreements (c)	7,168	7,190	-	-	-
Terminated commodity hedges	484	340	-	-	-
	$ 27,016	$ 49,083	$ 446,079	$ 220,054	$ 1,137,040

(a) See Note E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".
(b) See Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".
(c) See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

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 2003.

Operating activities. Net cash provided by operating activities during 2002, 2001 and 2000 were $332.2 million, $475.6 million and $430.1 million, respectively. Net cash provided by operating activities in 2002 decreased by $143.4 million, or 30 percent, as compared to that of 2001. The decrease in 2002 net cash provided by operating activities was principally due to declines in commodity prices, offset partially by declines in interest expense. Net cash provided by operating activities in 2001 increased by $45.5 million, or 11 percent, as compared to that of 2000. The increase in 2001 was primarily due to higher commodity prices as compared to 2000, declines in interest expense and an increase in trade receivable collections.

Financing activities. During the year ended December 31, 2002, the Company's financing activities provided $170.9 million of cash, comprised of $236.0 million of proceeds, net of issuance costs, from the sale of 11.5 million shares of the Company's common stock; $48.0 million of net borrowings of long-term debt; and $14.4 million of proceeds from the exercise of long-term incentive plan stock options and employee stock purchases. Partially offsetting these cash proceeds from financing activities were $124.2 million of payments of noncurrent liabilities and $3.3 million of debt issuance costs during 2002. In contrast,during the years ended December 31, 2001 and 2000, the Company used $64.0 million and $244.1 million, respectively, of net cash in financing activities. During the years ended December 31, 2001 and 2000, the Company used $5.1 million and $177.3 million of cash, respectively, to repay long-term debt; $53.4 million and $29.8 million, respectively, to repay noncurrent liabilities; $13.0 million and $27.3 million, respectively, to purchase treasury stock; and, during the year ended December 31, 2000, $13.8 million for deferred loan and debt issuance costs. Partially offsetting the above described net cash uses from financing activities were $7.5 million and $4.2 million of net cash provided from the exercise of long-term incentive plan stock options and employee stock purchases during the years ended December 31, 2001 and 2000, respectively.

Over the three year period ended December 31, 2002, the Company has used $134.4 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, 2002, 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 the years ended December 31, 2002 and 2001, the Company entered into interest rate swap contracts to hedge the fair value of its 6-1/2 percent senior notes, its 8-7/8 percent senior notes and its 8-1/4 percent senior notes. The Company also entered into interest rate swaps to hedge a portion of its interest rate risk under the Credit Agreement. In 2002 and 2001, the Company terminated its open interest rate swap portfolios to lock in the substantial fair value of the derivatives. As of December 31, 2002, the Company had $35.7 million of deferred gains associated with the interest rate swap terminations recorded as an increase in the carrying value of the Company's long-term debt. During the years ended December 31, 2002, 2001 and 2000, net gains from the Company's interest rate swaps have reduced interest expense by $25.3 million, $7.3 million and $.3 million, respectively. See Note J 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 interest rate hedging activities.

As is further described in "Results of Operations" above, during the year ended December 31, 2002, the Company repurchased $47.1 million of its 9-5/8 percent senior notes, $13.9 million of its 8-7/8 percent senior notes and repaid a $45.2 million West Panhandle gas field capital cost obligation. Additionally, during the year ended December 31, 2001, the Company redeemed its remaining 11-5/8 percent and 10-5/8 percent senior subordinated notes and $38.7 million of its 9-5/8 percent senior notes.

At December 31, 2002, the Company had a $575.0 million corporate credit facility with a syndicate of banks that matures on March 1, 2005. Outstanding borrowings under the corporate credit facility totaled $260.0 million as of December 31, 2002. In addition, the Company has five outstanding senior note issuances at December 31, 2002. Such debt issuances consist of (i) $136.1 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) $339.2 million aggregate remaining principal amount of 9-5/8 percent senior notes due in 2010; (v) $150 million aggregate principal amount of 7-1/2 percent senior notes due in 2012; and (vi) $250 million aggregate principal amount of 7-1/5 percent senior notes due in 2028. Certain of the obligations above contain restrictive covenants, each of which the Company is in compliance.

The weighted average interest rate on the Company's indebtedness for the year ended December 31, 2002 was 5.74 percent as compared to 7.52 percent for the year ended December 31, 2001 and 8.68 percent for the year ended December 31, 2000, taking into account the effect of interest rate swaps. See Note E 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, 2002 and 2001.

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 2002, 2001 and 2000, proceeds from the sale of non-strategic assets totaled $118.9 million, $113.5 million and $102.7 million, respectively. The Company's 2002, 2001 and 2000 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 2002 and 2001 were used to fund a portion of the Company's 2002 and 2001 capital expenditures and for general corporate obligations. The net cash proceeds from the 2000 asset divestitures were used to reduce the Company's outstanding indebtedness (see "Results of Operations", above, and Note M of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data").

Book capitalization and liquidity. The Company's total debt was $1.67 billion as of December 31, 2002, as compared to total debt of $1.58 billion on December 31, 2001 and 2000. The Company's total book capitalization at December 31, 2002 was $3.04 billion, consisting of total debt of $1.67 billion and stockholders' equity of $1.37 billion. The Company's debt to total capitalization was 55 percent at December 31, 2002. The Company's ratio of current assets to current liabilities was .54 at December 31, 2002 and 1.12 at December 31, 2001. The decline in the Company's ratio of current assets to current liabilities was primarily due to a $170.7 million difference in the fair value of 2003 maturing derivatives at December 31, 2002 as compared to the fair value of 2002 maturing derivatives at December 31, 2001. Including $27.2 million of undrawn and outstanding letters of credit, the Company has $287.8 million of unused borrowing capacity available under its Credit Agreement as of December 31, 2002.

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, 2002 and 2001, and from which the Company may incur future gains or losses from changes in market interest rates, foreign exchange rates or commodity 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 2002. During 2002, the Company was a party to forward foreign exchange contracts, commodity and interest rate swap contracts and commodity collar contracts. See Note J 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 2002:

	Derivative Contract Assets (Liabilities)			
	Commodity	Interest Rate	Foreign Exchange Rate	Total
		(in thousands)		
Fair value of contracts outstanding as of December 31, 2001	$ 180,554	$ (19,637)	$ 61	$ 160,978
Changes in contract fair values (1)	(183,285)	62,786	203	(120,296)
Contract realizations:				
Maturities	(48,212)	(11,155)	(249)	(59,616)
Termination - cash settlements	(58,685)	(31,994)	-	(90,679)
Termination - future obligations	1,303	-	-	1,303
Termination - future receivables	(479)	-	-	(479)
Fair value of contracts outstanding as of December 31, 2002	$ (108,804)	$ -	$ 15	$(108,789)

(1) At inception, new derivative contracts entered into by the Company have no intrinsic value.

Quantitative Disclosures

Interest rate sensitivity. The following tables provide information, in U. S. dollar equivalent amounts, about other financial instruments that the Company was a party to as of December 31, 2002 and 2001 and that are or were 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 was obligated to periodically pay on the debt as of December 31, 2002 and 2001. For variable rate debt, the average interest rate represents the average rates being paid on the debt projected forward proportionate to the forward yield curves for the six-month London Interbank Offered Rate.

Interest Rate Sensitivity
Derivative and Other Financial Instruments as of December 31, 2002 (1)

	2003	2004	2005	2006	2007	Thereafter	Total	Liability Fair Value
				(in thousands except interest rates)				
Total Debt:								
U.S. dollar denominated maturities:								
Fixed rate debt	$ -	$ -	$146,704	$ -	$161,130	$1,100,702	$1,408,536	$(1,484,009)
Weighted average interest rate (%)	7.94	7.94	7.87	7.83	7.81	7.77		
Variable rate debt	$ -	$ -	$260,000	$ -	$ -	$ -	$ 260,000	$ (260,000)
Average interest rate (%) ..	2.89	4.08	5.27					

(1) During February 2003, the Company entered into interest rate swap contracts to hedge a portion of the fair value of its 9-5/8 percent senior notes. Under the terms of the interest rate swap contracts, the Company will receive a fixed annual rate of 9-5/8 percent on $250 million notional amount and will pay the counterparties a variable rate on the notional amount equal to the six-month LIBOR, reset semi-annually, plus a weighted average margin of 566.4 basis points.

The accompanying Interest Rate Sensitivity table as of December 31, 2001 also provides information about interest rate swap agreements that the Company was a party to as of that date. These interest rate swap agreements were terminated during the year ended December 31, 2002 and no longer represent market risk to the Company. The interest rate swap agreements as of December 31, 2001 hedged (i) the fair value of the Company's 8-1/4 percent senior notes; (ii) the fair value of the Company's 6-1/2 percent senior notes; and (iii) a portion of the interest rate risk associated with the Company's Credit Agreement.

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

	2002	2003	2004	2005	2006	Thereafter	Total	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:								
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							

Foreign exchange rate 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, 2002 and 2001 and that were sensitive to changes in foreign exchange rates.

Foreign Exchange Rate Sensitivity
Derivative and Other Financial Instruments as of December 31, 2002

	2003	Total	Asset Fair Value (1)
	(in thousands except interest rates)		
Foreign Exchange Rate Hedge Derivatives:			
Notional amount of foreign currency forward contracts	$ 2,000	$ 2,000	$ 15
Fixed Canadian to U.S. dollar rate paid	.6258		

(1) The Company's foreign currency forward contract matured as a $15 thousand asset during January 2003.

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, 2002 and 2001 and that were sensitive to changes in oil and gas prices. As of December 31, 2002 and 2001, all of the Company's derivative financial instruments that were sensitive to changes in oil and gas prices qualified 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.

See Notes B, C and J 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 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, 2002

	2003	2004	Liability Fair Value
Oil Hedge Derivatives (1):			
Average daily notional Bbl volumes:			
Swap contracts (2)	22,236	14,000	$ (19,912)
Weighted average fixed price per Bbl	$ 24.45	$ 23.11	
Average forward NYMEX oil prices per Bbl (3)	$ 31.55	$ 25.75	

(1) See Note J 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 2003 and 2004.
(2) During January 2003, the Company increased its 2003 oil hedge positions by entering into 6,000 Bbls per day of March 2003 oil swap contracts with average per Bbl fixed prices of $33.51.
(3) The average forward NYMEX oil prices per Bbl are based on February 18, 2003 market quotes.

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

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

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

Gas Price Sensitivity
Derivative Financial Instruments as of December 31, 2002

	2003	2004	2005	2006 & 2007	Liability Fair Value
Gas Hedge Derivatives (1) (2):					
Average daily notional MMBtu volumes:					
Swap contracts	230,000	180,000	10,000	20,000	$ (88,892)
Weighted average fixed price per MMBtu	$ 3.76	$ 3.81	$ 3.70	$ 3.75	
Average forward NYMEX gas prices per MMBtu (3)	$ 5.53	$ 4.80	$ 4.31	$ 4.12	

(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 J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for hedge volumes and weighted average prices per MMBtu by calendar quarter for 2003, 2004, 2005, 2006 and 2007.

(3) The average forward NYMEX gas prices per MMBtu are based on February 18, 2003 market quotes.

Gas Price Sensitivity
Derivative Financial Instruments as of December 31, 2001

	2002	2003	2004	2005	Asset Fair Value
Gas Hedge Derivatives (1) (2):					
Average daily notional MMBtu volumes:					
Swap contracts	165,205	117,500	165,000	50,000	$ 137,606
Weighted average fixed price per MMBtu	$ 4.19	$ 3.62	$ 3.84	$ 3.63	
Collar contracts	20,000				$ 14,019
Weighted average short call ceiling price per MMBtu	$ 6.00				
Weighted average long put floor price per MMBtu	$ 4.50				
Average forward NYMEX gas prices per MMBtu (2)	$ 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) The average forward NYMEX gas prices per MMBtu are based on February 28, 2002 market quotes.

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 E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a discussion of the Company's debt instruments.

Derivative financial instruments. The Company has, from time to time, entered into interest rate, foreign exchange rate and commodity price derivative contracts to hedge interest rate, foreign exchange rate and commodity price risks in accordance with policies and guidelines approved by the Company's board of directors. In accordance with those policies and guidelines, the Company's executive management determines the appropriate timing and extent of hedge transactions. 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, 2002, 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 vis á vis 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, 2002.

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, 2002 and 2001, 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, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Pioneer Natural Resources Company at December 31, 2002 and 2001, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 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 24, 2003

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

ASSETS

	December 31, 2002	December 31, 2001
Current assets:		
Cash and cash equivalents	$ 8,490	$ 14,334
Accounts receivable:		
Trade, net of reserves for doubtful accounts of $4,744 and $5,553 as of December 31, 2002 and 2001, respectively	97,774	81,616
Affiliates	448	595
Inventories	10,648	14,549
Deferred income taxes	13,900	6,400
Other current assets:		
Derivative assets, net of valuation reserves of $3,351 and $3,153 as of December 31, 2002 and 2001, respectively	3,150	127,074
Other	12,683	11,075
Total current assets	147,093	255,643
Property, plant and equipment, at cost:		
Oil and gas properties, using the successful efforts method of accounting:		
Proved properties	4,252,897	3,691,783
Unproved properties	219,073	187,785
Accumulated depletion, depreciation and amortization	(1,303,541)	(1,095,310)
	3,168,429	2,784,258
Deferred income taxes	76,840	84,319
Other property and equipment, net	22,784	21,560
Other assets, net:		
Derivative assets, net of valuation reserves of $1,136 and $1,069 as of December 31, 2002 and 2001, respectively	793	54,486
Other	39,177	70,787
	$ 3,455,116	$ 3,271,053

LIABILITIES AND STOCKHOLDERS' EQUITY

	December 31, 2002	December 31, 2001
Current liabilities:		
Accounts payable:		
Trade	$ 117,582	$ 92,760
Affiliates	7,192	6,405
Interest payable	37,458	37,410
Other current liabilities:		
Derivative obligations	83,638	36,830
Other	28,722	54,804
Total current liabilities	274,592	228,209
Long-term debt	1,668,536	1,577,304
Noncurrent derivative obligations	42,490	32,438
Other noncurrent liabilities	85,841	133,945
Deferred income taxes	8,760	13,768
Stockholders' equity:		
Preferred stock, $.01 par value; 100,000,000 shares authorized; zero and one share issued and outstanding as of December 31, 2002 and 2001, respectively	-	-
Common stock, $.01 par value; 500,000,000 shares authorized; 119,592,344 shares issued at December 31, 2002; and 107,422,467 shares issued at December 31, 2001	1,196	1,074
Additional paid-in capital	2,714,567	2,462,272
Treasury stock, at cost; 2,339,806 shares at December 31, 2002 and 3,486,073 shares at December 31, 2001	(32,219)	(48,002)
Deferred compensation	(14,292)	-
Accumulated deficit	(1,298,440)	(1,323,343)
Accumulated other comprehensive income:		
Deferred hedge gains, net	9,555	201,046
Cumulative translation adjustment	(5,470)	(7,658)
Total stockholders' equity	1,374,897	1,285,389
Commitments and contingencies		
	$ 3,455,116	$ 3,271,053

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,		
	2002	2001	2000
Revenues and other income:			
Oil and gas	$ 701,780	$ 847,022	$ 852,738
Interest and other	11,222	21,778	25,775
Gain on disposition of assets, net	4,432	7,681	34,184
	717,434	876,481	912,697
Costs and expenses:			
Oil and gas production	199,570	209,664	189,265
Depletion, depreciation and amortization	216,375	222,632	214,938
Exploration and abandonments	85,894	127,906	87,550
General and administrative	48,402	36,968	33,262
Interest	95,815	131,958	161,952
Other	17,256	39,588	67,231
	663,312	768,716	754,198
Income before income taxes and extraordinary items	54,122	107,765	158,499
Income tax benefit (provision)	(5,063)	(4,016)	6,000
Income before extraordinary items	49,059	103,749	164,499
Extraordinary items - loss on early extinguishment of debt, net of tax	(22,346)	(3,753)	(12,318)
Net income	$ 26,713	$ 99,996	$ 152,181
Income per share:			
Basic:			
Income before extraordinary items	$ .44	$ 1.05	$ 1.65
Extraordinary items	(.20)	(.04)	(.12)
Net income	$ .24	$ 1.01	$ 1.53
Diluted:			
Income before extraordinary items	$ .43	$ 1.04	$ 1.65
Extraordinary items	(.20)	(.04)	(.12)
Net income	$ .23	$ 1.00	$ 1.53
Weighted average shares outstanding:			
Basic	112,542	98,529	99,378
Diluted	114,288	99,714	99,763

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	Deferred Compensation	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 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
Issuance of common stock	115	235,885	-	-	-	-	-	-	236,000
Adjustment to common stock issued for 2001 partnership acquisitions	-	(175)	-	-	-	-	-	-	(175)
Exercise of stock options and employee stock purchases	-	416	15,783	-	(1,810)	-	-	-	14,389
Deferred compensation:									
Compensation deferred	7	16,169	-	(16,176)	-	-	-	-	-
Deferred compensation included in net income	-	-	-	1,884	-	-	-	-	1,884
Net income	-	-	-	-	26,713	-	-	-	26,713
Other comprehensive income (loss):									
Deferred hedge gains and losses, net of tax:									
Deferred hedge losses	-	-	-	-	-	(179,067)	-	-	(179,067)
Net gains included in net income	-	-	-	-	-	(12,424)	-	-	(12,424)
Currency translation adjustment	-	-	-	-	-	-	-	2,188	2,188
Balance at December 31, 2002	$ 1,196	$ 2,714,567	$ (32,219)	$ (14,292)	$ (1,298,440)	$ 9,555	$ -	$ (5,470)	$ 1,374,897

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,		
	2002	2001	2000
Cash flows from operating activities:			
Net income	$ 26,713	$ 99,996	$ 152,181
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation and amortization	216,375	222,632	214,938
Exploration expenses, including dry holes	64,617	103,595	66,959
Deferred income taxes	2,788	(7,649)	(10,600)
Gain on disposition of assets, net	(4,432)	(7,681)	(34,184)
Loss on early extinguishment of debt, net of tax	22,346	3,753	12,318
Interest related amortization	(5,809)	8,689	12,699
Commodity hedge related amortization	26,490	6,199	-
Other noncash items	9,301	14,944	59,776
Change in operating assets and liabilities, net of effects from acquisitions:			
Accounts receivable	(23,922)	41,295	(7,486)
Inventory	3,023	(4,256)	(2,789)
Other current assets	(1,836)	(6,304)	(9,896)
Accounts payable	(342)	(541)	26,260
Interest payable	48	(733)	2,097
Other current liabilities	(3,115)	1,661	(52,177)
Net cash provided by operating activities	332,245	475,600	430,096
Cash flows from investing activities:			
Cash acquired in acquisitions, net of fees paid	-	11,119	-
Proceeds from disposition of assets	118,850	113,453	102,736
Additions to oil and gas properties	(614,698)	(529,723)	(299,682)
Other property dispositions (additions), net	(12,283)	(17,590)	2,445
Net cash used in investing activities	(508,131)	(422,741)	(194,501)
Cash flows from financing activities:			
Borrowings under long-term debt	529,805	328,331	922,607
Principal payments on long-term debt	(481,783)	(333,410)	(1,099,935)
Common stock issuance proceeds, net of issuance costs	236,000	-	-
Payments of other noncurrent liabilities	(124,245)	(53,437)	(29,759)
Exercise of stock options and employee stock purchases	14,389	7,504	4,164
Purchase of treasury stock	-	(13,028)	(27,298)
Deferred loan fees/issuance costs	(3,293)	-	(13,847)
Net cash provided by (used in) financing activities	170,873	(64,040)	(244,068)
Net decrease in cash and cash equivalents	(5,013)	(11,181)	(8,473)
Effect of exchange rate changes on cash and cash equivalents	(831)	(644)	(156)
Cash and cash equivalents, beginning of year	14,334	26,159	34,788
Cash and cash equivalents, end of year	$ 8,490	$ 14,334	$ 26,159

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,		
	2002	2001	2000
Net income	$ 26,713	$ 99,996	$ 152,181
Other comprehensive income (loss):			
Deferred hedge gains and losses, net of tax:			
Transition adjustment	-	(197,444)	-
Deferred hedge gains (losses)	(179,067)	393,004	-
Net (gains) losses included in net income	(12,424)	5,486	-
Gains and losses on available for sale securities:			
Unrealized holding gains (losses)	-	(45)	33,828
Gains included in net income	-	(8,109)	(25,674)
Currency translation adjustment	2,188	(11,173)	(6,910)
Other comprehensive income (loss)	(189,303)	181,719	1,244
Comprehensive income (loss)	$ (162,590)	$ 281,715	$ 153,425

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. The Company is an oil and gas exploration and production company with ownership interests in oil and gas properties located in the United States, 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. As of December 31, 2002, the Company had $.2 million of trading securities recorded to other assets. The Company had no investments in trading securities as of December 31, 2001.

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, 2002 or 2001.

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, 2002 or 2001.

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 had existed for many years. The following bullet points disclose the significant Argentine assumptions utilized in the preparation of the 2002 and 2001 financial statements:

- As of December 31, 2002 and 2001, the Company used exchange rates of 3.37 pesos to $1 and 1.7 pesos to $1, respectively, to remeasure the peso-denominated monetary assets and liabilities of the Company's Argentine subsidiaries.

- As part of the December 31, 2001 remeasurement process, the Company estimated that the recovery or settlement values to be realized on pre-devaluation, 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 lower than the Company's carrying cost on an equivalent U.S. dollar basis as of December 31, 2001.

- The Company reviewed its Argentine proved and unproved properties for impairment as of December 31, 2002 and 2001. The Company's assessments were based on the Company's expectations offuture commodity prices to be received and expenses to be paid in Argentina. The December 31, 2002 assumptions utilized to determine future net cash flows had oil and natural gas liquids ("NGLs") prices at world market prices adjusted for export taxes and local market discounts. Gas prices were assumed to return to predevaluation U.S. dollar levels after a period of time to allow for inflation. Expenses were initially assumed to be equivalent to reported expenses in 2002, but to gradually increase to 15 percent above 2002 levels. 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 of the Company's Argentine subsidiaries as of December 31, 2002 resulted in the Company recognizing a $6.9 million charge during 2002. The December 31, 2001 remeasurement of the Company's Argentine subsidiaries' peso-denominated monetary net assets and the adjustment to reduce the subsidiaries' carrying values 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; (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.

New accounting pronouncements. During June 2001, the Financial Accounting Standards Board ("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, asset retirement obligations 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 that were assumed in business combinations, which were recorded at their estimated fair values. The Company adopted the provisions of SFAS 143 on January 1, 2003.

The adoption of SFAS 143 resulted in a January 1, 2003 cumulative effect adjustment to record (i) a $13.8 million increase in the carrying values of proved properties, (ii) a $26.3 million decrease in accumulated depreciation, depletion, and amortization of property, plant and equipment, (iii) a $1.0 million increase in current abandonment liabilities and (iv) a $22.4 million increase in noncurrent abandonment liabilities. The net impact of items (i) through (iv) was to record a gain of $16.7 million, net of tax, as a cumulative effect adjustment of a change in accounting principle in the Company's consolidated statements of operations upon adoption on January 1, 2003.

During April 2002, the FASB issued Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections" ("SFAS 145"). Prior to the adoption of the provisions of SFAS 145, gains or losses on the early extinguishment of debt were required to be classified in a company's periodic consolidated statements of operations as extraordinary gains or losses, net of associated income taxes, after the determination of income or loss from continuing operations. SFAS 145 requires, except in the case of events or transactions of a highly unusual and infrequent nature, gains or losses from the early extinguishment of debt to be classified as components of a company's income or loss from continuing operations. The Company adopted the provisions of SFAS 145 on January 1, 2003. The adoption of the provisions of SFAS 145 is not expected to affect the Company's future financial position or liquidity. Upon adoption of the provisions of SFAS 145, gains or losses from the early extinguishment of debt recognized in the Company's consolidated statements of operations for the years ended December 31, 2002, 2001 and 2000 will be reclassified to other revenues or other expense and included in the determination of the income (loss) from continuing operations of those periods.

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. The Company has established lower of cost or market allowances to reduce the carrying values of its equipment inventories in the amounts of $3.6 million and $6.8 million as of December 31, 2002 and 2001, respectively.

Inventories - commodities. Commodities are carried at the lower of average cost or market. When sold from inventory, commodities are removed 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 11 natural gas processing plants and five treating facilities. The Company operates seven of the plants and all five 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, 2002, 2001 and 2000 were $28.4 million, $32.7 million and $36.3 million, respectively. The third party expenses attributable to the plants and treating facilities for those same periods were $9.3 million, $9.7 million and $9.0 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. 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 completed and proved reserves are established or, if unsuccessful, 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, 2002 and 2001, the Company has recognized plugging and abandonment liabilities of $34.7 million and $39.5 million, respectively. See "New accounting pronouncements" for a discussion of the provisions of SFAS 143 that will be adopted by the Company on January 1, 2003.

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, if any, 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 Company's entitlement assets and entitlement liabilities and their associated volumes as of December 31, 2002 and 2001 (in millions):

	December 31,			
	2002		2001	
	Amount	MMcf	Amount	MMcf
Entitlement assets	$ 9.7	4,240	$ 30.9	25,335
Entitlement liabilities	$ 15.1	14,302	$ 20.3	15,197

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 were classified as components of the commodity prices, interest or foreign exchange rates that the derivative instrument hedged. Derivative instruments that were not hedges were recorded at fair value, as assets or liabilities. Changes in the fair values of non-hedge derivative instruments were recognized as other income or other expense during the periods in which their fair values changed.

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 adjustedto 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 Accumulated other comprehensive income ("AOCI") - deferred hedge gains, net in the stockholders' equity section of the Company's Consolidated Balance Sheets 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) on 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 expectation of hedge effectiveness must be supported by matching the essential terms of the hedged asset, liability or forecasted transaction to the derivative hedge contract or by effectiveness assessments using statistical measurements. The Company's policy is to assess actual hedge effectiveness at the end of each calendar quarter.

See Note J for a description of the specific types of derivative transactions in which the Company participates.

Stock-based compensation. The Company has a long-term incentive plan (the "Long-Term Incentive Plan") under which the Company grants stock-based compensation. The Long-Term Incentive Plan is described more fully in Note G. The Company accounts for stock-based compensation granted under the Long-Term Incentive Plan using the intrinsic value method prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB 25") and related interpretations. Stock-based compensation expenses were not recognized in net income, as all options granted under the Long-Term Incentive Plan had exercise prices equal to the market value of the underlying common stock on the dates of grant. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" ("SFAS 123") to stock-based employee compensation:

	Year ended December 31,		
	2002	2001	2000
	(in thousands, except per share amounts)		
Net income, as reported	$ 26,713	$ 99,996	$ 152,181
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(9,807)	(6,533)	(4,163)
Pro forma net income	$ 16,906	$ 93,463	$ 148,018
Net income per share:			
Basic - as reported	$ .24	$ 1.01	$ 1.53
Basic - pro forma	$ .15	$ .95	$ 1.49
Diluted - as reported	$ .23	$ 1.00	$ 1.53
Diluted - pro forma	$ .15	$ .94	$ 1.48

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 assets 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 to translate the financial statements of the Company's Canadian subsidiary in the preparation of these consolidated financial statements appear below:

	December 31, 2002	December 31, 2001	December 31, 2000
Translation:			
U.S. Dollar from Canadian Dollar - Balance Sheets	.6362	.6277	.6671
U.S. Dollar from Canadian Dollar - Statements of Operations	.6371	.6356	.6650

Reclassifications. Certain reclassifications have been made to the 2001 and 2000 amounts to conform to the 2002 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, 2002 and 2001:

	2002 Carrying Value	2002 Fair Value	2001 Carrying Value	2001 Fair Value
	(in thousands)			
Derivative contract assets (liabilities):				
Commodity price hedges	$ (108,837)	$ (108,837)	$ 151,290	$ 151,290
Btu swap contracts	$ (13,363)	$ (13,363)	$ (19,422)	$ (19,422)
Interest rate swaps	$ -	$ -	$ (19,637)	$ (19,637)
Foreign currency contracts	$ 15	$ 15	$ 61	$ 61
Financial assets:				
Trading securities	$ 236	$ 236	$ -	$ -
5-1/2% note receivable due 2008	$ 2,247	$ 2,283	$ -	$ -
Financial liabilities - long-term debt:				
Line of credit	$ (260,000)	$ (260,000)	$ (294,000)	$ (294,000)
8-7/8% senior notes due 2005	$ (146,704)	$ (147,318)	$ (161,998)	$ (159,000)
8-1/4% senior notes due 2007	$ (161,130)	$ (164,925)	$ (153,672)	$ (154,215)
6-1/2% senior notes due 2008	$ (362,592)	$ (359,205)	$ (332,613)	$ (329,280)
9-5/8% senior notes due 2010	$ (338,197)	$ (406,901)	$ (385,110)	$ (421,508)
7-1/2% senior notes due 2012	$ (150,000)	$ (160,635)	$ -	$ -
7-1/5% senior notes due 2028	$ (249,913)	$ (245,025)	$ (249,911)	$ (204,175)

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.

Commodity price swap and collar contracts, interest rate swaps and foreign currency swap contracts. The fair value of commodity price swap and collar contracts, interest rate swaps and foreign currency 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. During the year ended December 31, 2002, the Company terminated all of its interest rate swaps and the Company's foreign currency contracts matured. See Note J 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.

Financial assets. As of December 31, 2002, the Company had an investment in bonds that were classified as trading securities and a note receivable. The Company divested the bonds during January 2003. The fair value of the 5-1/2 percent note receivable was determined based on underlying market rates of interest.

Long-term debt. The carrying amount of borrowings outstanding under the Company's corporate credit facility approximates fair value because these instruments bear interest at variable market rates. The fair values of each of the senior note issuances were determined based on quoted market prices for each of the issues. See Note E for additional information regarding the Company's long-term debt.

NOTE D. Acquisitions

Falcon acquisitions. During the year ended December 31, 2002, the Company purchased, through two transactions, an additional 30 percent working interest in the Falcon field development and a 25 percent working interest in associated acreage in the deepwater Gulf of Mexico for a combined purchase price of $61.1 million. As a result of these transactions, the Company owns a 75 percent working interest in and operates the Falcon field development and related exploration blocks.

West Panhandle acquisitions. During July 2002, the Company completed the purchase of the remaining 23 percent of the rights that the Company did not already own in its core area West Panhandle gas field, 100 percent of the West Panhandle reserves attributable to field fuel, 100 percent of the related West Panhandle field gathering system and ten blocks surrounding the Company's deepwater Gulf of Mexico Falcon discovery. In connection with these transactions, the Company recorded $100.4 million to proved oil and gas properties, $3.8 million to unproved oil and gas properties and $1.9 million to assets held for resale; retired a capital cost obligation for $60.8 million; settled a $20.9 million gas balancing receivable; assumed trade and environmental obligations amounting to $5.8 million in the aggregate; and paid $140.2 million of cash. The capital cost obligation retired by the Company for $60.8 million represented an obligation for West Panhandle gas field capital additions that was not able to be prepaid and bore interest at an annual rate of 20 percent. The portion of the purchase price allocated to the retirement of the capital cost obligation was based on a discounted cash flow analysis using a market discount rate for obligations with similar terms. The capital cost obligation had a carrying value of $45.2 million, resulting in an extraordinary loss of $15.6 million from the early extinguishment of this obligation.

Affiliated partnership mergers. During 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 Natural Resources USA, Inc. ("Pioneer USA"), a wholly-owned subsidiary of the Company, 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 5.7 million shares of the Company's common stock valued at $18.35 per share. In connection with this transaction, the Company recorded $92.9 million to proved oil and gas properties, $13.6 million to cash and $.3 million to 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.

During 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 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.

Other acquisitions. During the year ended December 31, 2002, in addition to the Falcon and West Panhandle acquisitions referred to above, the Company spent approximately $25.5 million to acquire additional unproved acreage in the United States, including 34 Gulf of Mexico shelf blocks, six deepwater Gulf of Mexico blocks, a 70 percent working interest in ten state leases on Alaska's North Slope and property interests in other areas of the United States. Also during 2002, the Company acquired unproved and proved oil and gas property interests in Canada for 2.3 million and $.5 million, respectively, and $1.8 million of additional unproved property interests in Tunisia. During 2001, the Company spent $77.9 million 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 deepwater 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 spent $65.0 million to acquire additional working interests in the United States Gulf of Mexico discovery at Devils Tower and the Chinchaga gas field in Canada, an interest in the Camden Hills deepwater Gulf of Mexico discovery and the Canyon Express gathering system.

NOTE E. Long-term Debt

Long-term debt, including the effects of fair value hedges and discounts, consisted of the following components at December 31, 2002 and 2001:

	December 31,	
	2002	2001
	(in thousands)	
Line of credit	$ 260,000	$ 294,000
8-7/8% senior notes due 2005	146,704	161,998
8-1/4% senior notes due 2007	161,130	153,672
6-1/2% senior notes due 2008	362,592	332,613
9-5/8% senior notes due 2010	338,197	385,110
7-1/2% senior notes due 2012	150,000	-
7-1/5% senior notes due 2028	249,913	249,911
	$ 1,668,536	$ 1,577,304

Maturities of long-term debt at December 31, 2002 are as follows (in thousands):

2003 and 2004	$ -
2005	$ 406,704
2006	$ -
2007	$ 161,130
Thereafter	$ 1,100,702

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 (4.25 percent at December 31, 2002) 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 (1.16 percent at December 31, 2002), 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") (1.38 percent at December 31, 2002 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 rating 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 charges and expenses (the "Total Leverage Ratio"). As of December 31, 2002, the Eurodollar Margin was 137.5 basis points.

The Credit Agreement imposes certain restrictive covenants on the Company, including the maintenance of a Total Leverage Ratio not to exceed 3.75 to 1.00; 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 was in compliance with all of its debt covenants as of December 31, 2002.

As of December 31, 2002 and 2001, the Company had $27.2 million and $27.9 million of undrawn letters of credit issued under the Credit Agreement, respectively, and unused Credit Agreement borrowing capacity of$287.8 million and $253.1 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. Interest on the Company's senior notes is payable semiannually. Pioneer USA has fully and unconditionally guaranteed the senior note issuances. See Note R for a discussion of Pioneer USA debt guarantees and Consolidating Financial Statements.

During April 2002, the Company issued $150.0 million of 7-1/2 percent senior notes due April 15, 2012 (the "7-1/2 percent senior notes"). The 7-1/2 percent senior notes were issued at a price equal to 100 percent of their principal amount and resulted in net proceeds to the Company, after underwriting discounts, commissions and costs of issuance, of $146.7 million. The net proceeds from the issuance of the 7-1/2 percent senior notes were used to reduce outstanding borrowings under the Credit Agreement. The 7-1/2 percent senior notes and 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 in compliance with all of its senior note covenants as of December 31, 2002.

Early extinguishment of debt and capital cost obligation. During the year ended December 31, 2002, the Company repurchased $47.1 million of its outstanding 9-5/8 percent senior notes, $13.9 million of its outstanding 8-7/8 percent senior notes and repaid a $45.2 million capital cost obligation. The Company recognized extraordinary losses, net of taxes, of $6.7 million and $15.6 million associated with these debt extinguishments, respectively. See Note D for additional information regarding the capital cost obligation that was repaid during the year ended December 31, 2002.

During 2001, the Company redeemed the remaining $22.5 million of outstanding 11-5/8 percent senior subordinated discount notes and $6.8 million of outstanding 10-5/8 percent senior subordinated notes. Additionally, the Company repurchased $38.7 million of its 9-5/8 percent senior notes during 2001. Associated with these debt extinguishments, 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.

See Note B for a discussion of the classification of gains and losses on the early extinguishment of debt after the adoption of SFAS 145 on January 1, 2003.

Interest expense. The following amounts have been incurred and charged to interest expense for the years ended December 31, 2002, 2001 and 2000:

	Year ended December 31,		
	2002	2001	2000
		(in thousands)	
Cash payments for interest	$ 113,827	$ 129,992	$ 147,156
Accretion/amortization of discounts or premiums on loans	5,488	7,937	7,995
Amortization of deferred hedge gains (see Note J)	(14,108)	(2,750)	-
Amortization of capitalized loan fees	2,436	2,252	2,769
Kansas ad valorem tax (see Note I)	375	1,250	1,935
Net change in accruals	48	(732)	2,097
Interest incurred	108,066	137,949	161,952
Less interest capitalized	(12,251)	(5,991)	-
Interest expense	$ 95,815	$ 131,958	$ 161,952

NOTE F. Related Party Transactions

Activities with affiliated partnerships. Prior to 1992, the Company, through its wholly-owned subsidiaries, sponsored 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. During 2001, the Company completed the merger of 42 of the limited partnerships into Pioneer USA. During 2000, the Company completed the merger of the 13 employee partnerships into Pioneer USA. See Note D for additional information regarding the mergers.

During 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 drilled in those years. 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 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, 2002, 2001 and 2000:

	2002	2001	2000
		(in thousands)	
Receipt of lease operating and supervision charges in accordance with standard industry operating agreements	$ 1,495	$ 9,281	$ 9,222
Reimbursement of general and administrative expenses	$ 127	$ 1,265	$ 1,550

NOTE G. 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 $805 thousand, $652 thousand and $611 thousand for 2002, 2001 and 2000, respectively.

401(k) plan. The Pioneer Natural Resources USA, Inc. 401(k) and Matching Plan (the "401(k) Plan") is a defined contribution plan established under the Internal Revenue Code Section 401. The 401(k) Plan was formed by the merger of the Pioneer Natural Resources USA, Inc. 401(k) Plan and the Pioneer Natural Resources USA, Inc. Matching Plan on January 1, 2002. 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. Matching contributions are made to the 401(k) Plan 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 the participant's contributions, their Matching Contributions and allocations of the 401(k) Plan's earnings. Participants are fully vested in their account balances except for Matching Contributions and their proportionate share of 401(k) Plan earnings attributable to Matching Contributions, which proportionately vest over a four year period that begins with the participant's date of hire. During the years ended December 31, 2002, 2001 and 2000, the Company recognized compensation expense of $4.1 million, $3.4 million and $3.4 million, respectively, as a result of Matching Contributions.

Long-Term Incentive Plan

In August 1997, the Company's stockholders approved 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, 2002 and 2001:

	December 31,	
	2002	2001
Shares outstanding	117,252,538	103,936,394
Outstanding exercisable options or exercisable within 60 days	5,024,173	4,658,155
	122,276,711	108,594,549
Maximum shares/options allowed under the Long-Term Incentive Plan	12,227,671	10,859,455
Less: Outstanding awards under Long-Term Incentive Plan	(7,432,414)	(6,377,520)
Outstanding options under predecessor incentive plans	(488,671)	(548,551)
Shares/options available for future grant	4,306,586	3,933,384

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 (i) 100 percent restricted stock, (ii) 100 percent stock options, (iii) 100 percent cash, or (iv) a combination of 50/50 of any two, 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 overan 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 1,643,212; 1,627,071 and 1,439,035 options under the Long-Term Incentive Plan during 2002, 2001 and 2000, respectively.

Restricted stock awards. During the year ended December 31, 2002, the Company issued 654,445 restricted shares of the Company's common stock. The restricted awards wereissued as compensation to directors, officers and key employees of the Company. The restricted share awards include 18,545 shares that were granted to directors of the Company on May 13, 2002. Director awards for 3,302 shares vest on a quarterly pro-rata basis during the year ended May 13, 2003 and director awards for 15,243 shares vest on May 13, 2005. The remaining 635,900 restricted shares were awarded to officers and key employees of the Company on August 12, 2002 and vest on August 12, 2005. The Company recorded $16.2 million of deferred compensation in the stockholder's equity section of the accompanying Consolidated Balance Sheet associated with the restricted stock awards, which amount will be amortized to compensation expense over the vesting periods of the awards. During the year ended December 31, 2002, amortization of the restricted stock awards increased the Company's compensation expense by $1.9 million.

The following table reflects the outstanding restricted stock awards and activity related thereto for 2002:

	For the Year Ended December 31, 2002	
	Number of Shares	Weighted Average Price
Restricted Stock Awards:		
Restricted shares outstanding at beginning of year	-	$ -
Shares granted	654,445	$ 24.72
Lapse of restrictions	(1,652)	$ 24.60
Restricted shares outstanding at end of year	652,793	$ 24.72

There were no restricted stock awards to directors or employees during the years ended December 31, 2001 and 2000.

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 and net income per share would have been less than reported amounts. See Note B comparisons of net income and net income per share as reported and as adjusted for the pro forma effects of determining compensation expense in accordance with SFAS 123.

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 2002, 2001 and 2000:

	For the Year Ended December 31,		
	2002	2001	2000
Risk-free interest rate	2.80%	4.13%	5.66%
Expected life	5 years	5 years	5 years
Expected volatility	45%	49%	50%
Expected dividend yield	-	-	-

A summary of the Company's stock option plans as of December 31, 2002, 2001 and 2000, and changes during the years ended on those dates, are presented below:

	For the Year Ended December 31, 2002		For the Year Ended December 31, 2001		For the Year Ended December 31, 2000	
	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 ...	6,926,071	$ 18.16	6,510,559	$ 18.10	6,241,889	$ 19.45
Options granted	1,643,212	$ 21.14	1,627,071	$ 18.29	1,439,035	$ 10.32
Options forfeited	(154,717)	$ 26.27	(566,189)	$ 25.83	(798,058)	$ 18.05
Options exercised	(1,146,274)	$ 12.19	(645,370)	$ 11.14	(372,307)	$ 10.78
Outstanding, end of year	7,268,292	$ 19.60	6,926,071	$ 18.16	6,510,559	$ 18.10
Exercisable at end of year	4,269,659	$ 20.15	4,005,762	$ 20.82	3,897,187	$ 23.47
Weighted average fair value of options granted during the year	$ 8.87		$ 8.65		$ 4.88	

The following table summarizes information about the Company's stock options outstanding at December 31, 2002:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at December 31, 2002	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at December 31, 2002	Weighted Average Exercise Price
$ 5-11	800,715	3.9 years	$ 8.35	619,504	$ 8.49
$ 12-18	3,805,527	4.9 years	$ 16.69	1,714,584	$ 15.42
$ 19-26	1,288,548	4.9 years	$ 24.13	562,069	$ 23.44
$ 27-30	1,323,242	1.1 years	$ 29.59	1,323,242	$ 29.59
$ 31-52	50,260	2.6 years	$ 39.88	50,260	$ 39.88
	7,268,292			4,269,659	

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 H. Issuance of Common Stock

During April 2002, the Company completed a public offering of 11.5 million shares of its common stock at $21.50 per share. Associated therewith, the Company received $236.0 million of net proceeds after the payment of issuance costs. The Company used the net proceeds from the public offering to fund the acquisition of the Falcon assets and associated acreage in the deepwater Gulf of Mexico and the West Panhandle gas field acquisitions. See Note D for information regarding these acquisitions.

NOTE I. 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 $18.2 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.

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. Oral arguments were heard by the court in April 2002, and although the court has not yet entered a judgment or findings, it could do so at any time. 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. Although the amount of any resulting liability could have a material adverse effect on the Company's results of operations for the quarterly reporting period in which such liability is recorded, 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 annual 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, one of the Company's predecessor entities 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 $30.2 million were made against the Company. Through December 31, 2002, the Company has settled $21.7 million of the original claim amounts, of which $11.8 million was settled during 2002. The carrying value of the obligation settled during 2002 exceeded the settlement paid by the Company by $3.5 million. Accordingly, the Company recognized other income of $3.5 million during 2002. As of December 31, 2002 and December 31, 2001, the Company had on deposit $10.6 million and $24.5 million, respectively, including accrued interest, in an escrow account and had corresponding obligations for the remaining claims recorded in other current liabilities in the accompanying Consolidated Balance Sheets. The Company believes that the escrowed amounts, plus accrued interest, will be sufficient to settle the remaining claims.

Lease agreements. The Company leases offshore production facilities, equipment and office facilities under noncancellable operating leases on which rental expense for the years ended December 31, 2002, 2001 and2000 was approximately $6.7 million, $6.6 million and $7.0 million, respectively. Future minimum lease commitments under noncancellable operating leases at December 31, 2002 are as follows (in thousands):

2003	$ 19,364
2004	$ 41,553
2005	$ 39,375
2006	$ 32,266
2007	$ 26,258
Thereafter	$ 36,338

Transportation agreements. The Company's wholly-owned Canadian subsidiary is a party to pipeline transportation service agreements, with remaining terms of approximately 13 years, whereby it has committed to transport a specified volume of gas each year from Canada to a point in Chicago, Illinois. Such gas volumes are comprised of a significant portion of the Company's Canadian net production, augmented with certain volumes purchased at market prices in Canada. The committed volumes to be transported under the pipeline transportation service agreements are approximately 84 MMcf of gas per day during 2003 and decline to approximately 80 MMcf of gas per day by the end of the commitment term. The net gas marketing gains or losses resulting from purchasing third party gas in Canada and selling it in Chicago are recorded as other income or other expense in the accompanying Consolidated Statements of Operations. Associated with these agreements, the Company recognized $2.6 million and $9.9 million of gas marketing losses in other expenses during 2002 and 2001, respectively.

NOTE J. 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 hedges. The Company monitors capital markets and trends to identify opportunities to enter into interest rate swaps to minimize its costs of capital. As of December 31, 2002, the Company was not a party to any fair value hedges. As of December 31, 2001, the carrying value of the Company's fair value hedges was a liability of $19.6 million.

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 and 8-1/4 percent senior notes, respectively. The terms of the interest rate swap agreements matched the notional amounts and scheduled maturities of the bonds; required the counterparties to pay the Company a fixed annual interest rate equal to the stated bond coupon rates on the notional amounts; and required the Company to pay the counterparties variable annual interest rates on the notional amounts equal to the periodic six-month LIBOR plus weighted average margin rates of 178.2 basis points and 238.1 basis points on the 8-7/8 percent senior notes and 8-1/4 percent senior notes; respectively. During September 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.

During April 2002 the Company entered into interest rate swap agreements to hedge the fair value of the Company's 8-7/8 percent senior notes and, during November 2001, the Company entered into interest rate swap agreements to hedge the fair value of its 6-1/2 percent senior notes and 8-1/4 percent senior notes. The terms of the interest rate swap agreements matched the notional amounts and scheduled maturities of the bonds; required the counterparties to pay the Company fixed annual interest rates equal to the stated bond coupon rates on the notional amounts; and required the Company to pay the counterparties variable annual interest rates on the notional amounts equal to the periodic six-month LIBOR plus weighted average margin rates of 397 basis points, 202.2 basis points, and 337 basis points on the 8-7/8 percent senior notes, 6-1/2 percent senior notes and 8-1/4 percent senior notes; respectively. During September 2002, the Company terminated these interest rate swaps for $36.3 million of cash proceeds, including accrued interest.

As of December 31, 2002, the carrying value of the Company's long-term debt in the accompanying Consolidated Balance Sheets included $35.7 million of incremental liability attributable to the unamortized deferred hedge gains realized from the terminations of the Company's fair value hedge agreements during 2002 and 2001. The amortization of these deferred hedge gains reduced the Company's reported interest expense by $14.1 million and $2.8 million during the years ended December 31, 2002 and 2001, respectively.

The following table sets forth the scheduled amortization of deferred hedge gains on terminated fair value hedges that will be recognized as reductions in the Company's future interest expense:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Outstanding Total
			(in thousands)		
2003 hedge gain amortization	$ 5,937	$ 5,564	$ 4,735	$ 4,161	$ 20,397
2004 hedge gain amortization	$ 3,518	$ 3,122	$ 2,458	$ 2,105	11,203
Remaining net gains to be amortized through 2008					4,072
					$ 35,672

The terms of the fair value hedges described above perfectly matched 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 hedges. The Company utilizes, from time to time, 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 has also utilized 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 reducethe 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 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, 2002:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Yearly Outstanding Total
Daily oil production:					
2003 - Swap Contracts					
Volume (Bbl)	19,900	23,000	23,000	23,000	22,236
Price per Bbl	$ 24.59	$ 24.44	$ 24.40	$ 24.40	$ 24.45
2004 - Swap Contracts					
Volume (Bbl)	14,000	14,000	14,000	14,000	14,000
Price per Bbl	$ 23.11	$ 23.11	$ 23.11	$ 23.11	$ 23.11

The Company reports average oil prices per Bbl including the effects of oil quality adjustments and the net effect of 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,		
	2002	2001	2000
Average price reported per Bbl	$ 22.89	$ 24.12	$ 24.01
Average price realized per Bbl	$ 22.95	$ 23.88	$ 28.81
Addition (reduction) to revenue (in millions)	$ (.8)	$ 3.0	$ (60.1)

Natural gas liquids prices. During the years ended December 31, 2002, 2001 and 2000, 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, 2002:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Yearly Outstanding Average
Daily gas production:					
2003 - Swap Contracts					
Volume (Mcf)	230,000	230,000	230,000	230,000	230,000
Index price per MMBtu	$ 3.76	$ 3.76	$ 3.76	$ 3.76	$ 3.76
2004 - Swap Contracts					
Volume (Mcf)	180,000	180,000	180,000	180,000	180,000
Index price per MMBtu	$ 3.81	$ 3.81	$ 3.81	$ 3.81	$ 3.81
2005 - Swap Contracts					
Volume (Mcf)	10,000	10,000	10,000	10,000	10,000
Index price per MMBtu	$ 3.70	$ 3.70	$ 3.70	$ 3.70	$ 3.70
2006 - Swap Contracts					
Volume (Mcf)	20,000	20,000	20,000	20,000	20,000
Index price per MMBtu	$ 3.75	$ 3.75	$ 3.75	$ 3.75	$ 3.75
2007 - Swap Contracts					
Volume (Mcf)	20,000	20,000	20,000	20,000	20,000
Index price per MMBtu	$ 3.75	$ 3.75	$ 3.75	$ 3.75	$ 3.75

The Company reports average gas prices per Mcf including the effects of Btu content, gas processing and shrinkage adjustments and the net effect of gas hedges. The following table sets forth the Company's gasprices, 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,		
	2002	2001	2000
Average price reported per Mcf	$ 2.49	$ 3.23	$ 2.81
Average price realized per Mcf	$ 2.38	$ 3.20	$ 3.03
Addition/(reduction) to revenue (in millions)	$ 13.6	$ 3.0	$ (29.0)

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 provided for an aggregate notional amount of $55 million of debt; commenced on May 21, 2001 and matured on May 20, 2002; required the counterparties to pay the Company a variable rate equalto the periodic six-month LIBOR plus 125 basis points; and, required the Company to pay the counterparties a weighted average annual rate of 5.43 percent on the notional amount. The Company recognized interest expense of $447 thousand and $185 thousand associated with these interest rate swap agreements during the years ended December 31, 2002 and 2001, respectively. The Company recognized no ineffectiveness associated with changes in the fair values of these derivative instruments.

Foreign currency rates. During 2001, the Company entered into forward agreements to exchange an aggregate $24.8 million U.S. dollars for Canadian dollars at a weighted average exchange rate of .6266 U.S. dollars for 1.0 Canadian dollar. These agreements were designated as hedges of the Company's exchange rate risk associated with Canadian sales of gas under U.S. dollar denominated sales agreements. The Company recognized settlement gains of $249 thousand associated with these forward agreements during the year ended December 31, 2002, which increased the Company's reported gas price. The Company did not recognize any ineffectiveness associated with changes in the fair values of these derivative instruments. Except for one forward agreement that represented an asset of $15 thousand to the Company on December 31, 2002, these agreements matured during the year ended December 31, 2002.

Hedge ineffectiveness and excluded items. During the years ended December 31, 2002 and 2001, the Company recognized other expense of $1.7 million and $9.1 million, respectively, 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 ofhedge 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 three month period ended March 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 records the effective portions of deferred cash flow hedge gains and losses in AOCI - deferred hedge gains, net. Once the underlying hedged transaction occurs the deferred hedge gain or loss is reclassified from AOCI - deferred hedge gains, net to earnings. If it is determined that the underlying hedged transaction is not likely to occur, the deferred hedge gain or loss is reclassified from AOCI - deferred hedge gains, net to other income or other expense during the period in which it is determined that the underlying hedged transaction is not likely to occur. As of December 31, 2002 and 2001, AOCI - deferred hedge gains, net represented net deferred gains of $9.6 million and $201.0 million, respectively. The AOCI - deferred hedge gains, net balance as of December 31, 2002 was comprised of $107.8 million of unrealized deferred hedge losses on the effective portions of open commodity cash flowhedges and $117.4 million of net deferred gains on terminated cash flow hedges. The AOCI - deferred hedge gains, net balance as of December 31, 2001 was comprised of $177.7 million of unrealized deferred 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 decrease in AOCI - deferred hedge gains, net during the year ended December 31, 2002 was primarily attributable to increases in future commodity prices relative to the commodity prices stipulated in the hedge agreements and the reclassification of deferred hedge gains to net income as derivatives matured by their terms. The unrealized deferred hedge gains and losses associated with open cash flow hedges remain subject to market price fluctuations until the positions are either settled under the terms of the hedge agreements or terminated prior to settlement. The net deferred gains and losses on terminated cash flow hedges are fixed.

During the twelve month period ending December 31, 2003, the Company expects to reclassify $73.6 million of net deferred losses associated with open cash flow hedges and $72.1 million of net deferred gains on terminated cash flow hedges from AOCI - deferred hedge gains, net to oil and gas revenue.

The following table sets forth the scheduled reclassifications of deferred hedge gains on terminated cash flow hedges that will be recognized in the Company's future oil and gas revenues:

	First Quarter	Second Quarter	Third Quarter (in thousands)	Fourth Quarter	Total Year
2003 deferred hedge gains	$ 18,123	$ 18,043	$ 18,021	$ 17,864	$ 72,051
2004 deferred hedge gains	$ 11,206	$ 11,156	$ 11,226	$ 11,175	44,763
2005 deferred hedge gains	$ 149	$ 153	$ 156	$ 158	616
					$ 117,430

Non-hedge Derivatives

Btu swap agreements. The Company is a party to Btu swap agreements that mature at the end of 2004. The Btu swap agreements do not qualify for hedge accounting treatment. The Company recorded mark-to-marketadjustments to decrease the carrying value of the Btu swap liability by $.7 million during the year ended December 31, 2001 and to increase the carrying value of the Btu swap liability by $14.6 million during the year ended December 31, 2000.

During the year ended December 31, 2001, the Company entered into offsetting Btu swap agreements that 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 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 a mark-to-market adjustment to increase the carrying value of the foreign exchange swap liabilities by $1.9 million during the year ended December 31, 2000.

Other non-hedge commodity derivatives. During the year ended December 31, 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 the year ended December 31, 2000, did not qualify for hedge accounting treatment. The Company recorded mark-to-market adjustments to increase the carrying value of the associated contract liability by $42.0 million during the year ended December 31, 2000.

NOTE K. 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 one or more of the years ended December 31, 2002, 2001 and 2000:

	Percentage of Consolidated Oil, NGL and Gas Revenues		
	2002	2001	2000
Williams Energy Services	7	11	13
Anadarko Petroleum Corporation	7	10	6

At December 31, 2002, the amounts receivable from Williams Energy Services and Anadarko Petroleum Corporation were $13.4 million and $11.7 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, 2002 and 2001, the Company has $7.6 million of derivative assets for which Enron North America Corp was the Company's counterparty. Associated therewith, the Company recognized bad debt expense of $.4 million and $6.0 million during the years ended December 31, 2002 and 2001, respectively, which amounts are included in other expense in the accompanying Consolidated Statements of Operations.

NOTE L. Interest and Other Income

The Company recorded interest and other income of $11.2 million, $21.8 million and $25.8 million during the years ended December 31, 2002, 2001 and 2000. The major categories of the Company's interest and other income are summarized in the following table:

	Year Ended December 31,		
	2002	2001	2000
		(in thousands)	
Kansas ad valorem escrow adjustments (see Note I)	$ 3,500	$ 1,100	$ 1,000
Excise tax income	2,398	4,126	6,915
Production payment income	-	5,552	1,262
Interest income	642	2,128	3,906
Seismic data sales	87	1,841	1,148
Foreign exchange gains	142	223	220
Other income	4,453	6,808	11,324
	$ 11,222	$ 21,778	$ 25,775

NOTE M. Asset Divestitures

During the years ended December 31, 2002, 2001 and 2000, the Companycompleted asset divestitures for net proceeds of $118.9 million, $113.5 million and $102.7 million, respectively. Associated therewith, the Company recorded gains on disposition of assets of $4.4 million, $7.7 million and $34.2 million during the years ended December 31, 2002, 2001 and 2000, respectively.

Hedge derivative divestitures. During the years ended December 31, 2002 and 2001, the Company terminated, prior to their scheduled maturity, hedge derivatives for cash sales proceeds of $91.3 million and $85.4 million, respectively. Net gains from these divestitures were deferred and are being amortized over the original contract lives of the terminated derivatives as reductions to interest expense or increases to oil and gas revenues. See Note J for more information regarding deferred gains on terminated hedge derivatives.

Available for sale securities divestitures. During the year ended December 31, 2000, the Company sold 3,370,982 shares of common stock of a non-affiliated entity for $59.7 million, recording an associated gain on disposition of assets of $34.3 million. During 2001, the Company sold its remaining 613,250 shares of the non-affiliated entity for $12.7 million of cash proceeds and recognized an associated gain on disposition of assets of $8.1 million.

Other United States divestitures. During the year ended December 31, 2002, the Company received $20.9 million of proceeds from the cash settlement of a gas balancing receivable, $4.7 million from the sale of certain gas properties located in Oklahoma and $1.8 million from the sale of other corporate assets. Associated with these divestitures, the Company recorded net gains of $4.2 million.

During the year ended December 31, 2001, the Company sold other corporate assets for $3.0 million of proceeds. Associated with the sale of these assets, the Company recorded a net gain of $.4 million.

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.

Other international divestitures. During the year ended December 31, 2002, other Canadian and Argentine corporate assets were sold for $.2 million. The Company recorded $.2 million of net gains associated with those divestitures. During the year ended December 31, 2001, the Company 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.

NOTE N. Other Expense

The following table provides the components of the Company's other expense during the years ended December 31, 2002, 2001 and 2000:

	Years Ended December 31,		
	2002	2001	2000
		(in thousands)	
Derivative ineffectiveness and mark-to-market provisions (see Note J)	$ 1,664	$ 11,458	$ 58,518
Gas marketing losses (see Note I)	2,556	9,850	-
Foreign currency remeasurement and exchange losses (a)	7,623	8,474	80
Bad debt expense (see Note K)	129	6,152	65
Other charges	5,284	3,654	8,568
	$ 17,256	$ 39,588	$ 67,231

(a) 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 has remeasured its Argentine peso-denominated monetary net assets as of December 31, 2002 and 2001 and adjusted its lease and well equipment inventory balances to market values as of December 31, 2001. Associated therewith, the Company recognized charges of $6.9 million and $7.7 million during 2002 and 2001, respectively.

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 $2.3 million, $11.7 million and $4.6 million were made during the years ended December 31, 2002, 2001 and 2000, respectively. During the years ended December 31, 2002, 2001 and 2000, the Company's income tax provision (benefit) and amounts separately allocated were attributable to the following items:

	Year Ended December 31,		
	2002	2001	2000
		(in thousands)	
Income (loss) before extraordinary items	$ 5,063	$ 4,016	$ (6,000)
Changes in other comprehensive income:			
Deferred hedge gains and losses	(2,561)	2,293	-
Cumulative translation adjustment	(20)	(121)	(200)
	$ 2,482	$ 6,188	$ (6,200)

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

	Year Ended December 31, 2002	2001	2000
	(in thousands)		
Current:			
U.S. state and local	$ 209	$ 1,080	$ -
Foreign	2,066	10,585	4,600
	2,275	11,665	4,600
Deferred:			
Foreign	2,788	(7,649)	(10,600)
Total	$ 5,063	$ 4,016	$ (6,000)

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

	Year Ended December 31, 2002	2001	2000
	(in thousands)		
Income (loss) before income taxes and extraordinary items:			
U.S. federal	$ 58,821	$ 140,045	$ 138,941
Foreign	(4,699)	(32,280)	19,558
	$ 54,122	$ 107,765	$ 158,499

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

	2002	2001	2000
U.S. federal statutory tax rate	35.0	35.0	35.0
Valuation allowance	(23.7)	(27.5)	(30.9)
Rate differential on foreign operations	(.1)	(3.2)	(2.9)
Other	(1.8)	(.6)	(5.0)
Consolidated effective tax rate	9.4	3.7	(3.8)

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

	December 31, 2002	2001
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 299,495	$ 341,206
Alternative minimum tax credit carryforwards	1,565	1,565
Other	143,894	44,745
Total deferred tax assets	444,954	387,516
Valuation allowance	(277,217)	(183,122)
Net deferred tax assets	167,737	204,394
Deferred tax liabilities:		
Oil and gas properties, principally due to differences in basis, depletion and the deduction of intangible drilling costs for tax purposes	80,364	115,524
Other	5,393	11,919
Total deferred tax liabilities	85,757	127,443
Net deferred tax asset	$ 81,980	$ 76,951

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 a valuation allowance of $277.2 million against the carryforwards at December 31, 2002. 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, 2002, the Company had NOLs for United States, Canadian, South African, Gabonese and Tunisian income tax purposes of $742.7 million, $37.4 million, $40.3 million, $13.4 million and $8.7 million, respectively, which are available to offset future regular taxable income in each respective tax jurisdiction, if any. Additionally, at December 31, 2002, the Company has alternative minimum tax net operating loss carryforwards ("AMT NOLs") in the United States of $637.5 million, which are available to reduce future alternative minimum taxable income, if any. These carryforwards expire as follows:

	U.S.		Canada	South Africa	Gabon	Tunisia
Expiration Date	NOL	AMT NOL	NOL	NOL	NOL	NOL
			(in thousands)			
December 31, 2005 ...	$ -	$ -	$ 31,637	$ -	$ -	$ -
December 31, 2006 ...	-	-	5,738	-	-	-
December 31, 2007 ...	13,320	-	-	-	-	-
December 31, 2008 ...	112,508	104,574	-	-	-	-
December 31, 2009 ...	129,226	102,727	-	-	-	-
December 31, 2010 ...	124,859	110,961	-	-	-	-
December 31, 2011 ...	6,521	4,045	-	-	-	-
December 31, 2012 ...	68,334	58,723	-	-	-	-
December 31, 2018 ...	127,656	98,290	-	-	-	-
December 31, 2019 ...	145,999	144,837	-	-	-	-
December 31, 2020 ...	14,235	13,297	-	-	-	-
Indefinite	-	-	-	40,304	13,397	8,712
Total	$ 742,658	$ 637,454	$ 37,375	$ 40,304	$ 13,397	$ 8,712

The Company believes $160.0 million of the U.S. 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, 2002:						
Oil and gas revenues	$ 573,289	$ 77,615	$ 50,876	$ -	$ -	$ 701,780
Interest and other	-	-	-	-	11,222	11,222
Gain (loss) on disposition of assets	3,248	(3)	995	-	192	4,432
	576,537	77,612	51,871	-	11,414	717,434
Production costs	174,929	13,870	10,771	-	-	199,570
Depletion, depreciation and amortization	140,107	39,659	27,857	-	8,752	216,375
Exploration and abandonments	62,955	10,306	5,841	6,792	-	85,894
General and administrative	-	-	-	-	48,402	48,402
Interest	-	-	-	-	95,815	95,815
Other	-	-	-	-	17,256	17,256
	377,991	63,835	44,469	6,792	170,225	663,312
Income (loss) before income taxes and extraordinary items	198,546	13,777	7,402	(6,792)	(158,811)	54,122
Income tax benefit (provision)	(69,491)	(4,822)	(3,118)	2,377	69,991	(5,063)
Income (loss) before extraordinary items	$ 129,055	$ 8,955	$ 4,284	$ (4,415)	$ (88,820)	$ 49,059
Cost incurred for long-lived assets	$ 533,560	$ 35,121	$ 33,506	$ 70,268	$ -	$ 672,455
Segment assets (as of December 31)	$ 2,375,505	$ 680,063	$ 176,110	$ 118,070	$ 105,368	$ 3,455,116
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

NOTE Q. Income Per Share Before Extraordinary Items

Basic income per share before extraordinary items is computed by dividing income before extraordinary items by the weighted average number of common shares outstanding for the period. The computation of diluted income 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 Company.

The following table is a reconciliation of the basic and diluted weighted average common shares outstanding for the years ended December 31, 2002, 2001 and 2000:

	Year Ended December 31,		
	2002	2001	2000
		(in thousands)	
Weighted average common shares outstanding:			
Basic	112,542	98,529	99,378
Dilutive common stock options (a)	1,725	1,185	385
Restricted stock awards (b)	21	-	-
Diluted	114,288	99,714	99,763

(a) Common stock options to purchase 1,925,743 shares, 3,595,880 shares and 4,911,749 shares of common stock were outstanding but not included in the computations of diluted net income per share for 2002, 2001 and 2000, 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.

(b) During the year ended December 31, 2002, the Company issued 654,445 restricted shares of the Company's common stock. The restricted shares were issued as compensation to directors, officers and key employees of the Company. The restricted shares include 18,545 shares that were granted to directors of the Company on May 13, 2002. Director awards for 3,302 shares vest on a quarterly pro-rata basis during the year ended May 13, 2003, and director awards for 15,243 shares vest on May 13, 2005. The remaining 635,900 restricted shares were awarded to officers and key employees of the Company on August 12, 2002 and vest on August 12, 2005.

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 E 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, 2002 and 2001, and Consolidating Statements of Operations and Comprehensive Income (Loss) and Consolidating Condensed Statements of Cash Flows for the years ended December 31, 2002, 2001 and 2000 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 necessaryto 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, 2002, 2001 and 2000

CONSOLIDATING CONDENSED BALANCE SHEET
As of December 31, 2002

	Pioneer Natural Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries	Eliminations	The Company
			(in thousands)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ 6	$ 1,783	$ 6,701	$	$ 8,490
Other current assets	1,727,828	(1,480,657)	(108,568)		138,603
Total current assets	1,727,834	(1,478,874)	(101,867)		147,093
Property, plant and equipment, at cost:					
Oil and gas properties, using the successful efforts method of accounting:					
Proved properties	-	3,024,845	1,228,052		4,252,897
Unproved properties	-	43,969	175,104		219,073
Accumulated depletion, depreciation and amortization	-	(947,091)	(356,450)		(1,303,541)
	-	2,121,723	1,046,706		3,168,429
Deferred income taxes	75,311	-	1,529		76,840
Other property and equipment, net	-	19,000	3,784		22,784
Other assets, net	16,067	14,231	9,672		39,970
Investment in subsidiaries	1,247,042	136,159	-	(1,383,201)	-
	$ 3,066,254	$ 812,239	$ 959,824		$ 3,455,116
LIABILITIES AND STOCKHOLDERS' EQUITY					
Total current liabilities	$ 30,785	$ 216,065	$ 27,742	$	$ 274,592
Long-term debt, less current maturities	1,668,536	-	-		1,668,536
Other noncurrent liabilities	-	147,970	(19,639)		128,331
Deferred income taxes	-	-	8,760		8,760
Stockholders' equity	1,366,933	448,204	942,961	(1,383,201)	1,374,897
Commitments and contingencies	-	-	-		-
	$ 3,066,254	$ 812,239	$ 959,824		$ 3,455,116

CONSOLIDATING CONDENSED BALANCE SHEET
As of December 31, 2001

	Pioneer Natural Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries	Eliminations	The Company
			(in thousands)		
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

PIONEER NATURAL RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2002, 2001 and 2000

CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS AND COMPREHENSIVE LOSS
For the Year Ended December 31, 2002
(in thousands)

	Pioneer Natural Resources Company (Parent)	Pioneer USA	Non-Guarantor Subsidiaries	Consolidated Income Tax Provision	Eliminations	The Company
Revenues and other income:						
Oil and gas	$ -	$ 527,189	$ 174,591	$ -	$	$ 701,780
Interest and other	-	8,214	3,008	-		11,222
Gain on disposition of assets, net	-	3,230	1,202	-		4,432
	-	538,633	178,801	-		717,434
Costs and expenses:						
Oil and gas production	-	165,669	33,901	-		199,570
Depletion, depreciation and amortization	-	139,822	76,553	-		216,375
Exploration and abandonments	-	62,982	22,912	-		85,894
General and administrative	1,323	37,723	9,356	-		48,402
Interest	17,451	76,820	1,544	-		95,815
Equity (income) loss from subsidiary	(52,580)	8,374	-	-	44,206	-
Other	405	4,879	11,972	-		17,256
	(33,401)	496,269	156,238	-		663,312
Income before income taxes	33,401	42,364	22,563	-		54,122
Income tax provision	-	-	(5,063)	-		(5,063)
Income before extraordinary items	33,401	42,364	17,500	-		49,059
Extraordinary items - loss on early extinguishment of debt	(6,688)	-	(15,658)	-		(22,346)
Net income	26,713	42,364	1,842	-		26,713
Other comprehensive income (loss):						
Deferred hedge gains, net:						
Deferred hedge losses	(4)	(156,396)	(22,667)	-		(179,067)
Net (gains) losses included in net income	447	(10,352)	(2,519)	-		(12,424)
Translation adjustment	-	-	2,188	-		2,188
Comprehensive income (loss)	$ 27,156	$ (124,384)	$ (21,156)	$ -		$ (162,590)

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 and other income:						
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, net:						
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

PIONEER NATURAL RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2002, 2001 and 2000

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 and other income:						
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

CONSOLIDATING CONDENSED STATEMENT OF CASH FLOWS
For the Year Ended December 31, 2002
(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	$ (327,185)	$ 406,939	$ 252,491	$ 332,245
Cash flows from investing activities:				
Proceeds from disposition of assets	31,994	86,703	153	118,850
Additions to oil and gas properties	-	(365,981)	(248,717)	(614,698)
Other property (additions) retirements, net	-	(13,171)	888	(12,283)
Net cash provided by (used in) investing activities	31,994	(292,449)	(247,676)	(508,131)
Cash flows from financing activities:				
Borrowings under long-term debt	529,805	-	-	529,805
Principal payments on long-term debt	(481,783)	-	-	(481,783)
Issuance of common stock	236,000	-	-	236,000
Payments of noncurrent liabilities	-	(123,607)	(638)	(124,245)
Deferred loan fees/issuance costs	(3,293)	-	-	(3,293)
Exercise of stock options and employee stock purchases	14,389	-	-	14,389
Net cash provided by (used in) financing activities	295,118	(123,607)	(638)	170,873
Net increase (decrease) in cash and cash equivalents	(73)	(9,117)	4,177	(5,013)
Effect of exchange rate changes on cash and cash equivalents	-	-	(831)	(831)
Cash and cash equivalents, beginning of period	79	10,900	3,355	14,334
Cash and cash equivalents, end of period	$ 6	$ 1,783	$ 6,701	$ 8,490

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

PIONEER NATURAL RESOURCES COMPANY

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

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

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2002, 2001 and 2000

Capitalized Costs

	December 31, 2002	December 31, 2001
	(in thousands)	
Oil and Gas Properties:		
Proved	$ 4,252,897	$ 3,691,783
Unproved	219,073	187,785
	4,471,970	3,879,568
Less accumulated depletion	(1,303,541)	(1,095,310)
Net capitalized costs for oil and gas properties	$ 3,168,429	$ 2,784,258

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, 2002:					
United States	$ 156,736	$ 34,048	$ 72,831	$ 269,945	$ 533,560
Argentina	12	51	14,530	20,528	35,121
Canada	457	2,329	9,992	20,728	33,506
South Africa	-	-	2,789	34,300	37,089
Gabon	-	-	23,585	-	23,585
Tunisia	-	1,843	6,320	-	8,163
Other foreign	-	-	1,431	-	1,431
Total costs incurred	$ 157,205	$ 38,271	$ 131,478	$ 345,501	$ 672,455
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
Gabon	-	-	11,387	-	11,387
Tunisia	-	1,835	3,652	-	5,487
Other foreign	-	-	4,471	-	4,471
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
Gabon	-	-	1,326	-	1,326
Other foreign	-	-	2,095	-	2,095
Total costs incurred	$ 35,980	$ 31,225	$ 130,770	$ 141,765	$ 339,740

Results of Operations

Information about the Company's results of operations for oil andgas 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 as of December 31, 2002, which are located principally in the United States, Argentina, Canada, South Africa and Tunisia, were based on evaluations audited by independent petroleum engineers with respect to the Company's major properties and prepared by the Company's engineers with respect to all other properties. The estimates of the Company's proved oil and gas reserves as of December 31, 2001 and 2000 were 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 2002, 2001 and 2000 utilize respective oil prices of $29.67, $18.88 and $25.71 per Bbl (reflecting adjustments for oil quality); respective NGL prices of $19.01, $11.58 and $16.74 per Bbl; and, respective gas prices of $3.37, $2.21 and $7.50 per Mcf (reflecting adjustments for Btu content, 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.

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2002, 2001 and 2000

Oil and Gas Producing Activities:

	2002			2001			2000		
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	279,146	1,474,090	524,829	266,802	1,354,327	492,523	259,066	1,314,842	478,206
Revisions of previous estimates	61,529	5,983	62,525	(1,179)	41,039	5,661	19,295	63,912	29,947
Purchases of minerals-in-place	8,634	83,361	22,528	24,943	63,113	35,462	1,237	28,071	5,916
New discoveries and extensions	4,364	5,349	5,255	4,442	93,220	19,979	4,819	66,486	15,900
Production	(16,042)	(84,812)	(30,177)	(15,862)	(77,609)	(28,796)	(16,872)	(83,930)	(30,860)
Sales of minerals-in-place	-	-	-	-	-	-	(743)	(35,054)	(6,586)
Balance, December 31	337,631	1,483,971	584,960	279,146	1,474,090	524,829	266,802	1,354,327	492,523
ARGENTINA									
Balance, January 1	35,669	471,150	114,193	35,843	408,282	103,890	29,797	415,620	99,067
Revisions of previous estimates	(4,954)	47,829	3,017	(932)	4,460	(189)	1,411	(15,558)	(1,182)
Purchases of minerals-in-place	-	-	-	170	31,700	5,453	-	-	-
New discoveries and extensions	3,985	41,652	10,927	4,354	58,538	14,110	8,066	43,914	15,385
Production	(3,168)	(28,550)	(7,926)	(3,766)	(31,830)	(9,071)	(3,431)	(35,694)	(9,380)
Balance, December 31	31,532	532,081	120,211	35,669	471,150	114,193	35,843	408,282	103,890
CANADA									
Balance, January 1	2,659	132,061	24,669	4,066	132,919	26,219	3,970	145,251	28,179
Revisions of previous estimates	24	(1,150)	(167)	212	15,067	2,723	429	(10,013)	(1,240)
Purchases of minerals-in-place	-	-	-	-	-	-	140	7,768	1,435
New discoveries and extensions	68	6,070	1,080	81	5,644	1,022	138	6,132	1,160
Production	(390)	(17,653)	(3,333)	(671)	(18,426)	(3,742)	(611)	(16,219)	(3,315)
Sales of minerals-in-place	-	-	-	(1,029)	(3,143)	(1,553)	-	-	-
Balance, December 31	2,361	119,328	22,249	2,659	132,061	24,669	4,066	132,919	26,219
SOUTH AFRICA									
Balance, January 1	7,685	-	7,685	5,552	-	5,552	-	-	-
Revisions of previous estimates	790	-	790	-	-	-	-	-	-
Purchases of minerals-in-place	-	-	-	2,133	-	2,133	-	-	-
New discoveries and extensions	-	-	-	-	-	-	5,552	-	5,552
Balance, December 31	8,475	-	8,475	7,685	-	7,685	5,552	-	5,552
TUNISIA									
Balance, January 1	-	-	-	-	-	-	-	-	-
New discoveries and extensions	845	-	845	-	-	-	-	-	-
Balance, December 31	845	-	845	-	-	-	-	-	-
TOTAL									
Balance, January 1	325,159	2,077,301	671,376	312,263	1,895,528	628,184	292,833	1,875,713	605,452
Revisions of previous estimates (a)	57,389	52,662	66,165	(1,899)	60,566	8,195	21,135	38,341	27,525
Purchases of minerals-in-place	8,634	83,361	22,528	27,246	94,813	43,048	1,377	35,839	7,351
New discoveries and extensions	9,262	53,071	18,107	8,877	157,402	35,111	18,575	116,532	37,997
Production	(19,600)	(131,015)	(41,436)	(20,299)	(127,865)	(41,609)	(20,914)	(135,843)	(43,555)
Sales of minerals-in-place	-	-	-	(1,029)	(3,143)	(1,553)	(743)	(35,054)	(6,586)
Balance, December 31	380,844	2,135,380	736,740	325,159	2,077,301	671,376	312,263	1,895,528	628,184
Proved Developed Reserves:									
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
January 1	227,227	1,464,324	471,281	232,531	1,507,826	483,836	235,165	1,538,310	491,551
United States	209,948	1,067,701	387,899	196,893	1,027,750	368,184	206,922	1,081,592	387,188
Argentina	22,180	402,640	89,287	28,248	341,967	85,243	22,679	345,281	80,226
Canada	2,042	90,003	17,042	2,086	94,607	17,854	2,930	80,953	16,422
December 31	234,170	1,560,344	494,228	227,227	1,464,324	471,281	232,531	1,507,826	483,836

(a) The revisions of previous estimates above, include revisions attributable to changes in commodity prices totaling a 28,643 MBOE increase, a 24,970 MBOE decrease and a 14,009 MBOE increase for the years ended December 31, 2002, 2001 and 2000, respectively.

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, 2002 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 a liability equal to approximately $226 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.

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2002, 2001 and 2000

	For the Year Ended December 31,		
	2002	2001	2000
		(in thousands)	
UNITED STATES			
Oil and gas producing activities:			
Future cash inflows	$ 15,161,717	$ 8,222,573	$ 18,660,169
Future production costs	(4,830,294)	(3,231,730)	(4,907,134)
Future development costs	(864,386)	(735,984)	(479,290)
Future income tax expense	(2,325,946)	(598,612)	(3,777,157)
	7,141,091	3,656,247	9,496,588
10% annual discount factor	(3,684,400)	(1,691,118)	(4,780,133)
Standardized measure of discounted future cash flows	$ 3,456,691	$ 1,965,129	$ 4,716,455
ARGENTINA			
Oil and gas producing activities:			
Future cash inflows	$ 986,716	$ 1,070,664	$ 1,183,652
Future production costs	(175,938)	(227,435)	(215,853)
Future development costs	(84,669)	(144,604)	(114,606)
Future income tax expense	(143,845)	(45,140)	(81,705)
	582,264	653,485	771,488
10% annual discount factor	(242,158)	(262,334)	(264,126)
Standardized measure of discounted future cash flows	$ 340,106	$ 391,151	$ 507,362
CANADA			
Oil and gas producing activities:			
Future cash inflows	$ 502,260	$ 301,002	$ 1,029,007
Future production costs	(89,246)	(73,601)	(104,189)
Future development costs	(22,294)	(27,050)	(35,443)
Future income tax expense	(87,363)	(10,771)	(306,399)
	303,357	189,580	582,976
10% annual discount factor	(104,345)	(59,995)	(168,441)
Standardized measure of discounted future cash flows	$ 199,012	$ 129,585	$ 414,535
SOUTH AFRICA			
Oil and gas producing activities:			
Future cash inflows	$ 256,436	$ 149,777	$ 126,134
Future production costs	(92,820)	(73,697)	(65,232)
Future development costs	(23,200)	(54,281)	(47,970)
Future income tax expense	(4,465)	-	-
	135,951	21,799	12,932
10% annual discount factor	(14,588)	(7,338)	(5,782)
Standardized measure of discounted future cash flows	$ 121,363	$ 14,461	$ 7,150
TUNISIA			
Oil and gas producing activities:			
Future cash inflows	$ 23,460	$ -	$ -
Future production costs	(2,396)	-	-
Future development costs	(3,570)	-	-
Future income tax expense	(6,447)	-	-
	11,047	-	-
10% annual discount factor	(1,667)	-	-
Standardized measure of discounted future cash flows	$ 9,380	$ -	$ -
TOTAL			
Oil and gas producing activities:			
Future cash inflows	$ 16,930,589	$ 9,744,016	$ 20,998,962
Future production costs	(5,190,694)	(3,606,463)	(5,292,408)
Future development costs	(998,119)	(961,919)	(677,309)
Future income tax expense	(2,568,066)	(654,523)	(4,165,261)
	8,173,710	4,521,111	10,863,984
10% annual discount factor	(4,047,158)	(2,020,785)	(5,218,482)
Standardized measure of discounted future cash flows	$ 4,126,552	$ 2,500,326	$ 5,645,502

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2002, 2001 and 2000

Oil and Gas Producing Activities

	For the Year Ended December 31, 2002	2001 (in thousands)	2000
Oil and gas sales, net of production costs	$ (489,338)	$ (631,365)	$ (663,473)
Net changes in prices and production costs	2,042,575	(4,528,168)	3,829,794
Extensions and discoveries	152,253	184,454	525,361
Development costs incurred during the period	262,469	239,156	101,350
Sales of minerals-in-place	-	(23,372)	(72,624)
Purchases of minerals-in-place	187,460	201,535	187,097
Revisions of estimated future development costs	(387,404)	(429,365)	(200,734)
Revisions of previous quantity estimates	527,987	40,771	344,454
Accretion of discount	250,033	701,943	293,726
Changes in production rates, timing and other	99,722	(274,689)	(262,784)
Change in present value of future net revenues	2,645,757	(4,519,100)	4,082,167
Net change in present value of future income taxes	(1,019,531)	1,373,924	(1,373,924)
	1,626,226	(3,145,176)	2,708,243
Balance, beginning of year	2,500,326	5,645,502	2,937,259
Balance, end of year	$ 4,126,552	$ 2,500,326	$ 5,645,502

Selected Quarterly Financial Results

	Quarter First	Second (in thousands, except per share data)	Third	Fourth
2002				
Operating revenues	$ 165,539	$ 172,430	$ 168,317	$ 195,494
Total revenues and other income	$ 166,658	$ 174,338	$ 178,753	$ 197,685
Costs and expenses	$ 169,027	$ 158,916	$ 157,953	$ 177,416
Net income (loss):				
Before extraordinary items	$ (1,959)	$ 13,985	$ 18,611	$ 18,422
Extraordinary items, net of tax (a)	-	(2,843)	(19,501)	(2)
Net income (loss)	$ (1,959)	$ 11,142	$ (890)	$ 18,420
Net income (loss) per share:				
Basic:				
Before extraordinary items	$ (.02)	$ .13	$ .16	$ .16
Extraordinary items	-	(.03)	(.17)	-
Net income (loss)	$ (.02)	$ .10	$ (.01)	$ .16
Diluted:				
Before extraordinary items	$ (.02)	$ .12	$ .16	$ .16
Extraordinary items	-	(.02)	(.17)	-
Net income (loss)	$ (.02)	$ .10	$ (.01)	$ .16
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)

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 15, 2003 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 15, 2003 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 15, 2003 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 15, 2003 and is incorporated herein by reference.

ITEM 14. CONTROLS AND PROCEDURES

(a) ***Evaluation of disclosure controls and procedures.*** Within 90 days prior to the filing date of this Report, the Company's principal executive officer ("CEO") and principal financial officer ("CFO") carried out an evaluation of the effectiveness of the Company's disclosure controls and procedures. Based on those evaluations, the Company's CEO and CFO believe (i) that the Company's disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in the reports it files under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and that such information is accumulated and communicated to the Company's management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure; and (ii) that the Company's disclosure controls and procedures are effective.

(b) ***Changes in internal controls.*** There have been no significant changes in the Company's internal controls or in other factors that could significantly affect the Company's internal controls subsequent to the evaluation referred to in Item 14. (a), above, nor have there been any corrective actions with regard to significant deficiencies or material weaknesses.

PART IV

ITEM 15. 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, 2002 and 2001
Consolidated Statements of Operations for the years ended December 31, 2002, 2001 and 2000
Consolidated Statements of Stockholders' Equity for the years ended December 31, 2002, 2001 and 2000
Consolidated Statements of Cash Flows for the years ended December 31, 2002, 2001 and 2000
Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2002, 2001 and 2000
Notes to Consolidated Financial Statements
Unaudited Supplementary Information

(b) Reports on Form 8-K

During the three months ended December 31, 2002, the Company filed one Current Report on Form 8-K dated October 24, 2002. The Company's October 24, 2002 Form 8-K provided, under Items 7 and 9, (i) the Company's news release dated October 24, 2002 that announced the Company's financial and operating results for the three and nine month periods ended September 30, 2002, an operational update and the Company's fourth quarter 2002 financial outlook; and (ii) tables summarizing, as of October 23, 2002, the Company's open oil hedge positions, open gas hedge positions and deferred hedge gains and losses on terminated commodity hedges.

(c) Exhibits

The exhibits to this Report required to be filed pursuant to Item 15(c) are listed below and in the "Index to Exhibits" attached hereto.

(d) Financial Statement Schedules

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

SHAREHOLDER INFORMATION

SHAREHOLDER INFORMATION

Stock Exchange Listing
Ticker symbol: PXD
New York 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

Annual Meeting
The Annual Meeting of stockholders will be held Thursday, May 15, 2003 at 9:00 a.m. at the Marriott Las Colinas Hotel, 223 West Las Colinas Blvd., Irving, Texas.

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
Stockholders, 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.

SUBSIDIARIES

Pioneer Natural Resources Canada Inc.
Kenneth H. Sheffield, Jr.,
President
2900, 255-5th Avenue S.W.
Calgary, AB T2P 3G6
Canada
Telephone: (403) 231-3100

Pioneer Natural Resources (Argentina) S.A.
Güimar J. Vaca Coca,
President
Della Paolera 265, 24th Floor
C1001ADA-Buenos Aires, Argentina
Telephone: 5411 4312-9081

Pioneer Natural Resources South Africa (PTY) Limited
Marek Ranoszek,
General Manager
1 Thibault Square – Long Street,
21st Floor
Cape Town 8001, RSA
Telephone: 2721 425-5012

Pioneer Resources Gabon – Olowi Ltd.
Francklin Assoko-Mve,
Resident Representative
Hotel Intercontinental
Okoume Palace R. #315
BP 641
Libreville, Gabon, West Africa
Telephone: 241 73-4646

Pioneer Natural Resources Tunisia LTD
Hashim Alkhersan,
Manager
La Residence Lakeo, 3rd Floor - 6C
Rue Du Lac Michigan
1053 Tunis, Tunisia
Telephone: 216 7196 0885

BOARD OF DIRECTORS:

Scott D. Sheffield
Chairman, President
and Chief Executive Officer

James R. Baroffio [3,4]
Former President
Chevron Canada Resources

Edison C. Buchanan [3,4]
Former Managing Director
Credit Suisse First Boston

R. Hartwell Gardner [2,4]
Retired Treasurer
Mobil Corporation

James L. Houghton [2,4]
Retired Senior Tax Partner
Ernst & Young, L.L.P.

Jerry P. Jones [2,4]
Retired Shareholder and Of Counsel
Thompson & Knight, P.C.

Linda K. Lawson [2,4]
Former Vice President
Williams Companies

Charles E. Ramsey, Jr. [1,3,4]
Financial Consultant

Robert A. Solberg [2,4]
Retired Vice President
Texaco, Inc.

[1] Lead Director
[2] Audit Committee
[3] Compensation Committee
[4] Nominating and Corporate Governance Committee

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

Sharron Y. DeLancey
Assistant Corporate Secretary

Thomas C. Halbouty
Vice President
and Chief Information Officer

Larry N. Paulsen
Vice President,
Administration and Risk Management

Susan A. Spratlen
Vice President,
Investor Relations and Communication

PIONEER NATURAL RESOURCES
1400 Williams Square West
5205 N. O'Connor Blvd.
Irving, TX 75039
972.444.9001
www.pioneernrc.com

The mustang sculpture featured on the cover is located in the plaza near Pioneer's Las Colinas headquarters in Williams Square.