POGO PRODUCING CO
Form 10-K
February 24, 2004

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2003

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

for the transition period from to
Commission File No. 1-7792

Pogo Producing Company

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**74-1659398** (I.R.S. Employer Identification No.)
5 Greenway Plaza, P.O. Box 2504 **Houston, Texas** (Address of principal executive offices)	**77252-2504** (Zip Code)

Registrant's telephone number, including area code: **(713) 297-5000**

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

Title of each class:	Name of each exchange on which registered:
Common Stock, $1 par value	**New York Stock Exchange** **Pacific Exchange**
Preferred Stock Purchase Rights	**New York Stock Exchange**

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

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

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. ý

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ý No o

The aggregate market value of the Common Stock held by non-affiliates of the registrant (treating all executive officers and directors of the registrant, for this purpose, as if they may be affiliates of the registrant) was approximately $2,648,832,750 as of June 30, 2003 (based on $42.75 per share, the last sale price of the Common Stock as reported on the New York Stock Exchange Composite Tape on such date).

63,812,824 shares of the registrant's Common Stock were outstanding as of February 13, 2004.

DOCUMENT INCORPORATED BY REFERENCE

Portions of the Company's definitive Proxy Statement respecting the annual meeting of shareholders to be held on April 27, 2004 (to be filed not later than 120 days after December 31, 2003) are incorporated by reference in Part III of this Form 10-K.

FORWARD LOOKING STATEMENTS

The statements included or incorporated by reference in this Annual Report on Form 10-K for the year ended December 31, 2003 (this "Annual Report") include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements included or incorporated by reference herein, other than statements of historical fact, are forward-looking statements. In some cases, you can identify the Company's forward-looking statements by the words "anticipate," "estimate," "expect," "objective," "projection," "forecast," "goal," and similar expressions. Such forward-looking statements include, without limitation, the statements herein and therein regarding the timing of future events regarding the operations of Pogo Producing Company (the "Company") and its subsidiaries, and the statements under the caption "Management's Discussion and Analysis of Financial Condition and Results of Operations" regarding the Company's anticipated future financial position and cash requirements. Although the Company believes that the expectations reflected in these forward-looking statements are reasonable, it can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from the Company's expectations ("Cautionary Statements") are disclosed in this Annual Report and in other filings by the Company with the Securities and Exchange Commission (the "Commission"). All subsequent written and oral forward-looking statements attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by the Cautionary Statements. The Company's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and other factors set forth in or incorporated by reference in this Annual Report. These factors include:

- the cyclical nature of the oil and natural gas industries
- the Company's ability to successfully and profitably find, produce and market oil and gas
- uncertainties associated with the United States and worldwide economies
- current and potential governmental regulatory actions in countries where the Company operates
- substantial competition from larger companies

- the Company's ability to implement cost reductions
- the Company's ability to acquire additional oil and gas reserves
- operating interruptions (including leaks, explosions, fires, mechanical failure, unscheduled downtime, transportation interruptions, and spills and releases and other environmental risks)
- fluctuations in foreign currency exchange rates in areas of the world where the Company conducts operations, particularly Southeast Asia
- covenant restrictions in the Company's debt agreements

Many of those factors are beyond the Company's ability to control or predict. Management cautions against putting undue reliance on forward-looking statements or projecting any future results based on such statements or present or prior earnings levels.

All subsequent written and oral forward-looking statements attributable to the Company and persons acting on the Company's behalf are qualified in their entirety by the Cautionary Statements contained in this section and elsewhere in this Annual Report.

CERTAIN DEFINITIONS

As used in this Annual Report, "Mcf" means thousand cubic feet, "MMcf" means million cubic feet, "Bcf" means billion cubic feet, "Bbl" means barrel, "MBbls" means thousand barrels and "MMBbls" means million barrels. "BOE" means barrel of oil equivalent, "Mcfe" means thousand cubic feet of natural gas equivalent, "MMcfe" means million cubic feet of natural gas equivalent and "Bcfe" means billion cubic feet of natural gas equivalent. Natural gas equivalents and crude oil equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids ("NGL"). References to "$" and "dollars" refer to United States dollars. All estimates of reserves contained in this Annual Report, unless otherwise noted, are reported on a "net" basis. Information regarding production, acreage and numbers of wells are set forth on a gross basis, unless otherwise noted.

PART I

ITEM 1. *Business.*

The Company was incorporated in 1970 and is engaged in oil and gas exploration, development, acquisition and production activities on its properties located offshore in the Gulf of Mexico, onshore in selected areas including Texas, New Mexico, Wyoming and Louisiana, and internationally, primarily in the Gulf of Thailand and in Hungary. As of December 31, 2003, the Company had interests in 78 lease blocks offshore Louisiana and Texas, approximately 484,000 gross acres onshore in the United States, approximately 734,000 gross acres offshore in the Kingdom of Thailand, approximately 81,000 gross acres in the Danish sector of the North Sea, approximately 764,000 gross acres in Hungary. On February 4, 2004, the Company acquired interests in approximately 1,014,000 gross acres in New Zealand.

The Company organizes its exploration and production activities principally into five operating regions and a New Ventures Group. The operating regions are its Gulf of Mexico region, which is responsible for the Company's operations offshore Texas and Louisiana in the Gulf of Mexico; its Western U.S. region, which is active in the Permian Basin area in New Mexico and West Texas, in the San Juan Basin in New Mexico and in the Madden Field in Wyoming; its Gulf Coast region, which includes the Company's onshore operations principally in South Texas and Louisiana; the Asia and Pacific region, which has responsibility for the Company's operations on its Block B8/32 Concession in the Kingdom of Thailand (the "Thailand Concession") and in New Zealand; and its Europe region, which is currently active principally in Hungary and the North Sea. The Company's New Ventures Group is primarily responsible for identifying new projects and opportunities for the Company outside the United States.

Domestic Offshore Operations

Gulf of Mexico Region. Historically, the Company's interests have been concentrated in the Gulf of Mexico, where approximately 21% of the Company's proved reserves were located as of December 31, 2003. During 2003, approximately 23% of the Company's natural gas production and 53% of its oil and condensate production came from the Company's domestic offshore properties, contributing approximately 42% of the Company's consolidated oil and gas revenues. The Company's exploration and development efforts are primarily focused in the shallower waters of the continental shelf.

Exploration and Development

The scope of exploration and development programs relating to the Company's offshore interests is affected by prices for oil and gas, and by federal, state and local legislation, regulations and ordinances applicable to the petroleum industry. The Company's domestic offshore capital and exploration expenditures for 2003 were approximately $60,500,000, or 54% lower than the Company's domestic offshore capital and exploration expenditures of approximately $130,265,000 for 2002, and 65% lower than the Company's domestic offshore capital and exploration expenditures of approximately $170,800,000 (excluding approximately $87,700,000 of net property acquisitions principally related to the North Central

Oil Corporation acquisition) for 2001. The decrease in the Company's domestic offshore capital and exploration expenditures for 2003, compared with 2002, resulted primarily from decreased expenditures for facilities construction. During 2003, the Company invested approximately $9,495,000 on facilities construction for its Gulf of Mexico operations. The Company has currently budgeted approximately $80,000,000 for capital and exploration expenditures during 2004 in the Gulf of Mexico, of which approximately $17,000,000 is budgeted for facilities construction.

The Company maintains a significant presence in the Gulf of Mexico where it participated in drilling 10 wells during 2003, 80% of which were considered successful. At December 31, 2003, the Company held varying interests in 209 producing oil and gas wells in the Gulf of Mexico.

Leases acquired by the Company and other participants in its bidding groups are customarily committed, on a block-by-block basis, to separate operating agreements under which the appointed operator supervises exploration and development operations for the account and at the expense of the group. These agreements usually contain terms and conditions that have become relatively standardized in the industry. Major decisions regarding development and operations typically require the consent of at least a majority (in working interest) of the participants. Because the Company generally has a meaningful working interest position, the Company believes it can significantly influence (but not always control) decisions regarding development and operations on most of the leases in which it has a working interest even though it may not be the operator of a particular lease. The Company is the operator on all or a portion of 41 of the 78 offshore leases in which it had an interest as of December 31, 2003.

Platforms and related facilities are installed on an offshore lease block when, in the judgment of the lease interest owners, the necessary capital expenditures are justified. A decision to install a platform generally is made after the drilling of one or more exploratory wells with contracted drilling equipment. Platform costs vary depending on, among other factors, the number of well slots, water depth, currents, and sea floor conditions.

Lease Acquisitions

The Company has participated, either on its own or with other companies, in bidding on and acquiring interests in federal and state leases offshore in the Gulf of Mexico since 1970. As a result of such purchases and subsequent activities, as of December 31, 2003, the Company owned interests in 66 federal leases and 12 state leases offshore Louisiana and Texas. Federal leases generally have primary terms of five, eight or ten years, depending on water depth, and state leases generally have terms of three or five years, depending on location, in each case subject to extension by development and production operations.

As part of its strategy, the Company intends to continue an active lease evaluation program in the Gulf of Mexico in order to identify exploration and exploitation opportunities. The Company acquires leases through participation in federal and state lease sales, farmouts and by acquisition. For example, the Company acquired 10 offshore leases at the lease sale conducted by the Minerals Management Service of the Department of the Interior (the "MMS") on March 19, 2003. The Company also acquired one state lease through sales conducted by the State of Louisiana in 2003. The Company also maintains an asset rationalization process through which it seeks to sell or farmout blocks that the Company believes have little or no remaining upside potential, or that face significant future expenditures that would likely result in a rate of return that does not meet the Company's internal criteria. As part of this process, the Company farmed out two leases in 2003. The extent to which the Company participates in future bidding on federal or state offshore lease sales or otherwise acquires additional lease blocks will depend on the availability of funds and its estimates of hydrocarbon deposits, operating expenses and future revenues that may reasonably be expected from available lease blocks. Such estimates typically take into account, among other things, estimates of future hydrocarbon prices, federal regulations and taxation policies applicable to the petroleum industry. It is also the Company's objective to acquire producing leasehold properties in

areas where additional low-risk exploration and development drilling or improved production methods can provide attractive rates of return.

Domestic Onshore Operations

The Company's Gulf Coast region is headquartered in Houston, Texas, with field offices in Laredo and Manvel, Texas. The Company's Western U.S. region has an office in Midland, Texas and two field offices in Southeastern New Mexico. The Company conducts its onshore operations in the United States directly and through its wholly owned subsidiaries, North Central Oil Corporation ("North Central") and Arch Petroleum Inc. Domestic onshore reserves as of December 31, 2003, accounted for approximately 56% of the Company's total proved reserves, with the Gulf Coast region and the Western U.S. region contributing approximately 19% and 37%, respectively, of the Company's total proved reserves. During 2003, approximately 48% of the Company's natural gas production and 14% of its oil and condensate production was from its domestic onshore properties, contributing approximately 31% of the Company's consolidated oil and gas revenues.

Exploration and Development

Western U.S. Region. The Company's Western U.S. region has actively explored West Texas and New Mexico for more than 24 years, and during this period has participated in the discovery or development of over 29 oil and gas fields. In 2003, the Company participated in the drilling of 97 wells (97% of which were successfully completed). The Company believes that during the past decade it has been one of the most active companies drilling for oil and natural gas in southeastern New Mexico (Lea and Eddy Counties), where the Company has interests in approximately 125,000 gross acres. The Company currently plans to drill approximately 106 wells in the Permian Basin during 2004 in various known fields and exploratory prospects. Drilling objectives of these wells range in depth from 1,700 feet to 15,700 feet below the surface and target numerous formations including, among others, the San Andres, Glorieta, San Angelo, Delaware (Brushy Canyon), Clearfork, Bone Springs, Spraberry, Wolfcamp, Canyon, Strawn, Atoka, Morrow and Devonian pay zones.

The Company's Western U.S. region also actively participates in the exploration and development of the Madden Deep Unit in central Wyoming, where the Company currently is credited with varying working interests that average approximately 14% across the unit area. Recent drilling activity in the Madden Deep Unit involves two principal producing horizons, the comparatively shallow Lower Fort Union formation (where productive zones are historically found from approximately 5,500 feet to 9,500 feet below the surface) and the Madison formation (which currently produces from zones located approximately 23,500 feet to 25,000 feet below the surface). The gas produced from the Lower Fort Union formation is comparatively dry sweet gas. Gas produced from the Madison formation, however, contains significant quantities (approximately one-third by volume) of carbon dioxide and hydrogen sulfide gases. Gas from the Madison zones must be processed through the Lost Cabin Gas Plant to remove the carbon dioxide and hydrogen sulfide gases prior to sale. An expansion of the Lost Cabin Gas Plant was completed in 2002, which increased the plant's processing capacity from 132 MMcf per day to approximately 313 MMcf per day. The Company owns a working interest of approximately 15% in this plant. The wells to the Madison formation are deep and technologically challenging to drill, taking up to 12 months from commencement to completion. One Madison test (the Bighorn 9-4) was successfully completed as a producing gas well during 2003. Additionally, a 20,800' Frontier test has recently commenced and is scheduled to be completed in 2004. This exploratory well is located in an area of established production from the Lower Fort Union and Madison formations. If this test is successful, development opportunities may extend over a portion of the Madden structure, with reservoir quality being the primary risk. An active Lower Fort Union drilling program is also anticipated for 2004.

In the second quarter of 2003, Burlington Resources, Inc., operator of the Madden Deep Unit, curtailed production from the Madison formation to evaluate and repair deformations found in the flow

lines transporting production from the wellheads to the Lost Cabin Gas Plant. At the time production was curtailed, Pogo's net share of sellable gas from the Madison formation was approximately 18.9 MMcf per day. Throughout the balance of 2003, production continued to be curtailed at varying rates. Pogo's net share of gas sales from the Madison formation at the beginning of January 1, 2004, was estimated to be approximately

16.7 MMcf per day (which includes volumes attributable to interests acquired through acquisitions).

Gulf Coast Region. The Company's Gulf Coast region is actively exploring for, acquiring and developing oil and gas reserves in the coastal onshore areas of Louisiana and Texas. During 2003, the Gulf Coast region participated in drilling 53 wells, 89% of which were successfully completed.

The Company's Gulf Coast region was most active during 2003 drilling on its 66,000 gross acres of leasehold in South Texas' Webb and Zapata Counties. The Company has been developing gas reserves primarily in its Los Mogotes, Hundido, South Hundido, Hereford Ranch, Mujeres Creek and Mancho Prado Fields that produce from Asche, Charco and Lobo members of the Wilcox formation, found at depths ranging from 7,000 to 14,000 feet below the surface. In its Los Mogotes Field, where its working interest averages 72%, the Company drilled 27 wells in 2003. The Company currently has three contract drilling rigs running in South Texas and those rigs are expected to spend the majority of their time working in the Los Mogotes Field drilling 34 wells budgeted in 2004. A total of four wells were drilled in the Company's 100%-owned South Hundido Fields in 2003 and six more wells have been scheduled for drilling in 2004.

During 2003, the Company participated in drilling three Miocene wells in South Louisiana. One well operated by an industry partner is a new field discovery that is expected to see additional development in 2004. In the Upper Texas Gulf Coast, a new Woodbine formation discovery well has been drilled by the Company and is anticipated to be followed up by drilling several appraisal wells in 2004. The Company undertook several new projects in the Wilcox trend along the Central Texas coastal area and is expanding its presence in this trend. The projects include participation in two wildcat wells operated by an industry partner and the acquisition of a producing property upon which additional Company-operated development drilling has commenced.

The Company's onshore capital and exploration expenditures for 2003 were approximately $142,400,000 (excluding approximately $177,700,000 of net property acquisitions), or 7% higher than comparable expenditures for 2002, and approximately equal to comparable expenditures for 2001. The increase in the Company's onshore capital and exploration expenditures for 2003, compared to 2002, resulted primarily from expenditures related to increased exploratory and development drilling. The Company has currently budgeted approximately $182,000,000 for capital and exploration expenditures during 2004 in its domestic onshore areas.

The Company generally conducts its onshore activities through joint ventures and other interest sharing arrangements with major and independent oil companies. The Company and its subsidiaries operate many of their onshore properties using both independent contractors and field personnel that are employed by the Company or its subsidiaries.

Property Acquisitions

In four transactions in 2003, the Company acquired interests in producing properties located primarily in Andrews, Schleicher and Irion Counties in West Texas, Wharton County in the Texas Gulf Coast area, and the San Juan Basin in New Mexico. In addition, in two additional transactions, the Company increased its working interest in the Madden Field from approximately 12.5% to 14%. The aggregate purchase price for these transactions was approximately $178 million and the aggregate reserves associated with these acquisitions were approximately 155 bcfe.

As it has in recent years, in 2003 the Company also successfully participated in various onshore federal and state lease sales and acquired interests in other prospective acreage. As of December 31, 2003, the Company held interests in approximately 484,000 (256,000 net) acres onshore in the United States.

International Operations

The Company has conducted international exploration activities since the late 1970's in numerous oil and gas areas throughout the world. The Company currently holds licenses in the Kingdom of Thailand, Hungary, the Danish sector of the North Sea and New Zealand. In addition, the Company's international explorationists continue to evaluate other international opportunities that are consistent with its international exploration strategy and expertise.

Substantial portions of the Company's international operations are grouped under its wholly owned Dutch subsidiary, Pogo Overseas Production B.V. Two subsidiaries of Pogo Overseas Production B.V., Thaipo Limited ("Thaipo") and Pogo Hungary Ltd. ("Pogo Hungary"), maintain offices in Bangkok, Thailand and in Budapest, Hungary, respectively.

Exploration and Development

The Company's international capital and exploration expenditures were approximately $138,000,000 for 2003, or 34% higher than comparable expenditures for 2002, and 97% higher than comparable expenditures for 2001. The increase in the Company's capital and exploration expenditures for 2003 resulted primarily from expenditures for facilities costs, including construction of eight platforms for installation in the Thailand Concession, increased drilling expenses resulting from having two rigs drilling in Thailand for a substantial portion of the year and the costs of the initial phase of drilling, all or a portion of, four wells in Hungary.

The Company has currently budgeted approximately $153,000,000 for capital and exploration expenditures during 2004 in areas outside the United States, including $115,000,000 in Thailand and $37,000,000 in Europe, of which approximately $5,700,000 is designated for the Danish sector of the North Sea and the remainder is primarily designated for the Company's operations in Hungary. In addition, the Company has budgeted approximately $1,000,000 for 2004 for its international new venture operations in New Zealand and elsewhere. Of this $153,000,000, approximately $63,400,000 is budgeted for facilities upgrades and additions in the Kingdom of Thailand, including the completion and installation of five platforms on the Thailand Concession, the ordering of steel for another five platforms that are projected to be installed on the Thailand Concession in late 2005, and facilities related to the development of Pogo Hungary's Szolnok No. 2 discovery.

Asia and Pacific Region

The Company currently owns, directly or indirectly, a 46.34% working interest in the entire Thailand Concession. The remainder of the working interest is primarily owned, directly or indirectly, by subsidiaries of ChevronTexaco Corporation, including Chevron Offshore (Thailand) Limited ("Chevron"), Palang Sophon Two Limited, and Palang Sophon Limited ("Palang"). Through its majority ownership of Palang, Chevron owns or controls, directly or indirectly, 53.66% of the working interests in the Thailand Concession and is currently the operator of the Thailand Concession. Through voting procedures in the joint operating agreement governing the Thailand Concession, and the close working relationship between Chevron's and Thaipo's exploration staffs, Thaipo exerts substantial influence over the development of the Thailand Concession. As of December 31, 2003, the Company's proved reserves located in the Kingdom of Thailand accounted for approximately 23% of the Company's total proved reserves. During 2003, approximately 29% of the Company's natural gas production and 33% of its oil and condensate production came from its operations on the Thailand Concession, contributing approximately 26% of the Company's consolidated oil and gas revenues.

Benchamas Field. A portion of the Thailand Concession comprising approximately 102,000 acres is designated as the Benchamas and Pakakrong production area or the "Benchamas Field." In January 2004, the government of Thailand designated approximately 31,000 additional acres as the North Benchamas area. This area is considered a part of, and is being developed in conjunction with, the remainder of the Benchamas Field. By the end of 2004, there are expected to be 14 production platforms installed in the Benchamas Field. Natural gas and oil from these platforms are delivered by undersea pipeline to a central processing and compression platform where the oil, condensate and natural gas is processed and separated. The natural gas is sold to PTT Public Company Limited ("PTT") and delivered into export pipelines for transportation to shore, while the crude oil and condensate produced from the field is stored on board a Floating Storage and Offloading system ("FSO") known as the "Benchamas Explorer" for sale and ultimate transfer to shore by oil tanker. (Please reference section entitled "2004 Production Outlook" for a description of temporary shut-in for the Benchamas Field.) The FSO is moored in the Benchamas Field. Its capacity is approximately 1,400,000 Bbls of crude oil and condensate. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Crude Oil and Condensate Production." Additional drilling is currently planned for the Benchamas Field during 2004. A temporary shutdown of the Benchamas Field to upgrade the Benchamas central processing platform commenced in January and was recently completed. Operations are currently underway to establish full production from all producing wells in the field. During 2003, an additional 24 productive development wells and one successful exploration well were drilled in the Benchamas Field. For 2004, an active drilling campaign is currently planned in the field.

Tantawan Field. A portion of the Thailand Concession comprising approximately 68,000 acres is designated as the Tantawan production area or the "Tantawan Field." Oil and gas production from the Tantawan Field is gathered through pipelines from the platforms into a Floating Production Storage and Offloading system (an "FPSO") named the "Tantawan Explorer." The FPSO is a converted oil tanker with a capacity of slightly less than 1,000,000 Bbls, and is moored in the Tantawan Field, on which hydrocarbon processing, separation, dehydration, compression, metering and other production-related equipment is installed. Following processing on board the FPSO, natural gas produced from the field is delivered to PTT through an export pipeline. Oil and condensate produced from the field is stored on board the FPSO until sold and transferred to shore by oil tanker. See "Management's Discussion and Analysis of Financial Condition and Results of Operations." During 2003, a new platform was set on the western side of the Tantawan Field. In early 2004, eight productive wells were drilled from this platform. In addition, during 2003, ten development and two exploratory wells were drilled in the field. Currently, there is production from six platforms. Current plans call for additional development and exploratory drilling within the field during 2004. During the fourth quarter of 2003, an additional 20,000 acres, comprising the adjacent Block 9A, were assigned to Thaipo and its joint venture partners. Two successful exploration wells were promptly drilled and a production area designation has been applied for. If and when Block 9A is designated a production area, it will be developed from and through existing Tantawan Field facilities, but will require the setting of at least one additional platform.

Maliwan Field. Approximately 91,000 acres of the Thailand Concession are designated as the Maliwan production area or the "Maliwan Field." The Maliwan "A" platform was installed and commenced production on October 29, 2001. An additional seven development wells were drilled from this platform in late 2003. Production from this platform is delivered to the central Benchamas Field production handling facilities for processing and sale. During 2003, two appraisal wells were also drilled in the field and current plans call for additional appraisal drilling in the Maliwan Field during 2004 in connection with finalizing a development plan for the entire field.

Jarmjuree Field. Approximately 124,000 acres of the Thailand Concession, known as the Jarmjuree Field, are designated as a production area. The first platform in this field, the North Jarmjuree "A" platform, is anticipated to be set in the second quarter of 2004. Development drilling and initial production from the Jarmjuree Field is currently expected to occur in 2004. Production from this platform is planned

to be delivered to the central Benchamas Field production handling facilities for processing and sale. Development plans for the remainder of the field are still being formulated. Additional exploration and appraisal wells could be drilled in the Jarmjuree Field and surrounding areas during 2004.

Other Portions of the Thailand Concession. Thaipo and its joint venture partners have identified other potentially promising areas on the Thailand Concession and surrounding acreage. During 2003, Thaipo and its joint venture partners drilled six exploratory wells and have currently budgeted to drill an additional six exploratory wells during 2004. Interpretation of the data provided by these wells and 3-D seismic data covering the Thailand Concession is ongoing.

Platforms are installed on the Thailand Concession in fields where, in the judgment of Thaipo and its joint venture partners, the necessary capital expenditures are justified. A decision to install a platform generally is made after the drilling of one or more exploratory wells with contracted drilling equipment and the area where the platform would be located has been designated a production area by the government of the Kingdom of Thailand. See "Contractual Terms Governing the Thailand Concession and Related Production." Platforms are used to accommodate both development drilling and additional exploratory drilling. A key focus of Thaipo and its joint venture partners has been to reduce the average cost of the platforms installed to improve the overall economics of the project. The gross cost of the fourteen production platforms and related facilities installed in the Tantawan, Benchamas and Maliwan Fields first averaged approximately $17,400,000 per platform. The gross cost of "second generation" platforms, including the three that were installed in 2003 and the five that are under construction, is currently expected to average approximately $15,200,000 per platform. Efforts are currently underway to design and construct even less expensive platforms as part of the next generation to be ordered in 2004. Platform costs vary, and more (or less) expensive platforms could be required in the future depending on, among other factors, the number of slots, water depth, ocean currents and sea floor conditions and the amount of facilities required to be placed on the platform.

Contractual Terms Governing the Thailand Concession and Related Production

The Thailand Concession was granted in August 1991. The initial exploratory term for the Thailand Concession expired on July 31, 2000. However, through a series of one-year extensions, Thaipo and its joint venture partners have been granted an extension of the exploratory term through July 31, 2004. A similar one-year extension will also be applied for to extend the exploratory term of the Thailand Concession through July 31, 2005. This will be the last extension that can be obtained. On July 31, 2005, all acreage for which production area status has not been applied for will revert to the government of Thailand. For those portions of the Thailand Concession that have been designated as production areas, the initial production period term is 20 years, which is also subject to extension, generally for a term of ten years. In November 2003, Thaipo and its joint venture partners requested that the government designate Block 9A as a production area. To date, the Benchamas Field (including the North Benchamas area), Tantawan Field, Maliwan Field and North Jarmjuree Field have been designated as production areas. Subject to governmental approval, other portions of the Thailand Concession may be designated production areas in the future.

Production resulting from the Thailand Concession is generally subject to a royalty ranging from 5% to 15% of oil and gas sales. Slightly different terms apply to production from Block 9A, but the difference is not expected to be material to the results of operations of the Company. Profits from production in Thailand are also subject to a Special Remuneration Benefit ("SRB"). The SRB rate, which can range from 20% to 75%, is calculated based on a complex formula using discounted revenue, meters drilled and other factors specified in the Thailand Concession license agreement. This rate is then applied toward the net proceeds derived by each joint venture partner's Thailand subsidiaries. SRB payments are then treated as a deductible expense for Thailand income tax calculations by such subsidiaries. The Company began accruing SRB liabilities in 2003 on a portion of the net proceeds it derives from the Thailand Concession and currently expects to make significant SRB payments during 2004. See "Management's Discussion and

Analysis of Financial Condition and Results of Operations Results of Operations: Production and Other Taxes."

Thaipo and its joint venture partners have entered into a thirty-year Gas Sales Agreement with PTT (the "Gas Sales Agreement"), governing gas production from the Tantawan Field and the Benchamas Field. The terms of the Gas Sales Agreement currently include a minimum daily contract quantity ("DCQ") of 125 MMcf per day, subject to certain exceptions, and will in the future be based on a percentage of the remaining proved reserves, but in any event will not be less than 125 MMcf per day. In addition, the Gas Sales Agreement gives PTT the right to nominate in any given week 115% of DCQ or approximately 145 MMcf per day. The Gas Sales Agreement provides that PTT may take up to an additional approximate 177 billion cubic feet of gas through December 31, 2007 at production rates that, until the end of such supplemental period ("Supplemental DCQ"), equates to 85 MMcf per day or approximately 40 MMcf net to the Company. During 2003, gas production averaged approximately 224 MMcf per day (90 MMcf per day net to the Company).

Thaipo and its joint venture partners are subject to penalties if they are unable to meet the DCQ or the Supplemental DCQ under the Gas Sales Agreement. Failure to meet DCQ results in a decrease in the sales price for gas sold under the Gas Sales Agreement of up to 25% of the then-current sales price and failure to meet the Supplemental DCQ will result in a credit against the next month's supplemental production of 12% (6% from March 1, 2004 through January 1, 2006) of the then-current sales price of the gas not delivered. Thaipo currently meets the minimum DCQ and generally meets the Supplemental DCQ requirements, however, there can be no assurance that Thaipo will be able to continue to meet them in the future, in which case these penalty provisions would reduce the price received by Thaipo for its gas sold to PTT under the Gas Sales Agreement.

The sales price for the base DCQ production under the Gas Sales Agreement is subject to automatic semi-annual adjustments based upon a formula that takes into account changes in: Singapore fuel oil prices; the U.S. Bureau of Labor Statistics Oilfield Machinery and Tool Index; the Thai wholesale producer price index; and the U.S./Thai currency exchange rate. However, the Gas Sales Agreement provides for adjustment on a more frequent basis in the event that certain indices and factors on which the price is based fluctuate outside a given range. The sales price for Supplemental DCQ production is 88% of the then-current sales price for DCQ production. As of December 31, 2003, the Company was receiving a blended average price of approximately $2.59 per Mcf under the Gas Sales Agreement for DCQ and Supplemental DCQ production. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Results of Operations" and "Liquidity and Capital Resources; Other Matters; Southeast Asia Economic Issues."

Other Areas of the World

Hungary. On April 20, 1999, the Company's subsidiary, Pogo Hungary, was awarded a license to explore for oil and gas in the Szolnok and Tompa areas of central and south central Hungary. This license area currently consists of approximately 764,000 acres. The exploration term of the license is currently set to expire on April 19, 2005, with further extension possible until April 19, 2007 with government approval. Areas where commercial accumulation of hydrocarbons are identified may then be designated as "mining plots" and held through the economic productive life of such reserves. One 3-D survey covers approximately 97,000 acres, a substantial portion of the Tompa area, and the other covers approximately 42,000 acres of the Szolnok area and is referred to as the Kenderes 3-D survey. Based upon detailed evaluation of this 3-D seismic data and extensive other data acquired from government sources, a number of prospects have been preliminarily identified. During 2003, Pogo Hungary drilled two wells in the Szolnok area, including the Szolnok No. 2 well that was successfully tested and another well that has been temporarily abandoned to allow for possible future testing. Pogo Hungary also drilled three wells in the Tompa area, which have been temporarily abandoned pending possible fracture stimulation or additional testing. Pogo Hungary currently intends to drill additional exploration wells during 2004, as well as

delineation wells on the Szolnok No. 2 discovery. Pogo Hungary also currently intends to acquire additional seismic data during 2004 in the Szolnok area and to continue analyzing its existing 2-D and 3-D seismic database.

Hungary imported approximately 80% of the crude oil and approximately 77% of the natural gas that it consumed in 2002. Most of the natural gas that is imported into Hungary comes from Russia. The remaining imported natural gas is delivered from Austria through the HAG pipeline. Historically, the domestic Hungarian oil and gas industry was entirely state-owned. Due to privatization of the industry, the Hungarian retail petroleum market was liberalized in 1991. The wholesale and retail prices for natural gas remained heavily regulated and partially subsidized until late 2003. Currently, the Company believes that crude oil produced in Hungary may be sold in Hungary or exported at a price based upon world market prices. The sale of natural gas in Hungary was recently liberalized under an amendment to the Hungarian Natural Gas Act. Effective January 1, 2004, industrial consumers are eligible to purchase gas in the free market. The residential consumer market is anticipated to continue to be served by a public utility wholesale provider at regulated prices until no later than 2007 in accordance with European Economic Union regulations. Pogo Hungary also currently believes that, in addition to supplying gas to eligible consumers in the domestic market, it has the ability to swap the natural gas it produces in Hungary for natural gas at the Baumgarten hub in Austria, which can then be sold at unregulated European spot prices, or to export the gas to surrounding countries.

North Sea. On August 5, 1999, the Danish government approved the assignment to the Company of a 40% working interest in License 13/98 covering approximately 81,000 acres in the Danish sector of the North Sea. This license interest is currently held by the Company's Danish subsidiary, Pogo Denmark ApS. The work commitment for this license requires the drilling of an exploratory well prior to the expiration of the license. The initial term of the license goes through June 14, 2004, unless otherwise extended or a production license is granted. Pogo Denmark ApS and its joint venture partners have scheduled and intend to drill a well during the first half of 2004 on one of the prospects that has been identified on the block.

During 2003, Pogo North Sea Limited, a British subsidiary of the Company, together with two joint venture partners, held a license governing approximately 113,000 acres in the British sector of the North Sea. Pending final government approval, and as of December 23, 2003, the joint venture has relinquished its interest in the license area back to the Department of Trade and Industry.

New Zealand. On February 4, 2004, the Company was granted three petroleum exploration licenses (the "Licenses") over approximately 1,014,000 acres in the offshore Northern Taranaki Basin. The primary exploration term of the Licenses is for five years, subject to extension up to an additional ten years, provided that at least half of the acreage under each license has been relinquished and the permit holder has substantially complied with the terms of its permits. The Company has committed to acquire 3-D seismic data over at least 1,000 square kilometers of the Licenses within the first two years of their primary term. Based upon an analysis of this data, the Company has a contingent commitment to drill one well on each of the three Licenses by the end of 2007. Production permits of up to 40 years may be applied for if a commercial field is discovered. The Company's current plans for 2004 consist of evaluating existing data and designing a 3-D seismic acquisition program over prospective portions of the Licenses.

Geographic Information

For financial information about geographic areas, see Note 6 Geographic Segment Information in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

Miscellaneous

Other Assets

The Company and a subsidiary, Pogo Offshore Pipeline Co., own interests in eight pipelines (excluding field gathering pipelines) through which offshore hydrocarbon production is transported. As previously discussed, the Company also owns an approximate 15% interest in the Lost Cabin Gas Plant located in the Madden Field, which currently has the capacity to process 313 MMcf of natural gas per day.

Sales

The marketing of all of the Company's onshore and offshore oil and gas production is subject to the availability of pipelines and other transportation, processing and refining facilities, as well as the existence of adequate markets. As a result, even if hydrocarbons are discovered in commercial quantities, a substantial period of time could elapse before commercial production commences. If pipeline facilities in an area are insufficient, the Company may have to await the construction or expansion of pipeline capacity before production from that area can be marketed. The Company's domestic onshore and offshore properties are generally located in areas where a pipeline infrastructure or other transportation alternatives are well developed and there is adequate availability in such pipelines or other transportation alternatives to transport the Company's current and projected future production.

The Company may not be able to successfully market all of the oil and natural gas found and produced on the Thailand Concession. Currently, the only purchaser of natural gas is PTT, which maintains a monopoly over gas transmission and distribution in Thailand, including ownership of the two major natural gas pipelines (34 inches and 36 inches in diameter, respectively) that traverse the Thailand Concession. All oil and condensate production from the Tantawan Field is initially stored aboard the FPSO and then sold to various third parties, including PTT, on a tanker load by tanker load basis at prices based on then-current world oil prices, typically with reference to the Malaysian Tapis Blend crude oil benchmark price. Crude oil and condensate production from the Benchamas Field and the first platform located in the northern portion of the Maliwan Field is initially stored aboard the FSO. A portion of this production is sold under a term sales agreement with China International United Petroleum & Chemical Company Ltd. that expires in March 2004. This term sales agreement is for a total of 3,600,000 Bbls (1,668,000 Bbls net to Thaipo) at a price equal to Malaysian TAPIS less $0.40 per Bbl. Another portion of this production is sold under a term sales agreement with Pacific Petroleum and Trading Co., Ltd. that expires in August 2004. This term sales agreement is for 600,000 Bbls per month, subject to seller's availability, at an agreed price each month. The remaining production from the Benchamas Field is sold on a tanker load by tanker load basis, similar to the way Tantawan Field crude oil is currently marketed.

The prices that the Company receives for crude oil sales from its Thailand Concession are influenced by a number of factors including, among others, tanker availability, world-wide crude oil demand, size of the lifting and the perceived quality of crude oil produced. For example, crude oil produced from the Gulf of Thailand is generally perceived as having high mercury levels. The crude oil from the Benchamas Field has high wax content. Therefore, it is sought after by some refineries and is less desirable to others. These factors and others have led to significant fluctuations in the price that the Company receives for its Thai crude oil production in comparison to the Malaysian Tapis Blend benchmark price. During 2003, the price that the Company received for its crude oil production from the Thailand Concession ranged between a $0.75 per Bbl premium and a $1.25 per Bbl discount to the Malaysian Tapis Blend benchmark price. The Company and its joint venture partners continue to examine ways to improve the price received for crude oil, including the possibility of entering into further long-term contracts for a portion of its production. In addition, because much of the oil produced from the Thailand Concession is associated with natural gas, limitations on Thaipo's ability to produce natural gas could limit crude oil production as well. The crude oil purchaser is generally responsible for sending a tanker to offload the oil and condensate it has purchased.

See "International Operations; Contractual Terms Governing the Thailand Concession and Related Production."

Most of the Company's North American natural gas sales are currently made in the "spot market" for no more than one month at a time at then-currently available prices or under longer-term contracts with prices that are based on, and fluctuate with, spot market prices. Prices on the spot market fluctuate with supply and demand. Crude oil and condensate production is also generally sold one month at a time at the price that is then-currently available or under longer-term contracts with prices that also fluctuate in relationship to published market price. Other than any oil and natural gas forward sales contracts that may exist from time to time, and are referred to in "Miscellaneous; Competition and Market Conditions," and the Gas Sales Agreement with PTT for production from the Thailand Concession (see "International Operations; Contractual Terms Governing the Thailand Concession and Related Production") and the crude oil contracts discussed above, the Company has no existing contracts that require the delivery of fixed quantities of oil or natural gas, other than on a best efforts basis. In 2003, crude oil sales to one customer (China International United Petroleum & Chemical Company Ltd.) constituted more than 10% of the Company's consolidated revenues.

Risks Associated with Acquisitions

From time to time the Company acquires, and may acquire in the future, additional interests in oil and gas properties, either through acquisition of the properties themselves or, as in the case of the North Central acquisition, indirectly through the purchase of an equity interest in the entity owning such properties. The successful acquisition of such properties requires an assessment of several factors, including recoverable reserves, development and exploratory potential, projected future cash flows that are, in part, based upon future oil and gas prices, current and projected operating, general and administrative and other costs, and contingent liabilities associated with the properties or entities acquired, including potential environmental and other liabilities.

The accuracy of the Company's assessment of these factors is inherently uncertain. To the extent reasonably practicable under the specific circumstances of each acquisition, the Company performs a review of the properties or entities prior to an acquisition. The Company believes that its review procedures are generally consistent with current industry practices. The Company's review and assessment process will not reveal all existing or potential problems nor will it permit the Company to become sufficiently familiar with the properties or entities to fully assess their deficiencies and capabilities. Even when problems are identified, the other party may be unwilling or unable to provide effective contractual protection against all or part of the problems. Occasionally, the Company may not be entitled to contractual indemnification for certain liabilities, acquiring the properties on an "as is, where is" basis. In addition, successful acquisitions frequently require the successful integration of operations, equipment and personnel. There can be no assurance that the Company will be able to successfully integrate operations and properties that it acquires and still achieve the anticipated synergies, cost savings and efficiencies.

Competition and Market Conditions

The Company experiences competition from other oil and gas companies in all phases of its operations, as well as competition from other energy-related industries. The Company's profitability and cash flow are highly dependent upon the prices of oil and natural gas, which historically have been seasonal, cyclical and volatile. In general, prices of oil and gas are dependent upon numerous factors beyond the control of the Company, including various weather, economic, political and regulatory conditions. In addition, the decisions of the Organization of Petroleum Exporting Countries relating to export quotas also affect the price of crude oil. A future drop in oil or gas prices could have a material adverse effect on the Company's cash flow and profitability. Sustained periods of low prices could cause the Company to shut in existing production and also have a material adverse effect on its operations and financial condition. It could also result in a reduction of funds available under the Company's bank credit

facilities. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources; Credit Facility."

Because it is impossible to predict future oil and gas price movements with any certainty, the Company from time to time enters into contracts to hedge against future market price changes on a portion of its production. Such hedging transactions, historically, have never exceeded 50% of the Company's total oil and gas production on an energy equivalent basis for any given period. While intended to limit the negative effect of price declines, some forms of hedging transactions could effectively limit the Company's participation in price increases, which could be significant, for the covered period. As of December 31, 2003, the Company was not a party to any natural gas or crude oil option contracts. When the Company does engage in certain types of hedging activities, it may satisfy its obligations with its own production or by the purchase (or sale) of third-party production. The Company may also offset delivery obligations under these hedging transactions requiring physical delivery with equivalent agreements, thereby effecting a purely cash transaction.

Operating and Uninsured Risks

The Company's operations are subject to risks inherent in the exploration for and production of oil and natural gas, such as blowouts, cratering, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, pollution and other environmental risks. Offshore oil and gas operations are subject to the additional hazards of marine and helicopter operations, such as capsizing, collision and adverse weather and sea conditions. These hazards could result in substantial losses to the Company due to injury or loss of life, severe damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. The Company carries insurance that it believes is in accordance with customary industry practices, but is not fully insured against all risks incident to its business.

Drilling activities are subject to numerous risks, including the risk that no commercially productive hydrocarbon reserves will be encountered. The cost of drilling, completing and operating wells and of installing production facilities and pipelines is often uncertain. The Company's drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including title problems, weather conditions, compliance with governmental requirements and shortages or delays in the delivery or availability of material, equipment and fabrication yards. In periods of increased drilling activity resulting from high commodity prices, demand exceeds availability for drilling rigs, drilling vessels, supply boats and personnel experienced in the oil and gas industry in general, and the offshore oil and gas industry in particular. For example, the Company is currently experiencing some difficulty in obtaining additional drilling rigs for its Thailand operations due to the lack of suitable rigs in the region. This may lead to difficulty and delays in consistently obtaining certain services and equipment from vendors, obtaining drilling rigs and other equipment at favorable rates and scheduling equipment fabrication at factories and fabrication yards. This, in turn, may lead to projects being delayed or experiencing increased costs.

In periods during which the industry experiences a substantial decline in oil and gas prices, many of the Company's partners, particularly the smaller ones, can experience liquidity and cash flow problems. These problems may lead to the smaller companies' attempts to delay or slow down the pace of drilling or project development in order to conserve cash, to a point that the Company believes is detrimental to the project. In most cases, the Company has the ability to influence the pace of development through joint operating agreements. Some partners may be unwilling or unable to pay their share of the costs of projects as they become due. At worst, a partner may declare bankruptcy and refuse or be unable to pay its share of the costs of a project. The Company would then be required to pay this partner's share of the project costs. In most instances, the Company believes that it is contractually protected from such an event through its ability to take over the non-paying partner's share of the project and by applicable oil and gas lien laws and bankruptcy laws. The Company believes that it would ultimately recover any sums that it is owed by non-paying partners that do not meet their share of the costs of a project in a timely fashion.

Risks of Foreign Operations

Ownership of property interests and production operations in Thailand, Hungary, the North Sea, New Zealand and in any other areas outside the United States in which the Company may choose to do business are subject to the various risks inherent in foreign operations. These risks may include, among other things, currency restrictions and exchange rate fluctuations, loss of revenue, property and equipment as a result of hazards such as expropriation, nationalization, war, insurrection and other political risks, risks of increases in taxes and governmental royalties, renegotiation of contracts with governmental entities, changes in laws and policies governing operations of foreign-based companies and other uncertainties arising out of foreign government sovereignty over the Company's international operations. See "Management's

Discussion and Analysis of Financial Condition and Results of Operations," and "Liquidity and Capital Resources; Other Matters; Southeast Asia Economic Issues." The Company's international operations may also be adversely affected by laws and policies of the United States affecting foreign trade, taxation and investment. In addition, in the event of a dispute arising from foreign operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of the courts of the United States. The Company seeks to manage these risks by concentrating its international exploration efforts in areas where the Company believes that the existing government is stable and favorably disposed towards United States exploration and production companies.

Exploration and Production Data

In the following data, "gross" refers to the total acres or wells in which the Company has an interest and "net" refers to gross acres or wells multiplied by the percentage working interest owned by the Company.

Acreage

The Company owns interests in developed and undeveloped oil and gas acreage in various parts of the world. These ownership interests generally take the form of "working interests" in oil and gas leases that

have varying terms. The following table shows the Company's interest in developed and undeveloped oil and gas acreage under lease as of December 31, 2003:

	Developed Acreage(a)		Undeveloped Acreage(b)	
	Gross	Net	Gross	Net
Domestic Offshore				
Louisiana	142,126	52,498	137,604	101,324
Texas	17,280	6,141	23,040	5,904
Total Domestic Offshore	159,406	58,639	160,644	107,228
Domestic Onshore				
Louisiana	9,407	2,577	9,334	3,279
Mississippi	1,280	26		
New Mexico	54,357	38,505	74,879	57,510
Texas	185,262	85,950	63,523	41,909
Wyoming	29,205	3,700	50,614	20,287
Other	6,120	2,211	80	15
Total Domestic Onshore	285,631	132,969	198,430	123,000
Total Domestic	445,037	191,608	359,074	230,228
International				
Gulf of Thailand	415,824	192,698	318,444	147,572
North Sea			81,000	32,400
Hungary			764,315	764,315
Total International	415,824	192,698	1,163,759	944,287
Total Company	860,861	384,306	1,522,833	1,174,515

	Developed Acreage(a)		Undeveloped Acreage(b)	

(a) "Developed acreage" consists of lease acres spaced or assignable to production (including acreage held by production) on which wells have been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas. "Developed acreage" in Thailand includes all acreage designated as a production area by the Thai government, which currently includes Benchamas, North Benchamas Tantawan, Maliwan and Jarmjuree production licenses.

(b) Approximately 3.4% of the Company's total domestic offshore net undeveloped acreage is under leases that have minimum terms expiring in 2004 and another 1% expires in 2005. Approximately 21% of the Company's total domestic onshore net undeveloped acreage is under leases with minimum terms expiring in 2004 and another 12% expires in 2005. All of the Company's undeveloped acreage in the Kingdom of Thailand has an exploratory term expiring July 31, 2004, subject to one further one-year lease extension that may be applied for to extend the exploratory term through July 31, 2005. See "International Operations; Contractual Terms Governing the Thailand Concession and Related Production."

In addition, the Company holds a 100% interest in 1,014,000 undeveloped acres in New Zealand that were granted in February 2004, as well as certain other types of mineral interests, including fee interests (which never expire) and royalty interests (which generally terminate when the underlying mineral lease expires). The Company owns varying fee and royalty interests in approximately 1,190,600 gross acres (26,875 net acres) in various parts of the United States, principally as a result of the North Central acquisition.

Average Production (Lifting) Costs per Unit of Production

The following table shows the average production (lifting) costs per unit of production during the periods indicated. For a discussion of the Company's average daily production and the average sales prices received by the Company for such production, see "Selected Financial Data Production (Sales) Data" and

"Management's Discussion and Analysis of Financial Condition and Results of Operations Results of Operations; Oil and Gas Revenues."

	2003	2002	2001
Average Production (Lifting) Costs per Mcfe(a)(b):			
Located in the United States	$ 0.68	$ 0.69	$ 0.81
Located in the Kingdom of Thailand	$ 0.67	$ 0.59	$ 0.65
Total Company	$ 0.68	$ 0.66	$ 0.76

(a) Production costs were converted to common units of measure on the basis of relative energy content. Such production costs exclude all depletion, depreciation and amortization associated with property and equipment. Production costs for the Company's Canadian operations, which were sold effective August 31, 2001 as part of an asset rationalization process, are included in United States production costs for the year. Average production (lifting) costs in Canada, prior to the sale, were $1.37 in 2001.

(b) Reclassifications of certain product transportation costs have been made to prior year amounts to conform with current year presentation.

Productive Wells and Drilling Activity

The following table shows the Company's interest in productive oil and natural gas wells as of December 31, 2003. For purposes of this table "productive wells" are defined as wells producing hydrocarbons and wells "capable of production" (e.g., natural gas wells waiting for pipeline connections or necessary governmental certification to commence deliveries and oil wells waiting to be connected to currently installed production facilities). "Net wells" for purposes of this table are defined to mean the sum of the Company's working interest net of royalties and other burdens. This table does not include exploratory or development wells which have located commercial quantities of oil or natural gas but which are not capable of commercial production without the installation of material production facilities or which, for a variety of reasons, the Company does not currently believe will be placed on production.

	Oil Wells(a)(b)		Natural Gas Wells(a)(b)	
	Gross	**Net**	**Gross**	**Net**
Domestic Offshore	143	45.80	66	22.45
Domestic Onshore	937	658.90	944	457.07
Kingdom of Thailand	87	40.30	55	25.50
Hungary			1	1.00
Total	1,167	745.00	1,066	506.02

(a)
One or more completions in the same bore hole are counted as one well. The data in the above table includes 9 gross (3.66 net) oil wells and 22 gross (10.50 net) natural gas wells with multiple completions.

(b)
The Company was in the process of drilling a total of 4 gross (0.34 net) oil wells and 17 gross (10.61 net) natural gas wells as of December 31, 2003.

The following table shows the number of successful gross and net exploratory and development wells in which the Company has participated and the number of gross and net wells abandoned as dry holes during the periods indicated. An onshore well is considered successful upon the installation of permanent equipment for the production of hydrocarbons or when electric logs run to evaluate such wells indicate the presence of commercially producible hydrocarbons and the Company currently intends to complete such

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wells. Successful offshore wells consist of exploratory or development wells that have been completed or are "suspended" pending completion (which has been determined to be feasible and economic) and exploratory test wells that were not intended to be completed and that encountered commercially producible hydrocarbons. A well is considered a dry hole when the Company decides to report permanent abandonment to the appropriate agency.

	2003		2002		2001	
	Productive	**Dry**	**Productive**	**Dry**	**Productive**	**Dry**
Gross Wells:						
Offshore United States						
Exploratory	5.0	2.0	5.0	2.0	2.0	3.0
Development	3.0		13.0		22.0	
Onshore North America(a)						
Exploratory	9.0	3.0	1.0	4.0	7.0	3.0

	2003		2002		2001	
Development	169.0	9.0	83.0	5.0	61.0	3.0
Offshore Kingdom of Thailand						
Exploratory	5.0	1.0	6.0		11.0	
Development	40.0	1.0	51.0	2.0	18.0	
Europe						
Exploratory	1.0					
Development						
Total	232.0	16.0	159.0	13.0	121.0	9.0
Net Wells:						
Offshore United States						
Exploratory	2.3	2.0	5.0	2.0	2.0	1.7
Development	2.2		8.8		8.3	
Onshore North America(a)						
Exploratory	5.9	2.0	0.8	3.2	5.0	1.3
Development	75.9	3.5	54.7	3.4	38.0	1.6
Offshore Kingdom of Thailand						
Exploratory	2.3	0.5	2.8		5.1	
Development	18.5	0.5	23.5	0.9	8.3	
Europe						
Exploratory	1.0					
Development						
Total	108.1	8.5	95.6	9.5	66.7	4.6

(a) The Company's operations in Canada were sold effective August 31, 2001 as part of an asset rationalization program. Onshore North America wells drilled in 2001 reflect wells drilled in Canada by the Company prior to the sale of these operations.

Reserves

The following table sets forth information as to the Company's net proved and proved developed reserves as of December 31, 2003, 2002 and 2001, and the present value as of such dates (based on an annual discount rate of 10%) of the estimated future net revenues from the production and sale of those reserves, as set forth in reports prepared by Ryder Scott Company L.P. ("Ryder Scott") and Miller and Lents, Ltd. ("Miller and Lents"), the Company's independent petroleum engineers, in accordance with criteria prescribed by the Commission. The summary reports of Ryder Scott and Miller and Lents on the Company's reserves are set forth as exhibits to this Annual Report on Form 10-K and are incorporated herein by reference. The Ryder Scott report covers the Company's reserves except for certain domestic onshore areas acquired in the North Central acquisition.

The Company does not currently believe that the calculation of estimated future net revenues using the assumptions prescribed by Commission guidelines and generally described below is representative of the true value of future net revenues from the Company's proved reserves. The future prices received by the Company for the sales of its production may be higher or lower than the prices used in calculating the estimates of future net revenues, and the operating costs and other costs relating to such production may also increase or decrease from existing levels.

	As of December 31,		
	2003	2002	2001
Total Proved Reserves:			
Oil, condensate and natural gas liquids (MBbls)			
Located in North America	77,553	80,092	79,979
Located in the Kingdom of Thailand	37,307	38,087	39,301
Located in Hungary	10		
Total Company	114,870	118,179	119,280
Natural Gas (MMcf)			
Located in North America	837,004	713,906	670,567
Located in the Kingdom of Thailand	165,188	159,604	148,225
Located in Hungary	10,131		
Total Company	1,012,323	873,510	818,792
Present value of estimated future net revenues, before income taxes (in thousands)			
Located in North America	$ 2,928,663	$ 2,495,558	$ 1,130,353
Located in the Kingdom of Thailand	744,822	602,798	410,307
Located in Hungary	16,516		
Total Company	$ 3,690,001	$ 3,098,356	$ 1,540,660
Total Proved Developed Reserves:			
Oil, condensate and natural gas liquids (MBbls)			
Located in North America	67,391	74,041	59,383
Located in the Kingdom of Thailand	19,878	23,832	20,394
Located in Hungary			
Total Company	87,269	97,873	79,777
Natural Gas (MMcf)			
Located in North America	702,836	600,255	532,348
Located in the Kingdom of Thailand	77,938	87,301	69,997
Located in Hungary			
Total Company	780,774	687,556	602,345
Present value of estimated future net revenues, before income taxes (in thousands)			
Located in North America	$ 2,455,495	$ 2,239,781	$ 951,040
Located in the Kingdom of Thailand	458,511	422,219	241,860
Located in Hungary			
Total Company	$ 2,914,006	$ 2,662,000	$ 1,192,900

The Company believes, for the reasons set forth in succeeding paragraphs, that the present value of estimated future net revenues set forth in the Annual Report and calculated in accordance with

Commission guidelines is not necessarily indicative of the true fair value of the Company's reserves. Moreover, due to the fact that essentially all of the Company's domestic natural gas production is currently sold on the spot market, while all of the Company's Thailand natural gas production is sold pursuant to a long-term gas sales contract, the estimates of future net revenues from the Company's domestic and Thailand reserves are of limited value for comparative purposes.

Natural gas liquids comprised approximately 5% of the Company's total proved liquids reserves and approximately 5% of the Company's proved developed liquids reserves as of December 31, 2003. All hydrocarbon liquid reserves are expressed in standard 42 gallon Bbls. All gas volumes and gas sales are expressed in MMcf at the pressure and temperature bases of the area where the gas reserves are located.

In accordance with Commission guidelines, the prices used by the Company to calculate the present value of estimated future revenues are determined on a well or field-by-field basis, as applicable, as described above and were held constant over the productive life of the reserves. The initial weighted average prices used by Ryder Scott and Miller & Lents were as follows:

	As of December 31,		
	2003	**2002**	**2001**
Initial Weighted Average Price (in Dollars):			
Oil, condensate and natural gas liquids (per Bbl)			
Located in North America(a)	$ 31.34	$ 28.72	$ 18.75
Located in the Kingdom of Thailand	$ 30.27	$ 32.41	$ 18.94
Located in Hungary	$ 26.00	$	$
Natural Gas (per Mcf)			
Located in North America(a)	$ 5.70	$ 4.70	$ 2.48
Located in the Kingdom of Thailand	$ 2.51	$ 2.24	$ 2.31
Located in Hungary	$ 4.82	$	$

(a) The Company sold its operations and reserves in Canada effective August 31, 2001 as part of an asset rationalization process.

In computing future revenues from gas reserves attributable to the Company's domestic interests, prices in effect at December 31, 2003 were used, including current market prices, contract prices and fixed and determinable price escalations where applicable. In accordance with Commission guidelines, the gas prices that were used make no allowances for seasonal variations in gas prices that are likely to cause future yearly average gas prices to be different than December gas prices. For domestic gas sold under contract, the contract gas price including fixed and determinable escalations, exclusive of inflation adjustments, was used until the contract expires and then was adjusted to the current market price for the area and held at this adjusted price through to depletion of the reserves. In computing future revenues from liquids attributable to the Company's domestic interests, prices in effect at December 31, 2003 were used and these prices were held constant through to depletion of the properties. The future net revenues are adjusted to reflect the Company's net revenue interest in these reserves as well as any ad valorem and other severance taxes but do not include any provisions for corporate income taxes.

In computing future revenues from the Company's gas reserves attributable to the Company's interests in the Kingdom of Thailand, a blended price that took into account the current contract price under the Gas Sales Agreement for the base production (currently 145 MMcf per day) and the price for excess sales volumes (which equals 88% of the then-current price for base production) was used, without giving effect to any of the future adjustments provided for in the Gas Sales Agreement, due to their indeterminate nature as of December 31, 2003, in accordance with Commission guidelines. In computing future revenues from liquids attributable to the Company's interests in the Kingdom of Thailand, a price

was used that the Company believes approximates the price that the Company would have received for its production from the Thailand Concession based upon the world market price for Malaysian Tapis Blend benchmark crude on December 31, 2003, and this price was held constant until depletion of the Company's reserves in the Kingdom of Thailand. The future net revenues are adjusted to reflect the Company's net revenue interest in these reserves and the Company's obligations under the Thailand Concession, including the payment of SRB, but do not include any provisions for U.S. or Thai corporate income or other taxes.

In accordance with Commission guidelines for calculating future net revenues, the operating costs for the leases and wells include only those costs directly applicable to the leases or wells. When applicable, the operating costs include a portion of general and administrative costs allocated directly to the leases and wells under terms of operating agreements. Development costs are based on authorization for expenditure for the proposed work or actual costs for similar projects. The current operating and development costs were held constant throughout the life of the properties. The estimated net cost of abandonment after salvage was considered for the properties. No deduction was made for indirect costs such as general and administrative and overhead expenses, loan repayments, interest expenses and exploration and development prepayments. Accumulated gas production imbalances, if any, have been taken into account.

Production data used to arrive at the estimates set forth above includes estimated production for the last few months of 2003. The future production rates from reservoirs now on production may be more or less than estimated because of, among other reasons, mechanical breakdowns and changes in market demand or allowables set by regulatory bodies. Properties that are not currently producing may start producing earlier or later than anticipated in the estimates of future production rates.

There are numerous uncertainties in estimating the quantity of proved reserves and in projecting the future rates of production and timing of development expenditures. Oil and gas reserve engineering must be recognized as a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way, and estimates of other engineers might differ materially from those of the Company, Ryder Scott and Miller & Lents. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate, which may be material. Accordingly, reserve estimates are often different from the quantities of oil and gas that are ultimately recovered.

The Company is periodically required to file estimates of its oil and gas reserve data with various U.S. governmental regulatory authorities and agencies, including the Department of Energy, the Federal Energy Regulatory Commission ("FERC") and the Federal Trade Commission and, with respect to reserves located in Thailand, the Kingdom of Thailand's Department of Mineral Fuels and PTT, which the Company considers a quasi-governmental authority. In addition, estimates are from time to time furnished to governmental agencies in connection with specific matters pending before such agencies. The basis for reporting reserves to these agencies, in some cases, is not comparable to that furnished by Ryder Scott and Miller & Lents in accordance with Commission guidelines because of the nature of the various reports required. The major differences generally include differences in the timing of such estimates, differences in the definition of reserves, requirements to report in some instances on a gross, net or total operator basis and requirements to report in terms of smaller geographical units. Since January 1, 2003, no estimates by the Company of its total proved net oil or gas reserves were filed with or included in reports to any Federal authority or agency other than the Commission.

Government Regulations

Federal Income Tax

Federal income tax laws significantly affect the Company's operations. The principal provisions affecting the Company are those that permit the Company, subject to certain limitations, to deduct as incurred, rather than to capitalize and amortize, its domestic "intangible drilling and development costs" and to claim depletion on a portion of its domestic oil and gas properties based on 15% of its oil and gas gross income from such properties (up to an aggregate of 1,000 Bbls per day of domestic crude oil and/or equivalent units of domestic natural gas), even though the Company has little or no basis in such properties. Under certain circumstances, however, a portion of such intangible drilling and development costs and the percentage depletion allowed in excess of basis will be tax preference items that will be taken into account in computing the Company's alternative minimum tax.

Environmental Matters

Domestic oil and gas operations are subject to extensive federal regulation and, with respect to federal leases, to interruption or termination by governmental authorities on account of environmental and other considerations such as the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") also known as the "Superfund Law." The trend towards stricter standards in environmental legislation and regulation could increase costs to the Company and others in the industry. Oil and gas lessees are subject to liability for the costs of clean-up of pollution resulting from a lessee's operations, and may also be subject to liability for pollution damages. The Company maintains insurance against costs of clean-up operations, but is not fully insured against all such risks. A serious incident of pollution may, as it has in the past, also result in the Department of the Interior requiring lessees under federal leases to suspend or cease operation in the affected area.

The Company has numerous applications pending before the Environmental Protection Agency (the "EPA") for National Pollution Discharge Elimination System ("NPDES") water discharge permits with respect to offshore drilling and production operations. NPDES permits are required to ensure that effluent discharges from each facility or installation comply with the applicable federal regulations.

The Oil Pollution Act of 1990 (the "OPA") and regulations thereunder impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of federal safety, construction or operating regulations. Few defenses exist to the liability imposed by the OPA. In addition, to the extent the Company's offshore lease operations affect state waters, the Company may be subject to additional state and local clean-up requirements or incur liability under state and local laws. The OPA also imposes ongoing requirements on responsible parties, including proof of financial responsibility to cover at least some costs in a potential spill. The amount of financial responsibility that the Company must currently demonstrate for its offshore platforms is $70,000,000. The Company believes that it currently has established adequate proof of financial responsibility for its offshore facilities. However, the Company cannot predict whether these financial responsibility requirements under the OPA amendments will result in the imposition of substantial additional annual costs to the Company in the future or otherwise materially adversely affect the Company. The impact, however, should not be any more adverse to the Company than it will be to other similarly situated or less capitalized owners or operators in the Gulf of Mexico.

The Company's onshore operations are subject to numerous federal, state and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Such laws and regulations, among other things, impose absolute liability on the lessee for the cost of clean-up of pollution resulting from a lessee's operations, subject the lessee to liability for pollution damages, may require suspension or cessation of operations in affected areas, and impose restrictions on the injection of liquids into subsurface aquifers that may contaminate groundwater. Such laws could have a significant impact on the operating costs of the Company, as well as the oil and gas industry in general. Federal, state and local initiatives to further regulate the disposal of oil and gas wastes are also pending in certain jurisdictions, and these initiatives could have a similar impact on the Company. The Company's operations are also subject to additional federal, state and local laws and regulations

relating to protection of human health, natural resources, and the environment pursuant to which the Company may incur compliance costs or other liabilities.

The Company is asked to comment on the costs it incurred during the prior year on capital expenditures for environmental control facilities and the amount it anticipates incurring during the coming year. The Company believes that, in the course of conducting its oil and gas operations, many of the costs attributable to environmental control facilities would have been incurred absent environmental regulations as prudent, safe oilfield practice. During 2003, the Company incurred capital expenditures of approximately $1,987,000 for environmental control facilities, primarily relating to the cost of installing environmental equipment, the installation of pit and firewall spill liners, and routine site restoration costs. The Company has budgeted approximately $2,500,000 for expenditures involving environmental control facilities during 2004, including, among other things, anticipated site restoration costs and the installation of environmental control equipment.

Other Laws and Regulations

Various laws and regulations often require permits for drilling wells and also cover spacing of wells, the prevention of waste of oil and gas including maintenance of certain gas/oil ratios, rates of production and other matters. The effect of these laws and regulations, as well as other regulations that could be promulgated by the jurisdictions in which the Company has production, could be to limit the number of wells that could be drilled on the Company's properties and to limit the allowable production from the successful wells completed on the Company's properties, thereby limiting the Company's revenues.

The MMS administers the oil and gas leases held by the Company on federal onshore lands and offshore tracts in the Outer Continental Shelf. The MMS holds a royalty interest in these federal leases on behalf of the federal government. While the royalty interest percentage is fixed at the time that the lease is entered into, from time to time the MMS changes or reinterprets the applicable regulations governing its royalty interests, and such action can indirectly affect the actual royalty obligation that the Company is required to pay. However, the Company believes that the regulations generally do not impact the Company to any greater extent than other similarly situated producers.

The FERC has embarked on wide-ranging regulatory initiatives relating to gas transportation rates and services, including the availability of market-based and other alternative rate mechanisms to pipelines for transmission and storage services. In addition, the FERC has announced and implemented a policy allowing pipelines and transportation customers to negotiate rates above the otherwise applicable maximum lawful cost-based rates on the condition that the pipelines alternatively offer so-called recourse rates equal to the maximum lawful cost-based rates. With respect to gathering services, the FERC has issued orders declaring that certain facilities owned by interstate pipelines primarily perform a gathering function, and may be transferred to affiliated and non-affiliated entities that are not subject to the FERC's rate jurisdiction. The Company cannot predict the ultimate outcome of these developments, or the effect of these developments on transportation rates. Inasmuch as the rates for these pipeline services can affect the gas prices received by the Company for the sale of its production, the FERC's actions may have an impact on the Company. However, the impact should not be substantially different on the Company than it will on other similarly situated gas producers and sellers.

Employees

As of December 31, 2003, the Company and its subsidiaries had 221 full-time employees, including six in its Bangkok, Thailand office and seven in its Budapest, Hungary office. None of the Company's employees are presently represented by a union for collective bargaining purposes.

Available Information

The Company files annual, quarterly and current reports, proxy statements and other information with the Commission. These filings are available free of charge through its Internet website at www.pogoproducing.com as soon as reasonably practicable after the Company electronically files such material with, or furnishes it to, the Commission. Additionally, the Company makes available free of charge on its Internet website:

- The Company's Code of Business Conduct and Ethics
- The Company's Corporate Governance Guidelines
- The Charters of the Company's Audit, Compensation and Nominating and Corporate Governance Committees

Any shareholder who so requests may obtain a printed copy of any of these documents from the Company. Changes in or waivers to the Company's Code of Business Conduct and Ethics required to be disclosed by rules of the Commission or the New York Stock Exchange will be posted on the Company's Internet website within five business days and maintained for at least twelve months.

ITEM 2. ***Properties.***

The information appearing in Item 1 of this Annual Report is incorporated herein by reference.

ITEM 3. ***Legal Proceedings.***

The Company is a party to various legal proceedings consisting of routine litigation incidental to its businesses, but believes that any potential liabilities resulting from these proceedings are adequately covered by insurance or are otherwise immaterial at this time. See "Business Government Regulation; Other Laws and Regulations."

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

No matters were submitted to a vote of the Company's security holders during the fourth quarter of the year ended December 31, 2003.

ITEM S-K 401(b). ***Executive Officers of Registrant.***

Officers of the Company are appointed annually by the Company's Board of Directors to serve for the ensuing year or until their successors have been elected or appointed. The officers of the Company that have been designated as "executive officers" for purposes of Item 401(b) of Regulation S-K and "officers" for purposes of Section 16 of the Exchange Act, their age as of December 31, 2003, and the year each was elected to his current position are as follows:

Executive Officer	Executive Office	Age	Year Elected
Paul G. Van Wagenen	Chairman, President and Chief Executive Officer	57	1991
Stephen R. Brunner	Executive Vice President Operations	45	2002
Stuart P. Burbach	Executive Vice President Exploration	51	1998
Jerry A. Cooper	Executive Vice President and Regional Manager Western United States	55	2002
John O. McCoy, Jr.	Executive Vice President and Chief Administrative Officer	52	2002
David R. Beathard	Senior Vice President Engineering	45	2002
Gerald A. Morton	Senior Vice President and Regional Manager Asia and Pacific and Corporate Secretary	45	2003
James P. Ulm, II	Senior Vice President and Chief Financial Officer	40	2002
Thomas E. Hart	Vice President and Chief Accounting Officer	60	1999
Michael J. Killelea	Vice President and General Counsel	41	2001

Mr. Van Wagenen, who joined the Company in 1979, has served in his current position since 1991. Prior to assuming their present positions with the Company, the business experience of each of the other executive officers for at least the last five years was as follows: Mr. Brunner, who joined the Company in 1994, served as Vice President Operations since 1997; Mr. Burbach served as Vice President and Offshore Division Manager since rejoining the Company in 1991; Mr. Cooper, who joined the Company in 1979, served as Senior Vice President and Western Division Manager since 1998 and prior thereto served as Vice President and Western Division Manager since 1990; Mr. McCoy, who joined the Company in 1978, served as Senior Vice President and Chief Administrative Officer of the Company since 1998 and prior thereto as Vice President and Chief Administrative Officer since 1989; Mr. Beathard, who joined the Company in 1982, served as Vice President Engineering since 1997; Mr. Morton, who joined the Company in 1993, served as Vice President and Regional Manager -Asia and

Pacific since 2002 and Vice President Law, Chief Regulatory Officer and Corporate Secretary since 2001, and prior thereto was Vice President Law and Corporate Secretary since 1997; Mr. Ulm served as Treasurer of Newfield Exploration Company from 1995 until joining the Company as its Vice President and Chief Financial Officer in 1999; Mr. Hart joined the Company in 1977 and served as Vice President and Controller since 1988; and Mr. Killelea was Chief Counsel of the Company since he joined the Company in 2000 and prior thereto served as Chief Counsel of CMS Oil and Gas Company for more than three years.

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PART II

ITEM 5. ***Market for the Registrant's Common Equity and Related Stockholder Matters.***

The following table shows the range of low and high sales prices of the Company's Common Stock (the "Common Stock") on the New York Stock Exchange composite tape where the Common Stock trades under the symbol PPP. The Common Stock is also listed on the Pacific Exchange under the same symbol.

	Low	High
2002		
1st Quarter	$ 23.00	$ 31.75
2nd Quarter	$ 29.44	$ 35.49
3rd Quarter	$ 25.44	$ 34.71
4th Quarter	$ 31.90	$ 39.28
2003		
1st Quarter	$ 34.29	$ 39.98
2nd Quarter	$ 38.68	$ 45.41
3rd Quarter	$ 40.30	$ 46.42
4th Quarter	$ 41.63	$ 49.50

As of February 13, 2004, there were 2,125 holders of record of the Company's Common Stock.

In 2002, the Company paid four quarterly dividends of $0.03 per share on its Common Stock. On January 21, 2003, the Company increased its dividend 67% and during 2003 the Company paid four quarterly dividends of $0.05 per share on its Common Stock. The declaration and payment of future dividends, and the amount of such dividends, will depend upon, among other things, the Company's future earnings and financial condition, liquidity and capital requirements, the general economic and regulatory climate and other factors deemed relevant by the Company's Board of Directors.

The Company's revolving credit facility with its banks under which the Company has borrowed funds, and the Indentures relating to the Company's $10^3/_8$% Senior Subordinated Notes due 2009 (the "2009 Notes") and $8^1/_4$% Senior Subordinated Notes due 2011 (the "2011 Notes") contain covenants that may restrict the ability of the Company to pay future dividends on the Company's Common Stock. The Company does not currently believe that any of these agreements will restrict the Company's ability to pay dividends on its Common Stock in the reasonably foreseeable future.

No equity securities of the Company not registered under the Securities Act of 1933 were sold by the Company during the year ended December 31, 2003.

During the year ended December 31, 2003, no equity securities of the Company registered pursuant to Section 12 of the Securities Exchange Act of 1934 were purchased by or on behalf of the Company or any "affiliated purchaser" of the Company, as defined in Rule 10b-18(a)(3) under the Securities Exchange Act.

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ITEM 6. ***Selected Financial Data.***

In the following table, the Company's financial, production and other data for 2003, 2002 and 2001 reflect the Company's acquisition of North Central from and on March 14, 2001. The selected financial data should be read in conjunction with "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations" and the audited consolidated financial statements and notes thereto included under "Item 8 Financial Statements and Supplementary Data."

	For the Year Ended December 31,				
	2003	2002	2001(a)	2000(a)	1999(a)
	(Expressed in thousands, except per share and production data)				
Financial Data					
Revenues:					
Crude oil and condensate	$ 651,334	$ 431,769	$ 261,226	$ 272,932	$ 109,803
Natural gas	475,834	294,206	322,390	190,401	111,152
Natural gas liquids	32,376	24,426	12,461	15,869	9,544
Oil and gas revenues	1,159,544	750,401	596,077	479,202	230,499
Other	2,452	4,453	14,040	18,789	44,617(d)
Total	$ 1,161,996	$ 754,854	$ 610,117	$ 497,991	$ 275,116
Income (loss) before cumulative effect of change in accounting principle	$ 295,107	$ 107,031	$ 87,954	$ 89,023	$ 22,134
Cumulative effect of change in accounting principle	(4,166)(b)			(1,768)(c)	
Net income (loss)	$ 290,941	$ 107,031	$ 87,954	$ 87,255	$ 22,134
Per share data:					
Income (loss) before cumulative effect of change in accounting principle					
Basic	$ 4.72	$ 1.85	$ 1.72	$ 2.20	$ 0.55
Diluted	$ 4.60	$ 1.77	$ 1.62	$ 1.99	$ 0.55
Cash dividends on common stock	$ 0.20	$ 0.12	$ 0.12	$ 0.12	$ 0.12
Price range of common stock:					
High	$ 49.50	$ 39.28	$ 34.50	$ 33.19	$ 23.44
Low	$ 34.29	$ 23.00	$ 20.45	$ 18.00	$ 8.94
Weighted average number of common shares outstanding	62,538	57,963	51,031	40,445	40,178
Long-term debt at year end	$ 487,261	$ 722,903	$ 792,561	$ 365,000	$ 375,000
Minority interest at year end	$	$	$ 145,086	$ 144,913	$ 144,751
Shareholders' equity at year end	$ 1,453,653	$ 1,077,784	$ 824,885	$ 358,271	$ 268,512
Total assets at year end	$ 2,762,036	$ 2,491,593	$ 2,423,979	$ 1,114,649	$ 948,193
Production (Sales) Data					
Net daily average production and weighted average price:					
Natural gas (Mcf per day)	297,000	279,000	237,800	164,600	141,600
Price (per Mcf)	$ 4.39	$ 2.89	$ 3.71	$ 3.16	$ 2.15
Crude oil-condensate (Bbl per day)	62,121	47,360	29,590	25,788	16,036
Price (per Bbl)	$ 29.10	$ 24.89	$ 23.99	$ 28.92	$ 18.76
Natural gas liquids (Bbl per day)	4,109	4,480	2,118	2,141	2,077

	For the Year Ended December 31,				
Price (per Bbl)	$ 21.59	$ 14.94	$ 16.12	$ 20.25	$ 12.59

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	For the Year Ended December 31,				
	2003	2002	2001	2000	1999
	(Expressed in thousands)				
Capital Expenditures (including interest capitalized)					
Oil and gas:					
Domestic Offshore					
Exploration	$ 28,100	$ 33,600	$ 18,000	$ 18,700	$ 12,600
Development	23,900	100,700	169,000	43,700	43,200
Purchase of reserves			87,700		
Onshore North America					
Exploration	26,200	14,500	38,300	19,700	9,800
Development	118,000	117,200	113,600	34,700	19,800
Purchase of reserves	177,700		1,027,200	8,400	19,500
International					
Exploration	20,900	3,100	11,500	9,400	3,500
Development	123,000	109,300	64,700	51,500	106,300
Purchase of reserves					
Total oil and gas	517,800	378,400	1,530,000	186,100	214,700
Other	2,500	3,300	4,800	700	2,200
Total	$ 520,300	$ 381,700	$ 1,534,800	$ 186,800	$ 216,900

(a) The Company's financial statements for 1999 - 2001 were audited by Arthur Andersen LLP, who have ceased operations.

(b) Effective January 1, 2003, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143 ("SFAS 143"), "Accounting for Asset Retirement Obligations". This new accounting standard required a change in the accounting for asset retirement obligations. See "Management's Discussion and Analysis of Financial Condition and Results of Operations, Application of Critical Accounting Policies and Management's Estimates, Future Development and Abandonment Costs" for further discussion of the provisions of SFAS 143.

(c) Crude oil and condensate from the Company's producing fields located in the Kingdom of Thailand are produced into storage vessels and are sold and recognized as revenue periodically as economic quantities are accumulated. Effective January 1, 2000, the Company adopted the provisions of the Securities and Exchange Commission's (the "SEC") Staff Accounting Bulletin No. 101, Revenue Recognition, and revised its long-standing historical practice of recording such product inventories at their net realizable value. The cumulative effect of this change in accounting principle through December 31, 1999 ($1,768,000, net of tax benefits of $1,768,000) was charged to earnings effective January 1, 2000.

(d) Primarily reflects the gain on sale of the Company's Lopeno field in the first quarter of 1999.

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

Statements in the following discussion may be forward-looking and involve risks and uncertainties. The Company's financial results are most directly affected by changing prices for its production. Changing prices can influence not only current results of operations but the determination of the Company's proved reserves and available sources of financing, including the determination of the borrowing base under its bank credit facility. The Company's results depend not only on hydrocarbon prices generally, but on its ability to market its production on favorable terms in the areas in which it is produced, including foreign areas such as Thailand where the Company's operations may be subject to local constraints on demand, currency restrictions, exchange rate fluctuations, the possibility of increases in taxes or other charges and non-renewal or other adverse action relating to concessions or contracts, and other political risks. On a

longer term basis, the Company's financial condition and results of operations are affected by its ability to replace reserves as they are produced through successful exploration, development and acquisition activities. The Company's results could also be adversely affected by adverse regulatory developments and operational risks associated with oil and gas operations. Some of the other risks and uncertainties that may affect the Company's results are mentioned in the discussion that follows.

On March 14, 2001, the merger of the Company and NORIC Corporation ("NORIC") was consummated. As a result of the merger, the Company acquired all of the outstanding capital stock of North Central Oil Corporation ("North Central"), an independent domestic oil and gas exploration and production company, which was the principal asset of NORIC. The merger was accounted for using the purchase method of accounting. Commencing March 14, 2001, the results of North Central's operations are consolidated with the Company's.

Executive Overview

The Company's objective is to cost effectively explore for, develop, acquire and produce oil and gas in select locations worldwide. In pursuit of that objective, the Company's goal for each year is to add more oil and gas reserves than it produces. 2003 marked the twelfth consecutive year of reserve replacement for the Company.

The Company pursues a balanced approach in core areas located in major oil and gas provinces in the United States and internationally. The Company follows a strict set of criteria when selecting areas of the world in which to explore. Areas selected are viewed as having proven oil and gas resources, having reasonable economic terms and possessing low political risk. Following these criteria, the Company operates internationally in several selected areas: Gulf of Thailand, Hungary, offshore New Zealand and in the Danish North Sea. The Company also seeks to maintain a balanced mixture of the gas/oil ratio of its reserves base.

Since January 2001, the Company has increased reserves and production by 81% and 108%, respectively. At the end of 2003, reserves topped 1,701 Bcfe and production for the year averaged more than 115,000 BOE per day, both exceeding previous Company records set in 2002. Oil and gas pricing and production volumes are important components of an exploration and development company's growth in net income and cash flow. In 2003, oil and gas pricing for the Company was strong, increasing 32% over 2002.

The Company made significant improvements to its balance sheet and financial leverage last year. Long-term debt (excluding debt discount) was $489 million at December 31, 2003, down from $725 million the previous year. Interest charges also were reduced from $57.5 million in 2002 to $46.4 million in 2003. The Company's debt to total capitalization ratio, an indicator of a company's financial strength, decreased to 25% from 40%. Cash and cash equivalents increased from $134 million to $179 million at year-end 2003. Company management believes being fiscally conservative is essential to position the Company for future growth.

Capital and exploration expenditures for 2003 were approximately $512 million. Exploration & development operations were allocated approximately $334 million, and approximately $178 million was spent on selective acquisitions in the Company's core areas of operations. The Company anticipates spending $415 million in 2004 (excluding property acquisitions), the largest exploration and development budget in the Company's history, and the Company will continue to pursue selective acquisitions.

The Company experienced strong drilling results during 2003. The Company drilled 248 wells during the year, with 232 wells successfully completed, a 94% success rate. During 2004, the Company anticipates drilling approximately 300 wells, another record number for the company.

2004 Production Outlook. A temporary shutdown of the Benchamas Field in the Gulf of Thailand to upgrade the Benchamas central processing platform, commenced in January 2004 and was completed in February 2004. Operations are currently underway to re-establish full production from all producing wells in the field. The shutdown is currently expected to reduce the Company's Gulf of Thailand crude oil and condensate and natural gas production for 2004 by approximately 2,500 barrels per day and 10 MMcf per day, respectively. This shutdown combined with normal production declines at the Company's Main Pass Blocks 61/62 Field, Mississippi Canyon Blocks 661/705 Field, and Ewing Banks Block 871 Field are currently expected to reduce the Company's overall equivalent hydrocarbon production by approximately 4-7% during 2004, compared to 2003, subject to changes in circumstances, acquisitions and many other factors.

Results of Operations

Oil and Gas Revenues

The Company's oil and gas revenues for 2003 were $1,159,544,000, an increase of approximately 55% from oil and gas revenues of $750,401,000 for 2002, which were an increase of approximately 26% from oil and gas revenues of $596,077,000 for 2001. The following table reflects an analysis of variances in the Company's oil and gas revenues (expressed in thousands) between years:

	2003 Compared to 2002	2002 Compared to 2001
Increase (decrease) in oil and gas revenues resulting from variances in:		
Natural gas		
Price	$ 152,879	$ (71,612)
Production	28,749	43,428
	181,628	(28,184)
Crude oil and condensate		
Price	72,984	9,866
Production	146,581	160,677
	219,565	170,543
Natural gas liquids ("NGL")	7,950	11,965
Increase in oil and gas revenues	$ 409,143	$ 154,324

The increase in the Company's oil and gas revenues in 2003, compared to 2002, is related to increases in both the average price that the Company received for its hydrocarbon production volumes and an increase in the Company's natural gas and crude oil and condensate production volumes. The increase in the Company's oil and gas revenues in 2002, compared to 2001, is related to increases in the Company's hydrocarbon production volumes which were only partially offset by a decrease in the average price that the Company received for natural gas production volumes. The increase in oil and gas revenues for 2003, compared to 2002 and 2001, was also the result of an increase in the average price that the Company received for its NGL production volumes from $16.14 and $14.94 in 2001 and 2002, respectively, to $21.59 in 2003.

	2003	2002	% Change 2003 to 2002	2001	% Change 2002 to 2001

	2003	2002	% Change 2003 to 2002	2001	% Change 2002 to 2001
Comparison of Increases (Decreases) in:					
Natural Gas					
Average prices					
North America(a)	**$ 5.17**	$ 3.15	**64%**	$ 4.25	**(26)%**
Kingdom of Thailand(b)	**$ 2.49**	$ 2.22	**12%**	$ 2.30	**(3)%**
Company-wide average price	**$ 4.39**	$ 2.89	**52%**	$ 3.71	**(22)%**
Average daily production volumes					
(MMcf per day):					
North America(a)	**210.4**	201.3	**5%**	172.8	**16%**
Kingdom of Thailand	**86.5**	77.8	**11%**	65.1	**20%**
Company-wide average daily production	**296.9**	279.1	**6%**	237.9	**17%**
Crude Oil and Condensate					
Average prices(c)					
North America	**$ 29.08**	$ 24.95	**17%**	$ 24.60	**1%**
Kingdom of Thailand	**$ 29.14**	$ 24.80	**18%**	$ 23.38	**6%**
Company-wide average price	**$ 29.10**	$ 24.89	**17%**	$ 23.99	**4%**
Average daily production volumes					
(Bbls per day):					
North America(c)	**40,173**	30,971	**30%**	14,804	**109%**
Kingdom of Thailand(d)	**21,948**	16,389	**34%**	14,786	**11%**
Company-wide average daily production	**62,121**	47,360	**31%**	29,590	**60%**
Total Liquid Hydrocarbons					
Company-wide average daily production (Bbls per day)(d)	**66,230**	51,840	**28%**	31,707	**63%**

(a) North American average prices and production reflect production from the United States (and Canada for 2001) and the impact of the Company's price hedging activity. Price hedging activity reduced the average price $0.17 during 2003 and added $0.04 and $0.23 to the average price of the Company's North American natural gas production during 2002 and 2001, respectively. The Company sold its operations in Canada effective August 31, 2001, as part of an asset rationalization process. Consequently, results for the 2002 and a portion of the 2001 comparative periods do not reflect any production from Canada.

(b) The Company is paid for its natural gas production in the Kingdom of Thailand in Thai Baht. The average prices are presented in U.S. dollars based on the revenue recorded in the Company's financial records.

(c) North American average prices and production reflect production from the United States (and Canada for 2001). The Company sold its operations in Canada effective August 31, 2001, as part of an asset rationalization process. Consequently, results for the 2003, 2002 and a portion of the 2001 comparative periods do not reflect any production from Canada. Average prices are computed on production that is actually sold during the period and include the impact of the Company's price hedging activity. Price hedging activity reduced the average price of the Company's North American crude oil and condensate production $0.69 during 2003 and added $0.08 to the average price during 2002. For North American average prices, sales volumes equate to actual production. However, in the Gulf of Thailand, crude oil and condensate sold may be more or less than actual production. See footnote (d).

(d) Oil and condensate production in the Gulf of Thailand is produced and stored on the FPSO and FSO pending sale and is sold in tanker loads that typically average between 300,000 and 750,000 barrels per sale. Therefore, oil and condensate sales volumes for a given period in the Gulf of Thailand may not equate to actual production. In accordance with generally accepted accounting principles, reported revenues are based on sales volumes. However, the Company believes that actual production volumes also provide a meaningful measure of the Company's operating results. The Company produced 293,000 more than it sold in 2003, 58,000 barrels less than it sold in 2002 and 90,000 barrels less than it sold in 2001.

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Natural Gas

Thailand Prices. The Company has a long-term Gas Sales Agreement for its Kingdom of Thailand natural gas production. This agreement covered approximately 29% of the Company' 2003 natural gas production. The price that the Company receives under its Gas Sales Agreement with the Petroleum Authority of Thailand ("PTT") is based upon a formula that takes into account a number of factors including, among other items, changes in the Thai/U.S. exchange rate and fuel oil prices in Singapore. The contract price is also subject to adjustments for quality. Effective October 2001, an amendment to the Gas Sales Agreement was negotiated with PTT in which PTT agreed to purchase supplemental gas volumes (currently up to 85 MMcf per day) over and above the base contractual amount (currently 145 MMcf per day). These supplemental gas volumes over and above the base contractual amounts are sold to PTT at a price equal to 88% of the then-current price calculated under the Gas Sales Agreement for the base contractual volumes. In 2003, the Gas Sales Agreement was further amended to extend the period during which supplemental gas volumes would be provided to PTT through December 31, 2007. The price for the supplemental gas volumes was not changed and remains 88% of the then-current price calculated under the Gas Sales Agreement as previously described. See "Business International Operations; Contractual Terms Governing the Thailand Concession and Related Production."

Production. The increase in the Company's natural gas production during 2003, compared to 2002, was primarily related to increased production from the continuing success of the Company's exploration program at its Los Mogotes Field in South Texas, combined with the Company's continued development of its Gulf of Thailand concession and, to a lesser extent, an increase in the production capacity of the Lost Cabin Gas Plant located on the Company's Madden Field in Wyoming. These production gains were partially offset by natural production declines at other properties. The increase in the Company's natural gas production during 2002, compared to 2001, was primarily related to production from properties acquired in the North Central acquisition, successful development programs on the Company's Gulf of Mexico properties, including its Mississippi Canyon Blocks 661/705 Field, and increased Thailand production sold under the amendment to the Gas Sales Agreement, partially offset by natural production declines at other properties and weather-related shutdowns in the Gulf of Mexico.

Crude Oil and Condensate

Thailand Prices. Prices that the Company receives for its crude oil and condensate production from Thailand are based on world benchmark prices, typically as a differential to Malaysian TAPIS crude, and are denominated in U.S. dollars. As discussed further under "Costs and Expenses, Lease Operating Expenses," the Company records all crude oil held in the FPSO and the FSO at the end of an accounting period as inventory held at cost. When such crude oil is sold, usually during the following month, the cost of the crude oil and the sales revenue are recognized in the income statement.

Production. The increase in the Company's crude oil and condensate production during 2003, compared to 2002, resulted primarily from the continued success of development programs at the Company's Main Pass Blocks 61/62 Field in the Gulf of Mexico and its Gulf of Thailand concession, partially offset by natural production declines at certain other properties. The increase in the Company's crude oil and condensate production during 2002, compared to 2001, resulted primarily from the success of the Company's development program in the Benchamas Field in the Kingdom of Thailand, the commencement of production from the Company's Main Pass Blocks 61/62 Field, its Mississippi Canyon Blocks 661/705 Field and its Ewing Bank Block 871 Field and, to a lesser extent, increased crude oil and condensate production in the Kingdom of Thailand associated with the increased natural gas production permitted by the amendment to the gas sales contract. These increases were partially offset by natural production declines at certain other properties and weather-related shut downs in the Gulf of Mexico.

In accordance with generally accepted accounting principles, the Company records its oil production at the time of sale, rather than when produced. At the end of each quarter, the crude oil and condensate

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stored on board the FSO and FPSO pending sale is accounted for as inventory at cost. Reported revenues are based on sales volumes. When a tanker load of oil is sold in Thailand, the entire amount is accounted for as production sold, regardless of when it was produced. As of December 31, 2003, the Company had approximately 495,000 net barrels stored on board the FPSO and FSO.

NGL Production. The Company's oil and gas revenues, and its total liquid hydrocarbon production, reflect the production and sale by the Company of NGL, which are liquid products that are extracted from natural gas production. The increase in NGL revenues for 2003, compared with 2002, related to an increase in the average price that the Company received for its NGL production to $21.59 in 2003 from $14.94 in 2002, partially offset by a slight decline in NGL production volumes. The increase in NGL revenues from 2002, compared to 2001, primarily related to NGL removed from the Company's Mississippi Canyon Blocks 661/705 Field gas production. This increase was partially offset by a decline in the average price that the Company received for its NGL production during the comparative periods, from $16.12 in 2001 to $14.94 in 2002.

Costs and Expenses

	2003	2002	% Change 2003 to 2002	2001	% Change 2002 to 2001
Comparison of Increases (Decreases) in:					
Lease Operating Expenses					
North America	**$ 81,731,000**	$ 74,416,000	**10%**	$ 55,700,000	**34%**
Kingdom of Thailand	**$ 41,367,000**	$ 38,247,000	**8%**	$ 36,993,000	**3%**
Total Lease Operating Expenses	**$ 123,098,000**	$ 112,663,000	**9%**	$ 92,693,000	**22%**
General and Administrative Expenses	**$ 61,291,000**	$ 49,490,000	**24%**	$ 39,162,000	**26%**
Exploration Expenses	**$ 7,547,000**	$ 4,783,000	**58%**	$ 23,373,000	**(80)%**
Dry Hole and Impairment Expenses	**$ 35,102,000**	$ 26,999,000	**30%**	$ 26,945,000	**0%**
Depreciation, Depletion and Amortization (DD&A) Expenses	**$ 325,820,000**	$ 287,809,000	**13%**	$ 206,609,000	**39%**
DD&A rate	**$ 1.29**	$ 1.33	**(3)%**	$ 1.32	**1%**
Mcfe sold	**253,422,703**	215,728,000	**17%**	156,780,000	**38%**
Production and Other Taxes	**$ 35,485,000**	$ 20,058,000	**77%**	$ 22,007,000	**(9)%**
Transportation and Other	**$ 25,924,000**	$ 12,879,000	**101%**	$ 19,447,000	**(34)%**
Interest					
Charges	**$ (46,360,000)**	$ (57,450,000)	**(19)%**	$ (56,259,000)	**2%**
Capitalized Interest Expense	**$ 16,531,000**	$ 24,033,000	**(31)%**	$ 33,242,000	**(28)%**
Loss on debt extinguishment	**$ (5,893,000)**	$	**N/M**	$	**N/M**
Minority Interest Dividends and Costs	**$**	$ (4,140,000)	**N/M**	$ (9,999,000)	**(59)%**
Income Tax Expense	**$ (220,122,000)**	$ (97,780,000)	**125%**	$ (61,613,000)	**59%**

Lease Operating Expenses

The increase in North American lease operating expenses for 2003, compared to 2002, is due to higher production from the Company's onshore properties and additional Gulf of Mexico platforms added during 2002 and the resulting increase in operating expenses as additional wells were subsequently brought on

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production and, to a lesser extent, increased expenses at the Lost Cabin gas plant in the Madden Unit, which was expanded in late 2002. The increase in North American lease operating expenses for 2002, compared to 2001, is related to higher production from the Company's Gulf of Mexico properties, and to a lesser extent, increased maintenance costs during 2002. As a result of the increased production from its Gulf of Mexico properties, the Company also incurred increased rental expenses for compressors and other equipment during 2002. In addition to the above factors, the increased lease operating expenses associated with properties acquired in the acquisition of North Central (completed on March 14, 2001) also impacted the comparison of 2002 to 2001.

The increase in lease operating expenses in the Kingdom of Thailand for 2003, compared to 2002, primarily related to costs associated with operating the five additional platforms which were added to the Gulf of Thailand primarily during the second half of 2002 and the resulting increase in operating expenses as additional wells were subsequently brought on production. The Company added three new platforms during 2003 and expects to add five new platforms in 2004. The increase in lease operating expenses in the Kingdom of Thailand for 2002, compared to 2001, primarily related to an increase in insurance expenses related to the construction of platforms and processing facilities for the Benchamas field. In accordance with generally accepted accounting principles, the portion of lifting costs that is attributable to crude oil and condensate stored on the FPSO and FSO is treated as an inventoried cost until that crude oil and condensate is sold. At the time the crude oil and condensate is sold, those inventoried lifting costs are recognized as lease operating expenses. Variances in production, sales and operating costs will result in variances in the amount of lease operating expense that is currently recognized as expense and the amount recorded as product inventory to be recognized in subsequent periods. A substantial portion of the Company's lease operating expenses in the Kingdom of Thailand relates to the lease payments made in connection with the bareboat charter of the FPSO for the Tantawan field and the FSO for the Benchamas field. Collectively, these lease payments accounted for approximately $14,500,000 (net to the Company's interest) of the Company's Thailand lease operating expenses for 2003, 2002 and 2001. The Company currently expects these lease payments to remain relatively constant at approximately $14,500,000 (net to the Company's interest) for the next three years. See "Liquidity and Capital Resources; Capital Requirements; Other Material Long-Term Commitments."

Notwithstanding the overall increase in lease operating expenses, on a per unit of production basis, the Company's total lease operating expenses have continued to decrease from an average of $0.59 per Mcfe for 2001 and $0.52 per Mcfe for 2002 to $0.49 per Mcfe for 2003.

General and Administrative Expenses

The increase in general and administrative expenses for 2003, compared with 2002, primarily related to higher benefit expenses, increases in professional fees, costs related to the start of operations in the Company's Budapest office, increased insurance costs and expenses related to the Company's decision, effective January 1, 2003, to expense stock-based compensation. The increase in general and administrative expenses for 2002, compared with 2001, primarily related to increased expenses associated with the Company's acquisition of North Central and its employees, as well as other increases in the size of the Company's work force, normal increases in compensation and concomitant benefit expense and, to a lesser extent, increases in map purchases, office rent, insurance costs and audit fees. On a per unit of production basis, the Company's general and administrative expenses were $0.24 per Mcfe in 2003, $0.23 per Mcfe in 2002 and $0.25 per Mcfe in 2001.

Exploration Expenses

Exploration expenses consist primarily of rental payments required under oil and gas leases to hold non-producing properties ("delay rentals") and exploratory geological and geophysical costs that are expensed as incurred. The increase in exploration expenses for 2003, compared to 2002, resulted primarily from increased 3-D seismic acquisition activities in the Gulf of Mexico and seismic operations in the

Company's Western division. The decrease in exploration expenses for 2002, compared to 2001, resulted primarily from a decrease in 3-D seismic acquisition activities during 2002. The 2001 expense includes the cost of conducting 3-D surveys in Hungary, the cost of acquiring substantial new speculative 3-D data sets in the Gulf of Mexico and seismic operations in Canada. The 2001 expense also includes the cost of transferring certain seismic licenses in connection with the North Central acquisition. There were no expenses comparable to these incurred in 2002.

Dry Hole and Impairment Expenses

Dry hole and impairment expenses relate to costs of unsuccessful exploratory wells drilled and impairment of oil and gas properties. During 2003 the Company drilled 6 gross unsuccessful exploratory wells (4.46 net to the Company's interest), in 2002 the Company drilled 6 unsuccessful exploratory wells (5.17 net to the Company's interest) and in 2001 the Company drilled 6 unsuccessful exploratory wells (3.06 net to the Company's interest). The Company has had overall drilling success rates of 94% in 2003, 92% in 2002 and 93% in 2001. The Company had approximately $9,511,000 of exploratory wells in progress or temporarily abandoned pending evaluation, located primarily in Hungary, at December 31, 2003.

Generally accepted accounting principles require that if the expected future cash flow of the Company's reserves on a property fall below the cost that is recorded on the Company's books, these costs must be impaired and written down to the property's fair value. Depending on market conditions, including the prices for oil and natural gas, and the results of operations, a similar test may be conducted at any time to determine whether impairments are appropriate. Depending on the results of this test, an impairment could be required on some of the Company's proved properties and this impairment could have a material negative non-cash impact on the Company's earnings and balance sheet. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. As a result of these reviews, the Company recognized impairments to oil and gas properties of approximately $10,542,000 during 2003, approximately $6,191,000 during 2002 and $9,991,000 during 2001.

Depreciation, Depletion and Amortization Expenses

The Company's provision for DD&A expense is based on its capitalized costs and is determined on a cost center by cost center basis using the units of production method. The Company generally creates cost centers on a field-by-field basis for oil and gas activities in the Gulf of Mexico and the Gulf of Thailand. Generally, the Company establishes cost centers on the basis of an oil or gas trend or play for its onshore oil and gas activities.

The increase in the Company's DD&A expense for 2003, compared to 2002, resulted primarily from an increase in the Company's natural gas and liquid hydrocarbon production, partially offset by a decrease in the Company's composite DD&A rate. The decrease in the composite DD&A rate for all of the Company's producing fields for 2003, compared to 2002, resulted primarily from an increased percentage of the Company's production coming from fields that have DD&A rates lower than the Company's recent historical composite rate (principally certain Gulf of Mexico properties and the Benchamas Field) and a corresponding decrease in the percentage of the Company's production coming from fields that have DD&A rates higher than the Company's recent historical composite DD&A rate.

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The increase in the Company's DD&A expense for 2002, compared to 2001, resulted primarily from an increase in the Company's natural gas and liquid hydrocarbon production and, to a lesser extent, an increase in the Company's composite DD&A rate. The increase in the composite DD&A rate for all of the Company's producing fields for 2002, compared to 2001, resulted primarily from having a full year's production from fields acquired in the North Central acquisition that, because they were valued at fair market value in connection with the acquisition, contribute a DD&A rate higher than the Company's historic average. The increase was partially offset by an increased percentage of the Company's production coming from certain of the Company's fields that have DD&A rates lower than the Company's recent historical composite rate (principally the Benchamas Field and certain Gulf of Mexico properties) and a corresponding decrease in the percentage of the Company's production coming from fields that have DD&A rates higher than the Company's recent historical composite DD&A rate.

Production and Other Taxes

The increase in production and other taxes for 2003, compared to 2002, relates to the recognition during 2003 of $11,750,000 of the Special Remunitory Benefit ("SRB") obligation incurred on the Company's Kingdom of Thailand concession. No comparable SRB expenses were incurred in 2002 or 2001. SRB is a payment to the Thai government required by the Company's concession agreement after certain specified revenue, expenditure and drilling criteria have been achieved. It is currently anticipated that the Company will continue to pay SRB for the foreseeable future. The amount of SRB to be incurred in 2004 is not currently determinable, as it will be computed using a complex formula that includes various factors such as revenues, expenditures and meters drilled on the Thailand concession during the year. See "Business International Operations; Contractual Terms Governing the Thailand Concession and Related Production." The increase is also related to increased severance taxes due to higher domestic onshore production volumes and prices. The decrease in production and other taxes for 2002, compared to 2001, primarily relates to decreased severance taxes due to lower prices received for the Company's domestic onshore production.

Transportation and Other

Transportation and other expense includes the Company's cost to move its products to market (transportation costs), accretion expense related to Company asset retirement obligation under a new accounting pronouncement adopted on January 1, 2003, natural gas purchase costs, pipeline operating costs, tubular inventory valuation write-offs and allowances, and various other operating expenses, none of which represents more than 5% of this expense category. The increase in transportation and other expense for 2003, compared to 2002, relates primarily to the inclusion of $4,972,000 of expense related to the accretion of the Company's asset retirement obligation and a $2,407,000 write down of the cost of the Company's tubular inventory stock, for which no comparable expenses were incurred in 2002. The Company incurred transportation expense of $12,980,000 in 2003 and $10,140,000 in 2002. The increase in transportation costs in 2003, compared to 2002, is due to the Company's higher hydrocarbon production volumes discussed above.

The decrease in transportation and other expense for 2002, compared to 2001, relates primarily to a decrease in the Company's pipeline operating costs and a reduction in the volume of natural gas purchased by the Company. During 2001, primarily all of the natural gas purchased and resold by the Company was transported on Pogo Onshore Pipeline Company's Saginaw pipeline, which was sold during the fourth quarter of 2001 as part of the Company's ongoing asset rationalization process. No material pipeline operating expenses were incurred by the Company subsequent to this sale. During 2002, substantially all of the natural gas purchased by the Company was the result of purchases of natural gas volumes required to replace the reduction in heating content of the gas stream after the extraction of NGLs. These purchases were made to bring the gas stream to pipeline quality standards. During 2003 and 2001, the Company used its own natural gas production to replenish this extracted gas and therefore was not required to purchase

natural gas from outside sources. The Company incurred transportation expense of $10,140,000 in 2002 and $3,457,000 in 2001. The increase in transportation costs in 2002, compared to 2001, is due to the commencement of production on certain of the Company's more significant Gulf of Mexico properties, primarily the Company's Mississippi Canyon Block 661/705 as discussed above.

Interest

Interest Charges. The decrease in the Company's interest charges for 2003, compared to 2002, resulted primarily from a decrease of approximately $236 million in the Company's outstanding debt during the year, partially offset by an increase in the average interest rate on the debt that remained outstanding. The increase in the Company's interest charges for 2002, compared to 2001, resulted primarily from an increase in the average amount of the Company's outstanding debt (largely related to the acquisition of North Central in March 2001), partially offset by a decline in the average interest rate on the outstanding debt.

Capitalized Interest. Interest costs related to financing major oil and gas projects in progress are required to be capitalized until the projects are substantially complete and ready for their intended use if projects are evaluated as successful. The decrease in capitalized interest for 2003, compared to 2002, and for 2002, compared to 2001, resulted primarily from a decrease in the amount of capital expenditures subject to interest capitalization during 2003 (approximately $192,000,000), compared to 2002 (approximately $346,000,000), and a decrease in the amount of capital expenditures subject to interest capitalization during 2002 compared to 2001 (approximately $365,000,000). These decreases were also impacted by changes in the weighted average rate on borrowings incurred by the Company (discussed above under "Results of Operations Interest Charges") and applied to such capital expenditures to arrive at the total amount of capitalized interest. A substantial percentage of the Company's capitalized interest related to unevaluated properties acquired in the North Central acquisition and capital expenditures for the development of the Benchamas Field in the Gulf of Thailand, as well as several development projects in the Gulf of Mexico. Several of these projects were placed in service during 2003.

Loss on Debt Extinguishment

The loss on debt extinguishment for 2003 is related to redemption premiums paid and unamortized debt issuance costs which were expensed due to the redemption of the 2006 Notes and 2007 Notes. No comparable costs were incurred in either 2002 or 2001.

Minority Interest Dividends and Costs Associated with Mandatorily Redeemable Convertible Preferred Securities of a Subsidiary Trust

Pogo Trust I, a business trust in which the Company owned all of the issued common securities, issued $150,000,000 of Trust Preferred Securities on June 2, 1999. Pogo Trust I called the Trust Preferred Securities for redemption on June 3, 2002. Prior to their redemption, holders of 2,997,196 of the 3,000,000 outstanding Trust Preferred Securities converted their Trust Preferred Securities, representing over $149,850,000 face value of Trust Preferred Securities, into 6,309,972 shares of the Company's common stock. In connection with the redemption, Pogo Trust I paid a total of $147,000 to former holders of the Trust Preferred Securities. Subsequent to June 3, 2002, there were no Trust Preferred Securities outstanding. The amounts recorded under Minority Interest Dividends and Costs Associated with Preferred Securities of a Subsidiary Trust principally reflect cumulative dividends and, to a lesser extent, the amortization of issuance expenses related to the offering and sale of the Trust Preferred Securities.

Income Tax Expense

Changes in the Company's income tax expense are a function of the Company's consolidated effective tax rate and its pre-tax income. The increase in the Company's tax expense for 2003, compared to 2002,

resulted primarily from increased pre-tax income derived from both the Company's U.S. and Thailand operations in 2003, partially offset by a decrease in the Company's effective tax rate during the comparative periods. The increase in the Company's tax expense for 2002, compared to 2001, resulted primarily from an increase in the Company's effective tax rate during the comparative periods and from increased pre-tax income during 2002. The Company's consolidated effective tax rate for 2003, 2002 and 2001 was 43%, 48% and 41%, respectively. The lower effective tax rates during the 2003 and 2001 periods, compared to 2002, are the result of higher pre-tax income derived from the Company's North

American operations during the comparative periods, relative to its pre-tax income from its Thailand operations which are taxed at a rate higher than the U.S. statutory rate. Management currently expects that foreign income taxes will constitute a substantial portion of its overall tax burden for the foreseeable future.

Cumulative Effect of Change in Accounting Principle

The Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," ("SFAS 143"), as of January 1, 2003. SFAS 143 requires the Company to record the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred. Upon adoption of SFAS 143, the Company was required to recognize a liability for the present value of all legal obligations associated with the retirement of tangible long-lived assets and an asset retirement cost was capitalized as part of the carrying value of the associated asset. Upon initial application of SFAS 143, the Company recorded an after-tax charge to recognize the cumulative effect of a change in accounting principle of $4,166,000. This charge was required in order to recognize a liability for any existing AROs adjusted for cumulative accretion, and also to increase the carrying amount of the associated long-lived asset and its accumulated depreciation.

Liquidity and Capital Resources

The Company's primary needs for cash are for exploration, development, acquisition and production of oil and gas properties, repayment of principal and interest on outstanding debt and payment of income taxes. The Company funds its exploration and development activities primarily through internally generated cash flows and budgets capital expenditures based on projected cash flows. The Company adjusts capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition results, and cash flow. The Company has historically utilized net cash provided by operating activities, available cash, debt, and equity as capital resources to obtain necessary funding for all other cash needs.

The Company's cash flow provided by operating activities for 2003 was $744,559,000. This compares to cash flow from operating activities of $466,479,000 in 2002 and $368,076,000 in 2001. The resulting increases are attributable to the reasons described under "Results of Operations" above. Cash flow from operating activities in 2003 was more than adequate to fund $524,698,000 in cash expenditures for capital and exploration projects for the year. The Company also repaid approximately $197,566,000 of cash (net of borrowings) to settle debt obligations (including the redemptions discussed below) and paid $12,520,000 of dividends on the Company's common stock during 2003. As of December 31, 2003, the Company had cash and cash equivalents of $178,754,000 (including $170,092,000 in international subsidiaries which the Company intends to reinvest in its foreign operations) and long-term debt obligations of $489,000,000 (excluding debt discount of $1,739,000) with no repayment obligations until 2006. On July 7, 2003, the Company satisfied all $115,000,000 of its outstanding $5^1/_2$% Convertible Subordinated Notes due 2006 for 1,008,299 shares of common stock and $73,661,000 in cash. On August 6, 2003, the Company redeemed all $100,000,000 of its $8^3/_4$% Senior Subordinated Notes due 2007 for $102,917,000 in cash. The Company, at its option, may redeem the $10^3/_8$% Senior Subordinated Notes due 2009, in whole or in part, at any time on or after February 15, 2004, at a redemption price of 105.188% of their principal value. The Company may elect to repurchase the 2009 Notes through market transactions, privately negotiated transactions or otherwise, depending on market conditions, liquidity requirements, contractual restrictions and other factors.

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Effective October 30, 2003, the Company's lenders redetermined the borrowing base under its Credit Agreement at $800,000,000. The available borrowing capacity under the Credit Agreement is currently $515,000,000. As of February 18, 2003, the Company had an outstanding balance of $122,000,000 under its Credit Agreement See "Capital Structure Credit Facility".

Future Capital and Other Expenditure Requirements

The Company's capital and exploration budget for 2004, which does not include any amounts that may be expended for acquisitions or any interest which may be capitalized resulting from projects in progress, was established by the Company's Board of Directors at $415,000,000. The Company has included 300 gross wells in its 2004 capital and exploration budget, including wells to be drilled in the United States, the Kingdom of Thailand, Hungary and Denmark. The Company currently anticipates that its available cash and cash investments, cash provided by operating activities and funds available under its Credit Agreement will be sufficient to fund the Company's ongoing operating, interest and general and administrative expenses, its authorized capital budget, and dividend payments at current levels for the foreseeable future. The declaration and amount of future dividends on the Company's common stock will depend upon, among other things, the Company's future earnings and financial condition, liquidity and capital requirements, its ability to pay dividends and other payments under covenants contained in its debt instruments, the general economic and regulatory climate and other factors deemed relevant by the Company's Board of Directors.

Other Material Long-Term Commitments

Contractual Obligations. The Company's material contractual obligations include long-term debt, operating leases, and other contracts. Material 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 and other factors. See "Item 3. Quantitative and Qualitative Disclosure about Market Risk."

A summary of the Company's known contractual obligations as of December 31, 2003 are set forth on the following table**:**

	Payments due by period (in millions)				
	Total	**Less than 1 Year**	**1 - 3 Years**	**3 - 5 Years**	**More than 5 Years**
Long Term Debt	$ 489.0	$ 0.0	$ 139.0	$ 0.0	$ 350.0
Operating Leases(a)	$ 144.3	$ 22.3	$ 43.9	$ 34.1	$ 44.0
Purchase Obligations(b)	$ 64.9	$ 19.0	$ 25.9	$ 8.6	$ 11.4
Asset Retirement Obligations (c)	$ 236.4	$ 1.7	$ 7.5	$ 14.7	$ 212.5
Total	$ 934.6	$ 43.0	$ 216.3	$ 57.4	$ 617.9

(a) Operating leases principally include the lease of the FPSO and FSO in Thailand, the Company's office lease commitments and various other equipment rentals, including gas compressors. Where rented equipment such as compressors is considered essential to the operation of the lease, the Company has assumed that such equipment will be leased for the estimated productive life of the reserves, even if the contract terminates prior to such date. See Note 5 to the Consolidated Financial Statements.

(b) This represents: i) the Company's share of the contractual commitments for two rigs drilling in the Gulf of Thailand and one rig drilling in Hungary. No other drilling rigs working for the Company are currently under contracts that have a term greater than six months or which cannot be terminated at the end of the well that is currently being drilled. Due to their short-term nature and the indeterminate nature of the drilling time/liabilities remaining on rigs drilling on a well-by-well basis, such obligations have not been included in this table; and ii) firm transportation agreements representing "ship-or-pay" arrangements whereby the Company has committed to ship certain volumes of gas for a fixed transportation fee (principally from the Madden Field in Wyoming). The Company entered into these arrangements to ensure its access to gas markets and currently expects to produce sufficient volumes to satisfy substantially all of its firm transportation obligations.

(c) This represents the Company's estimate of future asset retirement obligations on an undiscounted basis. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See Note 11 to the Consolidated Financial Statements.

Commitments under Joint Operating Agreements. The oil and gas industry operates in many instances through joint ventures under joint operating agreements, and the Company's operations are no exception. Typically, the operator under a joint operating agreement enters into contracts, such as drilling contracts, for the benefit of all joint venture partners. Through the joint operating agreement, the non-operators reimburse, and in some cases advance, the funds necessary to meet the contractual obligations entered into by the operator. These obligations are typically shared on a "working interest" basis. The joint operating agreement provides remedies to the operator in the event that the non-operator does not satisfy its share of the contractual obligations. Occasionally, the operator is permitted by the joint operating agreement to enter into lease obligations and other contractual commitments that are then passed on to the non-operating joint interest owners as lease operating expenses, frequently without any identification as to the long-term nature of any commitments underlying such expenses. The contractual obligations set forth above represent the Company's working interest share of the contractual commitments that it has entered into as operator and, to the extent that it is aware, the contractual commitments entered into by the operator of projects that the Company does not operate.

Surety Bonds. In the ordinary course of the Company's business and operations, it is required to post surety bonds from time to time with third parties, including governmental agencies, primarily to cover self insurance, site restoration, equipment dismantlement, plugging and abandonment obligations. As of December 31, 2003, the Company had obtained surety bonds from a number of insurance and bonding institutions covering certain operations in the United States in the aggregate amount of approximately $10,000,000 that are not included in the prior table. In connection with their administration of offshore leases in the Gulf of Mexico, the MMS annually evaluates each lessee's plugging and abandonment liabilities. The MMS reviews this information and applies certain financial tests including, but not limited to, current asset and net worth tests. The MMS determines whether each lessee is financially capable of paying the estimated costs of such plugging and abandonment liabilities. The Company must annually provide the MMS with financial information. If the Company does not satisfy the MMS requirements, it could be required to post supplemental bonds. In the past, the Company has not been required to post supplemental bonds; however, there can be no assurance that the Company will satisfy the financial tests and remain on the list of MMS lessees exempt from the supplemental bonding requirements. The Company cannot predict or quantify the amount of any such supplemental bonds or the annual premiums related thereto and therefore has not included them in the prior table, but the amount could be substantial.

Guarantees and Letters of Credit. The Company has also issued performance guarantees related to the operations of its subsidiaries in Thailand, Hungary and Denmark. If its subsidiaries do not fulfill their contractual obligations or legal obligations under the relevant local laws, the Company could be obligated to make payments to satisfy the subsidiaries' obligations. Most of these obligations relate to plugging, abandonment, site restoration and compliance with environmental laws. The Company also has guaranteed performance of its subsidiaries' obligations under the FPSO lease. However, the Company's guarantee of these obligations has not been so included. Currently, there are no material letters of credit that have been issued on the Company's behalf.

Credit Facility and Borrowing Base Determination

Credit Facility. The Company has a revolving credit facility (the "Credit Facility") that provides for a $515,000,000 revolving loan facility terminating on March 7, 2006. The amount that may be borrowed under the Credit Facility may not exceed a borrowing base that is determined no less than semi-annually and is calculated based upon substantially all of the Company's proved oil and gas properties. The borrowing base is currently set at $800,000,000. The next redetermination of the borrowing base is expected to occur by May 1, 2004. The borrowing base is determined by the lenders based on their own proprietary credit criteria, which appear to be strongly correlated to the quantity of the Company's proven oil and gas reserves and the lenders' expectations as to the future revenues that the Company can expect to

receive from the sale of these oil and gas reserves. A significant decline in the prices that the Company is expected to receive for its future oil and gas production could have a material negative impact on the borrowing base under the Credit Facility which, in turn, could have a material negative impact on the Company's liquidity. If at a redetermination of the borrowing base, the lenders reduce the borrowing base below the amount then outstanding under the Credit Agreement and other senior debt arrangements, the Company must repay the excess to the lenders in no more than five substantially equal monthly installments, commencing not later than 90 days after the Company is notified of the new borrowing base. The Credit Facility also permits short-term "swing line" loans and the issuance of up to $50,000,000 in letters of credit as a part of the facility. Borrowings under the Credit Facility bear interest, at the Company's option, at a base (prime) rate plus a variable margin (currently none) or LIBOR plus a variable margin (currently 1.125%). The margin varies as a function of the percentage of the borrowing base being utilized and, with respect to the LIBOR rate loans, the Company's credit rating. A commitment fee on the unborrowed amount that is currently available under the Credit Facility is also charged based upon the percentage of the borrowing base that is being utilized. As of February 18, 2004, there was $122,000,000 outstanding under the Credit Facility.

Application of Critical Accounting Policies and Management's Estimates

The discussion and analysis of the Company's financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in Note 1 to our consolidated financial statements included in this Form 10-K. We have identified below policies that are of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. We analyze our estimates, including those related to oil and gas revenues, bad debts, oil and gas properties, marketable securities, income taxes, derivatives, contingencies and litigation, on a periodic basis and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of the Company's financial statements:

Successful Efforts Method Of Accounting

The Company accounts for its oil and gas exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and gas leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but such costs are charged to expense if and when the well is determined not to have found reserves in commercial quantities. In most cases, a gain or loss is recognized for sales of producing properties.

The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. Wells may be completed that are assumed to be productive and actually deliver oil and gas in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. On occasion, wells are drilled which have targeted geologic structures that are both developmental and exploratory in nature, and in such instances an allocation of

costs is required to properly account for the results. Delineation seismic costs incurred to select development locations within a productive oil and gas field are typically treated as development costs and capitalized, but often these seismic programs extend beyond the proved reserve areas and therefore management must estimate the portion of seismic costs to expense as exploratory. The evaluation of oil and gas leasehold acquisition costs requires management's judgment to estimate the fair value of exploratory costs related to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

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

Reserve Estimates

The Company's estimates of oil and gas reserves are, by necessity, projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulations by governmental agencies, and assumptions governing future oil and gas prices, future operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves are later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of expected oil and gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company's oil and gas properties and/or the rate of depletion of such oil and gas properties. Actual production, revenues and expenditures with respect to the Company's reserves will likely vary from estimates, and such variances may be material.

Impairment Of Oil and Gas Properties

The Company reviews its proved oil and gas properties for impairment on an annual basis or whenever events and circumstances indicate a potential decline in the recoverability of their carrying value. The Company estimates the expected future cash flows from its proved oil and gas properties and compares these future cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and gas properties to its fair value in the current period. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. The Company has recognized significant impairment expense due to poor reservoir performance at one of its Gulf of Mexico properties in the first quarter of 2001, and has recognized other less significant impairment expenses related to other properties in subsequent periods. Given the complexities associated with oil and gas reserve estimates and the history of price volatility in the oil and gas markets, events may arise that will require the Company to record an impairment of its oil and gas properties and there can be no assurance that such impairments will not be required in the future.

Fair Values Of Derivative Instruments

The estimated fair values of the Company's derivative instruments are recorded on the Company's consolidated balance sheet. Historically, substantially all of the Company's derivative instruments have represented cash flow hedges of the price of future oil and natural gas production. Therefore, while fair values of such hedging instruments must be estimated at the end of each reporting period, the related changes in such fair values are not included in the Company's consolidated results of operations, to the extent they are expected to offset the future cash flows from oil and natural gas production. Instead, the changes in fair value of hedging instruments are recorded directly to shareholders' equity until the hedged oil or natural gas quantities are produced.

The estimation of fair values for the Company's hedging derivatives requires substantial judgment. The Company estimates the fair values of its derivatives on a monthly basis using an option-pricing model. To utilize the option-pricing model, the Company uses various factors that include closing exchange prices on the NYMEX, over-the-counter quotations, volatility and the time value of options. The estimated future prices are compared to the prices fixed by the hedge agreements, and the resulting estimated future cash inflows (outflows) over the lives of the hedges are discounted using the Company's current borrowing rates under its revolving credit facility. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts, regional price differentials and interest rates. Historically, the majority of the Company's derivative instruments have been hedges of the price of crude oil and natural gas production. The Company is not involved in any derivative trading activities.

Business Combinations/Acquisitions

In 2001, the Company grew substantially through the acquisition of North Central. As stated earlier, this acquisition was accounted for using the purchase method of accounting, and current accounting pronouncements require that all future acquisitions be accounted for using the purchase method.

Under the purchase method, the acquiring company adds to its balance sheet the estimated fair values of the acquired company's assets and liabilities. Any excess of the purchase price over the fair values of the tangible and intangible net assets acquired is recorded as goodwill. As of January 1, 2002, the accounting for goodwill changed. In prior years, goodwill was amortized. Effective January 1, 2002, goodwill and other intangibles with an indefinite useful life are no longer amortized, but instead are assessed for impairment

at least annually. The Company has never recorded any goodwill in connection with its business combinations/acquisitions. However, there can be no assurance that the Company will not do so in the future.

There are various assumptions made by the Company in determining the fair values of an acquired company's assets and liabilities. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of the oil and gas properties acquired. To determine the fair values of these properties, the Company prepares estimates of oil, natural gas and NGL reserves. These estimates are based on work performed by the Company's engineers and outside petroleum reservoir consultants. The judgments associated with the estimation of reserves are described earlier in this section. The fair value of the estimated reserves acquired in a business combination is then calculated based on the Company's estimates of future oil, natural gas and NGL prices. The Company's estimates of future prices are based on its own analysis of pricing trends. These estimates are based on current data obtained with regard to regional and worldwide supply and demand dynamics, such as economic growth forecasts. They are also based on industry data regarding natural gas storage availability, drilling rig activity, changes in delivery capacity and trends in regional pricing differentials. Future price forecasts from independent third parties are also taken into account in arriving at the Company's own pricing estimates. The Company's estimates of future prices are applied to the estimated reserve quantities acquired to arrive at estimated future net revenues. For estimated proved reserves, the future net revenues are then discounted to derive a fair value for such reserves. The Company also applies these same general principles in arriving at the fair value of unproved reserves acquired in a business combination. These unproved reserves are generally classified as either probable or possible reserves. Because of their very nature, probable and possible reserve estimates are less precise than those of proved reserves. Generally, in the Company's business combinations, the determination of the fair values of oil and gas properties requires more judgment than the estimates of fair values for other acquired assets and liabilities.

Future Development and Abandonment Costs

Future development costs include costs incurred to obtain access to proved reserves, including drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, FPSOs, FSOs, gathering systems, wells and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. The Company reviews its assumptions and estimates of future abandonment costs on an annual basis. The accounting for future abandonment costs changed on January 1, 2003, with the adoption of SFAS 143. SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized.

Pension and Other Post-Retirement Benefits

Accounting for pensions and other postretirement benefits involves several assumptions including the expected rates of return on plan assets, determination of discount rates for remeasuring plan obligations, determination of inflation rates regarding compensation levels and health care cost projections. The Company develops its demographics and utilizes the work of actuaries to assist with the measurement of employee-related obligations. The assumptions used vary from year-to-year, which will affect future results

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of operations. Any differences among these assumptions and the results actually experienced will also impact future results of operations.

Income Taxes

For financial reporting purposes, the Company generally provides taxes at the rate applicable for the appropriate tax jurisdiction. Where the Company's present intention is to reinvest the unremitted earnings in its foreign operations, the Company does not provide for U.S. income taxes on unremitted earnings of foreign subsidiaries. Management periodically assesses the need to utilize these unremitted earnings to finance the foreign operations of the Company. This assessment is based on cash flow projections that are the result of estimates of future production, commodity pricing and expenditures by tax jurisdiction for the Company's operations. Such estimates are inherently imprecise since many assumptions utilized in the cash flow projections are subject to revision in the future.

Management also periodically assesses, by tax jurisdiction, the probability of recovery of recorded deferred tax assets based on its assessment of future earnings outlooks. Such estimates are inherently imprecise since many assumptions utilized in the assessments are subject to revision in the future.

Other Matters

Inflation. Publicly held companies are asked to comment on the effects of inflation on their business. Currently annual inflation in terms of the decrease in the general purchasing power of the dollar is running well below the general annual inflation rates experienced in the past. While the Company, like other companies, continues to be affected by fluctuations in the purchasing power of the dollar due to inflation, such effect is not currently considered significant.

Southeast Asia Economic Issues. A substantial portion of the Company's oil and gas operations are conducted in Southeast Asia, and a substantial portion of its natural gas and liquid hydrocarbon production is sold there. As with most emerging market economies, the Thai economy is particularly sensitive to worldwide economic trends. The economic health of the Thai economy and its effect on the volatility of the Thai Baht against the dollar will continue to have a material impact on the Company's operations in the Kingdom of Thailand, together with the prices that the Company receives for its oil and natural gas production there. See "Results of Operations; Oil and Gas Revenues".

All of the Company's current natural gas production from the Thailand Concession is committed under a long-term Gas Sales Agreement, in each case to PTT at prices denominated in Thai Baht which are determined in accordance with a formula that is intended to ameliorate, at least in part, any decline in the purchasing power of the Thai Baht against the dollar. See "Business International Operations; Contractual Terms Governing the Thailand Concession" and "Business Miscellaneous; Sales." Although the Company currently believes that PTT will honor its commitments under the Gas Sales Agreement, a failure by PTT to honor such commitments could have a material adverse effect on the Company. During 2001, the government of Thailand partially privatized the Petroleum Authority of Thailand, forming PTT and retaining an ownership interest of approximately 70%. PTT is a publicly traded entity that currently constitutes one of the largest public companies in the Kingdom of Thailand. However, its contractual obligations are no longer backed by the full faith and credit of the Thai government.

The Company's crude oil and condensate production from the Thailand Concession is currently sold on a tanker load by tanker load basis. Prices that the Company receives for such production are based on world benchmark prices, which are denominated in dollars, and are typically paid in dollars. See "Business International Operations; Contractual Terms Governing the Thailand Concession and Related Production" and "Business Miscellaneous; Sales."

Recent Accounting Pronouncements

The Financial Accounting Standards Board ("FASB") has issued several new pronouncements, including Interpretation No. 46 (revised December 2003) ("FIN 46R"), "Consolidation of Variable Interest Entities, an interpretation of ARB 51", Statement of Financial Accounting Standards No. 149 ("SFAS 149"), "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" and Statement of Financial Accounting Standards No. 150 ("SFAS 150"), "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity".

FIN 46R. The primary objectives of FIN 46R are to provide guidance on the identification of entities for which control is achieved through means other than through voting rights (these entities are referred to as "variable interest entities" or "VIEs") and how to determine if a business enterprise should consolidate the VIEs. This new model for consolidation applies to an entity for which either:

- the equity investors (if any) do not have a controlling financial interest; or

- the equity investment at risk is insufficient to finance the entity's activities without receiving additional subordinated financial support from other parties.

In addition, FIN 46R requires that all enterprises with a significant variable interest in a VIE make additional disclosures regarding their relationship with the VIE. The interpretation requires public entities to apply FIN 46R to all entities that are considered SPEs in practice and under the FASB literature that was applied before the issuance of FIN 46R by the end of the first reporting period that ends after December 15, 2003. Application of the accounting requirements of the interpretation to all other entities is required by the end of the first reporting period that ends after March 15, 2004. The adoption of FIN 46R had no effect on the Company's financial statements.

SFAS 149. SFAS 149 amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts and hedging activities under SFAS 133. The amendments set forth in SFAS 149 require that contracts with comparable characteristics be accounted for similarly. SFAS 149 is generally effective for contracts entered into or modified after June 30, 2003 (with limited exceptions) and for hedging relationships designated after June 30, 2003. The guidance is to be applied prospectively only. The adoption of SFAS 149 did not have a material effect on the Company's financial statements.

SFAS 150. SFAS 150 establishes standards for classification and measurement of certain financial instruments with characteristics of both liabilities and equity on a Company's balance sheet. SFAS 150 requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances) because that financial instrument embodies an obligation of the issuer. Many of those instruments were previously classified as equity. SFAS 150 was effective for financial instruments entered into after May 31, 2003. The adoption of SFAS 150 had no effect on the Company's financial statements.

Other. The Company has been made aware that an issue has arisen regarding the application of provisions of SFAS No. 141, "Business Combinations" and SFAS No. 142, "Goodwill and Other Intangible Assets" ("SFAS 142") to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS 142 requires registrants to reclassify costs associated with mineral rights, including both proved and unproved leasehold acquisition costs, as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs. Historically, the Company and other oil and gas companies have included the cost of these oil and gas leasehold interests as part of oil and gas properties and provided the disclosures required by SFAS No. 69, "Disclosures about Oil and Gas Producing Activities" ("SFAS 69"). Also under consideration is whether SFAS 142 requires registrants to provide the additional disclosures prescribed by SFAS 142 for intangible assets for costs associated with mineral rights.

The Emerging Issues Task Force ("EITF") has recently decided to consider this issue. If the EITF determines that SFAS 142 requires the Company to reclassify costs associated with mineral rights from property and equipment to intangible assets, the Company currently believes that its results of operations and financial condition would not be affected, since such intangible assets would continue to be depleted and assessed for impairment in accordance with existing successful efforts accounting rules and impairment standards. In addition, costs associated with mineral rights would continue to be characterized as oil and gas property costs in the Company's required disclosures under SFAS 69.

At December 31, 2003, the Company had undeveloped leaseholds of approximately $74 million that would be classified on the balance sheet as "intangible undeveloped leaseholds" and developed leaseholds of approximately $1,131 million (net of accumulated depletion) that would be classified as "intangible developed leaseholds" if the Company applied the interpretation currently being discussed.

ITEM 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

The Company is exposed to market risk, including adverse changes in commodity prices, interest rates and foreign currency exchange rates as discussed below.

Commodity Price Risk

The Company produces, purchases and sells natural gas, crude oil, condensate and NGLs. As a result, the Company's financial results can be significantly affected as these commodity prices fluctuate widely in response to changing market forces. In the past, the Company has made limited use of a variety of derivative financial instruments only for non-trading purposes as a hedging strategy to manage commodity prices associated with oil and gas sales and to reduce the impact of commodity price fluctuations. See "Business Competition and Market Conditions."

Interest Rate Risk

From time to time, the Company has entered into various financial instruments, such as interest rate swaps, to manage the impact of changes in interest rates. As of February 18, 2004, the Company has no open interest rate swap or interest rate lock agreements. Therefore, the Company's exposure to changes in interest rates primarily results from its short-term and long-term debt with both fixed and floating interest rates. The following table presents principal or notional amounts (stated in thousands) and related average interest rates by year of maturity for the Company's debt obligations and their indicated fair market value at December 31, 2003:

	2004	2005	2006	2007	2008	Thereafter	Total	Fair Value
Long-Term Debt:								
Variable Rate	$ 0	$ 0	$ 139,000	$ 0	$ 0	$ 0	$ 139,000	$ 139,000
Average Interest Rate			2.31%				2.31%	
Fixed Rate	$ 0	$ 0	$ 0	$ 0	$ 0	$ 350,000	$ 350,000	$ 380,250
Average Interest Rate						9.16%	9.16%	

Foreign Currency Exchange Rate Risk

In addition to the U.S. dollar, the Company and certain of its subsidiaries conduct their business in Thai Baht and Hungarian Forint and are therefore subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing and investing transactions. The Company conducts a substantial portion of its oil and gas production and sales in Southeast Asia. Southeast Asia in general, and the Kingdom of Thailand in particular, have experienced severe economic difficulties in the recent past, including sharply reduced economic activity, illiquidity, highly volatile foreign currency exchange rates and unstable stock markets. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources; Other Matters; Southeast Asia Economic Issues." The economic situation in Thailand and the volatility of the Thai Baht against the dollar could have a material impact on the Company's Thailand operations and prices that the Company receives for its natural gas

production there. Although the Company's sales to PTT under the Gas Sales Agreement are denominated in Baht, because predominantly all of the Company's crude oil sales and its capital and most other expenditures in the Kingdom of Thailand are denominated in U.S. dollars, the U.S. dollar is the functional currency for the Company's operations in the Kingdom of Thailand. As of February 18, 2004, the Company is not a party to any foreign currency exchange agreement.

Exposure from market rate fluctuations related to activities in Hungary, where the Company's functional currency is the U.S. dollar, is not material at this time.

Current Hedging Activity

From time to time, the Company has used and expects to continue to use hedging transactions with respect to a portion of its oil and gas production to achieve a more predictable cash flow, as well as to reduce its exposure to price fluctuations. While the use of these hedging arrangements limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The use of hedging transactions also involves the risk that the counter-parties will be unable to meet the financial terms of such transactions. All of the Company's recent historical hedging transactions have been carried out in the over-the-counter market with investment grade institutions. As of February 18, 2004, the Company was not a party to any commodity price contracts with respect to any of its current or future crude oil and condensate or natural gas production.

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

REPORT OF INDEPENDENT AUDITORS

To the Shareholders and Board of
Directors of Pogo Producing Company:

In our opinion, the accompanying consolidated balance sheets as of December 31, 2003 and 2002, and the related consolidated statements of income, shareholders' equity and cash flows present fairly, in all material respects, the financial position of Pogo Producing Company (the "Company") and its subsidiaries at December 31, 2003 and 2002 and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America. 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 of these statements in accordance with auditing standards generally accepted in the United States of America, which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion. The financial statements of the Company for the year ended December 31, 2001, were audited by other independent accountants who have ceased operations. Those independent accountants expressed an unqualified opinion on those financial statements in their report dated February 28, 2002.

As discussed in Note 1 to the financial statements, the Company changed its method of accounting for employee stock-based compensation, effective January 1, 2003. As discussed in Note 11 to the financial statements, the Company changed its method of accounting for asset retirement costs, effective January 1, 2003.

PRICEWATERHOUSECOOOPERS LLP

Houston, Texas
February 24, 2004

REPORTS OF INDEPENDENT PUBLIC ACCOUNTANTS

THE FOLLOWING REPORT IS A COPY OF THE PREVIOUSLY ISSUED REPORT FROM ARTHUR ANDERSEN LLP (ANDERSEN). ANDERSEN DID NOT PERFORM ANY PROCEDURES IN CONNECTION WITH THIS ANNUAL REPORT ON FORM 10-K. ACCORDINGLY, THIS REPORT HAS NOT BEEN REISSUED BY ANDERSEN.

To the Shareholders and Board of
Directors of Pogo Producing Company:

We have audited the accompanying consolidated balance sheets of Pogo Producing Company (a Delaware corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, cash flows and shareholders' equity for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Pogo Producing Company and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As explained in Note 1 to the financial statements, effective January 1, 2001, the Company changed its method of accounting for derivative instruments and hedging activities. In addition, effective January 1, 2000, the Company changed its method of accounting for product inventory.

ARTHUR ANDERSEN LLP

Houston, Texas
February 28, 2002

POGO PRODUCING COMPANY & SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2003	**2002**	**2001**
	(Expressed in thousands, except per share amounts)		
Revenues:			
Oil and gas	$ 1,159,544	$ 750,401	$ 596,077
Other	2,452	4,453	14,040
Total	1,161,996	754,854	610,117
Operating Costs and Expenses:			
Lease operating	123,098	112,663	92,693
General and administrative	61,291	49,490	39,162
Exploration	7,547	4,783	23,373
Dry hole and impairment	35,102	26,999	26,945
Depreciation, depletion and amortization	325,820	287,809	206,609
Production and other taxes	35,485	20,058	22,007
Transportation and other	25,924	12,879	19,447

	Year Ended December 31,		
Total	614,267	514,681	430,236
Operating Income	547,729	240,173	179,881
Interest:			
Charges	(46,360)	(57,450)	(56,259)
Income	1,852	1,760	3,226
Capitalized	16,531	24,033	33,242
Loss on debt extinguishment	(5,893)		
Minority Interest Dividends and costs associated with mandatorily redeemable convertible preferred securities of a subsidiary trust		(4,140)	(9,999)
Foreign Currency Transaction Gain (Loss)	1,370	435	(524)
Income Before Taxes and Cumulative Effect of Change in Accounting Principle	515,229	204,811	149,567
Income Tax Expense	(220,122)	(97,780)	(61,613)
Income Before Cumulative Effect of Change in Accounting Principle	295,107	107,031	87,954
Cumulative Effect of Change in Accounting Principle	(4,166)		
Net Income	$ 290,941	$ 107,031	$ 87,954
Earnings (Loss) per Common Share:			
Basic			
Income before cumulative effect of change in accounting principle	$ 4.72	$ 1.85	$ 1.72
Cumulative effect of change in accounting principle	(0.07)		
Net income	$ 4.65	$ 1.85	$ 1.72
Diluted			
Income before cumulative effect of change in accounting principle	$ 4.60	$ 1.77	$ 1.62
Cumulative effect of change in accounting principle	(0.06)		
Net income	$ 4.54	$ 1.77	$ 1.62
Dividends per Common Share	$ 0.20	$ 0.12	$ 0.12

The accompanying notes to consolidated financial statements are an integral part hereof.

POGO PRODUCING COMPANY & SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

December 31,

	2003	2002
	(Expressed in thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 178,754	$ 134,449
Accounts receivable	116,970	101,807
Other receivables	39,497	14,634
Deferred income tax		20,041
Inventory product	5,951	2,501
Inventories tubulars	7,735	9,406
Other	5,448	4,818
Total current assets	354,355	287,656
Property and Equipment:		
Oil and gas, on the basis of successful efforts accounting		
Proved properties	3,919,138	3,396,669
Unevaluated properties	107,708	141,094
Other, at cost	30,046	26,626
	4,056,892	3,564,389
Accumulated depreciation, depletion, and amortization		
Oil and gas	(1,661,584)	(1,389,976)
Other	(19,467)	(15,364)
	(1,681,051)	(1,405,340)
Property and equipment, net	2,375,841	2,159,049
Other Assets:		
Deferred income tax	2,416	2,416
Foreign value added taxes receivable	4,188	13,908
Other	25,236	28,564
	31,840	44,888
	$ 2,762,036	$ 2,491,593

The accompanying notes to consolidated financial statements are an integral part hereof.

POGO PRODUCING COMPANY & SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2003	December 31, 2002
	(Expressed in thousands)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable operating activities	$ 55,543	$ 41,102
Accounts payable investing activities	73,179	68,963
Income taxes payable	20,220	15,527
Accrued interest payable	9,950	11,096
Accrued payroll and related benefits	3,242	3,011
Deferred income tax	5,324	5,324
Other	16,126	4,662
Total current liabilities	183,584	149,685
Long-Term Debt	487,261	722,903
Deferred Income Tax	546,709	526,897
Asset Retirement Obligation	70,790	
Other Liabilities and Deferred Credits	20,039	14,324
Total liabilities	1,308,383	1,413,809
Commitments and Contingencies (Note 5)		
Shareholders' Equity:		
Preferred stock, $1 par; 4,000,000 shares authorized		
Common stock, $1 par; 200,000,000 shares authorized, and and 63,813,283 and 61,061,888 shares issued, respectively	63,813	61,062
Additional capital	914,492	822,526
Retained earnings	480,576	202,155
Accumulated other comprehensive income (loss)		(6,249)
Deferred compensation	(3,518)	
Treasury stock (55,359 shares), at cost	(1,710)	(1,710)
Total shareholders' equity	1,453,653	1,077,784
	$ 2,762,036	$ 2,491,593

The accompanying notes to consolidated financial statements are an integral part hereof.

POGO PRODUCING COMPANY & SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2003	**2002**	**2001**
	(Expressed in thousands)		
Cash flows from operating activities:			
Cash received from customers	$ 1,180,901	$ 701,429	$ 625,538
Operating, exploration and general and administrative expenses paid	(229,355)	(199,104)	(205,004)
Income taxes paid	(164,008)	(19,287)	(31,115)
Income taxes received		25,884	1,381
Interest paid	(45,527)	(55,526)	(48,458)
Cash received (paid) related to price hedge contracts	(15,037)	14,931	20,142
Value added taxes (paid) received	9,720	(7,708)	1,062
Other	7,865	5,860	4,530
Net cash provided by operating activities	744,559	466,479	368,076
Cash flows from investing activities:			
Capital expenditures	(335,615)	(368,466)	(386,164)
Purchase of properties	(189,083)		(2,714)
Proceeds from the sale of property and tubular stock	521	4,215	9,243
Acquisition of NORIC, net of $21,235,000 cash acquired			(323,476)
Proceeds from the sale of Canadian subsidiary			13,739
Net cash used in investing activities	(524,177)	(364,251)	(689,372)
Cash flows from financing activities:			
Borrowings under senior debt agreements	854,012	703,077	1,322,990
Payments under senior debt agreements	(875,000)	(773,080)	(1,093,000)
Redemption of debt	(176,578)		
Proceeds from exercise of stock options	33,370	20,154	7,469
Payment of cash dividends on common stock	(12,520)	(6,895)	(6,047)
Proceeds from issuance of new debt			200,000
Payment of North Central senior debt acquired			(78,600)
Payment of preferred dividends of a subsidiary trust		(4,850)	(9,750)
Payment of financing issue costs and other	(100)	(329)	(8,720)
Net cash (used in) provided by financing activities	(176,816)	(61,923)	334,342
Effect of exchange rate changes on cash	739	(150)	(262)
Net increase in cash and cash equivalents	44,305	40,155	12,784
Cash and cash equivalents at the beginning of the year	134,449	94,294	81,510

	Year Ended December 31,		
Cash and cash equivalents at the end of the year	$ 178,754	$ 134,449	$ 94,294
Reconciliation of net income to net cash provided by operating activities:			
Net income	$ 290,941	$ 107,031	$ 87,954
Adjustments to reconcile net income to net cash provided by operating activities			
Cumulative effect of change in accounting principle	4,166		
Minority interest		4,140	9,999
Gains on sales	(386)	(3,034)	(1,000)
Depreciation, depletion and amortization	325,820	287,809	206,609
Dry hole and impairment	35,102	26,999	26,945
Interest capitalized	(16,531)	(24,033)	(33,242)
Price hedge contracts	8,346	17,589	5,550
Other	25,989	728	524
Increase (decrease) in deferred income taxes	51,818	70,929	50,617
Change in assets and liabilities:			
(Increase) decrease in accounts receivable	(14,990)	(50,521)	40,436
Increase in federal income taxes receivable			(22,809)
(Increase) decrease in inventory product	(1,422)	173	12
Increase in other current assets	(623)	(12,571)	(534)
(Increase) decrease in other assets	11,502	(6,784)	6,257
Increase (decrease) in accounts payable	14,606	6,170	(17,786)
Increase in income taxes payable	4,347	33,610	3,684
Increase (decrease) in accrued interest payable	(1,133)	(352)	4,010
Increase in accrued payroll and related benefits	234	343	385
Increase (decrease) in other current liabilities	993	6,377	(241)
Increase in deferred credits	5,780	1,876	706
Net cash provided by operating activities	$ 744,559	$ 466,479	$ 368,076

The accompanying notes to consolidated financial statements are an integral part hereof.

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POGO PRODUCING COMPANY & SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(Expressed in thousands)

	Common Stock(a)	Additional Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Deferred Compensation Restricted Stock	Treasury Stock	Shareholders' Equity	Comprehensive Income (Loss)
Balance at December 31, 2000	40,660	$ 298,885	$ 20,112	$ (1,062)	$	$ (324)	$ 358,271	
Net income			87,954				87,954	$ 87,954
Shares issued for stock and debt of acquired company	12,615	351,729					364,344	
Exercise of stock options	378	7,718					8,096	

	Common Stock(a)	Additional Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Deferred Compensation Restricted Stock	Treasury Stock	Shareholders' Equity	Comprehensive Income (Loss)
Shares issued as compensation	38	895					933	
Dividends ($0.12 per common share)			(6,047)				(6,047)	
Exchange gain on Canadian currency				389			389	389
Reclassification adjustment included in net income				673			673	(389)
Cumulative effect of change in accounting principle				(2,438)			(2,438)	(2,438)
Unrealized gains arising during the year on price hedge contracts				22,195			22,195	
Reclassification adjustment included in net income				(9,485)			(9,485)	
Net unrealized gains on price hedge contracts								12,710
Comprehensive income								$ 98,226
Balance at December 31, 2001	53,691	$ 659,227	$ 102,019	$ 10,272	$	$ (324)	$ 824,885	
Net income			107,031				107,031	$ 107,031
Exercise of stock options	1,022	23,460					24,482	
Shares issued as compensation	39	1,124					1,163	
Conversion of Trust Preferred Securities	6,310	138,715					145,025	
Dividends ($0.12 per common share)			(6,895)				(6,895)	
Shares received in satisfaction of note receivable						(1,386)	(1,386)	
Unrealized loss arising during the year on price hedge contracts				(14,155)			(14,155)	
Reclassification adjustment included in net income				(2,366)			(2,366)	
Net unrealized losses on price hedge contracts								(16,521)
Comprehensive income								$ 90,510
Balance at December 31, 2002	61,062	$ 822,526	$ 202,155	$ (6,249)	$	$ (1,710)	$ 1,077,784	
Net income			290,941				290,941	$ 290,941
Stock option activity and other	1,573	43,915					45,488	
Shares issued as compensation	170	6,865					7,035	
Conversion of 2006 Notes	1,008	41,186					42,194	
					(3,518)		(3,518)	(3,518)

	Common Stock(a)	Additional Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Deferred Compensation Restricted Stock	Treasury Stock	Shareholders' Equity	Comprehensive Income (Loss)
Issuance of restricted stock, less amortization of $412								
Dividends ($0.20 per common share)			(12,520)				(12,520)	
Unrealized loss arising during the year on price hedge contracts				(8,624)			(8,624)	
Reclassification adjustment included in net income				14,873			14,873	
Net unrealized gains on price hedge contracts								6,249
Comprehensive income								$ 293,672
Balance at December 31, 2003	63,813	$ 914,492	$ 480,576	$	$ (3,518)	$ (1,710)	$ 1,453,653	

(a) Reflects both dollar and share amounts at $1.00 par value.

The accompanying notes to consolidated financial statements are an integral part hereof.

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POGO PRODUCING COMPANY & SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Nature of Operations

Pogo Producing Company was incorporated in 1970. Pogo Producing Company and its subsidiaries (the "Company") are engaged in oil and gas exploration, development, production and acquisition activities in the United States, both offshore in the Gulf of Mexico (primarily in federal waters offshore Louisiana and Texas) and onshore principally in the states of New Mexico, Texas, Louisiana and Wyoming. The Company also conducts exploration, development and production activities internationally in the Kingdom of Thailand (offshore in the Gulf of Thailand) and exploration activities in Hungary, New Zealand and the Danish sector of the North Sea.

Use of Estimates

The preparation of these financial statements requires the use of certain estimates by management in determining the Company's assets, liabilities, revenues and expenses. Actual results could differ from such estimates. Depreciation, depletion and amortization of oil and gas properties and the impairment of oil and gas properties are determined using estimates of oil and gas reserves. There are numerous uncertainties in estimating the quantity of reserves and in projecting the future rates of production and timing of development expenditures. Oil and gas reserve engineering must be recognized as a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way. Proved reserves of crude oil, condensate, natural gas and natural gas liquids are estimated quantities that geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under existing conditions.

Principles of Consolidation

The consolidated financial statements include the accounts of Pogo Producing Company and its subsidiaries and affiliates, after elimination of all significant intercompany transactions. Majority owned subsidiaries are fully consolidated. Minority owned oil and gas affiliates are pro rata consolidated in the same manner as the Company accounts for its operating or working interest in oil and gas joint ventures.

Revenue Recognition

The Company follows the "sales" (takes or cash) method of accounting for oil and gas revenues. Under this method, the Company recognizes revenues on production as it is taken and delivered to its purchasers. The volumes sold may be more or less than the volumes the Company is entitled to based on its ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. At December 31, 2003, the Company had taken approximately 1,030 MMcf of natural gas less than it was entitled to based on its interest in certain properties, and approximately 798 MMcf more than its entitlement on other properties, placing the Company in a net under-delivered position of approximately 232 MMcf of natural gas based on its working interest ownership in such properties. The Company's crude oil imbalances are not significant. Such imbalances are reflected as adjustments to proved reserves and future cash flows in the unaudited supplementary oil and gas data included herein.

Inventory Product

Crude oil and condensate from the Company's producing fields located in the Kingdom of Thailand are produced into storage vessels and are sold and recognized as revenue periodically as economic quantities are accumulated. The product inventory at December 31, 2003 consists of approximately 495,452

barrels of crude oil and condensate, net to the Company's interest, and is carried at the Company's estimated average cost of $12.01 per barrel. The product inventory at December 31, 2002 consisted of approximately 202,397 barrels of crude oil and condensate, net to the Company's interest, and is carried at its estimated average cost of $12.35 per barrel.

Inventories Tubulars

Tubular inventories consist primarily of goods used in the Company's operations and are stated at the lower of average cost or market value.

Oil and Gas Activities and Depreciation, Depletion and Amortization

The Company follows the successful efforts method of accounting for its oil and gas activities. Under the successful efforts method, lease acquisition costs and all development costs are capitalized. Proved oil and gas properties are reviewed annually or when circumstances suggest the need for such a review and, if required, the proved properties are written down to their estimated fair value. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. Estimated fair value includes the estimated present value of all reasonably expected future production, prices, and costs. Exploratory drilling costs are capitalized until the results are determined. If proved reserves are not discovered, the exploratory drilling costs are expensed. Interest costs related to financing major oil and gas projects in progress are capitalized until the projects are evaluated or until the projects are substantially complete and ready for their intended use if the projects are evaluated as successful. Other exploratory costs are expensed as incurred. The provision for depreciation, depletion and amortization is based on the capitalized costs as determined above, and is computed on a cost center by cost center basis using the units of production method, with lease acquisition costs amortized over total proved reserves and other costs amortized over proved developed reserves. The Company generally creates cost centers on a field-by-field basis for oil and gas activities in the Gulf of Mexico and the Gulf of Thailand. Generally, the Company establishes cost centers on the basis of an oil or gas trend or play for its onshore oil and gas activities. As described further below, the Company's method of accounting for asset retirement obligations (i.e. future abandonment costs) changed effective January 1, 2003.

The Company has an ongoing asset rationalization process. In connection with this process, the Company has from time to time disposed of certain non-core properties and other assets that it considers to be under performing, to have little or no remaining upside potential, or which face significant future expenditures that would result in an unacceptable rate of return. Refer to the captions "Gains on sales" and "Proceeds from the sale of property and tubular stock" in the Consolidated Statements of Cash Flows.

Other properties and equipment are depreciated using a straight-line method in amounts which, in the opinion of management, are adequate to allocate the cost of the properties over their estimated useful lives.

Income Taxes

Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective. Deferred tax assets are reduced by a valuation allowance for the amount of any tax benefit the Company does not expect to be realized. Note 3 contains information about the Company's income taxes, including the components of income tax provision and the composition of deferred income tax assets and liabilities.

Price Risk Management

The Company from time to time enters into commodity price hedging contracts with respect to its oil and gas production to achieve a more predictable cash flow, as well as reduce its exposure to price volatility. Effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133").

SFAS 133, as amended, established accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. The statement requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting. Based on the nature of derivative instruments used by the Company and the historical volatility of oil and gas commodity prices, the Company expects that SFAS 133 could increase volatility in the Company's earnings and other comprehensive income for future periods during which derivative instruments are outstanding.

SFAS 133 provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, must be recognized currently in earnings

SFAS 133 requires that as of the date of initial adoption, the difference between the fair value of derivative instruments and the previous carrying amount of these derivatives be recorded in net income or other comprehensive income, as appropriate, as the cumulative effect of a change in accounting principle. Upon adoption, the Company determined that the cumulative effect of adopting SFAS 133 should be recorded in other comprehensive income. The Company adopted SFAS 133 effective January 1, 2001 and recorded an unrealized loss of $2,438,000, net of deferred taxes of $1,313,000, in other comprehensive income (loss).

Accounting for Stock-Based Compensation

The Company's incentive plans authorize awards granted wholly or partly in common stock (including rights or options which may be exercised for or settled in common stock) to key employees and non-employee directors (collectively, "Stock Awards"). Prior to January 1, 2003, the Company accounted for Stock Awards using the intrinsic value recognition provisions of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Under this method, the Company recognized no compensation expense for stock options granted when the exercise price of the options was equal to or greater than the quoted market price of the Company's common stock on the grant date. Effective January 1, 2003, the Company adopted the fair value recognition provisions of SFAS No. 123, "Accounting for Stock Based Compensation" ("SFAS 123"), and the prospective method transition provisions of SFAS No. 148, "Accounting for Stock Based Compensation Transition and Disclosure an amendment of FAS No. 123" ("SFAS 148"), for all Stock Awards granted, modified or settled after January 1, 2003. Compensation cost for stock options and other stock-based compensation is recognized on a straight-line basis over the vesting period for the applicable Stock Award. The Company granted Stock Awards covering 547,000 shares of common stock with a fair market value of $9,920,000 during the year ended December 31, 2003.

The following table illustrates the effect on the Company's net income and earnings per share if the fair value recognition provisions of SFAS 123 for employee stock-based compensation had been applied to all Stock Awards outstanding during the years ended December 31, 2003, 2002 and 2001 (in thousands of dollars, except per share amounts):

	Year Ended December 31,		
	2003	2002	2001
Net income, as reported	$ 290,941	$ 107,031	$ 87,954
Add: Employee stock-based compensation expense, net of related tax effects, included in net income, as reported	1,408	756	606
Deduct: Total employee stock-based compensation expense, determined under fair value method for all awards, net of related tax effects	(7,017)	(6,466)	(5,115)
Net income, pro forma	$ 285,332	$ 101,321	$ 83,445
Earnings per share:			
Basic as reported	$ 4.65	$ 1.85	$ 1.72
Basic pro forma	$ 4.56	$ 1.75	$ 1.64
Diluted as reported	$ 4.54	$ 1.77	$ 1.62
Diluted pro forma	$ 4.45	$ 1.68	$ 1.54

The fair value of grants was estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used in 2003, 2002 and 2001, respectively: risk free interest rates of 2.30%, 4.20% and 4.85%, expected volatility of 28.4%, 33.9% and 44.41%, dividend yields of 0.61%, 0.51% and 0.49%, and an expected life of the options of three, seven and six years.

Consolidated Statements of Cash Flows

For the purpose of cash flows, the Company considers all highly liquid investments with a maturity date of three months or less to be cash equivalents. Significant transactions may occur which do not directly affect cash balances and, as such, are not disclosed in the Consolidated Statements of Cash Flows. Certain such non-cash transactions are disclosed in the Consolidated Statements of Shareholders' Equity relating to shares issued as compensation, and shares issued for stock and debt of an acquired company. The shares issued for stock of an acquired company are also discussed in Note 12, "Acquisition".

Foreign Currency

The U.S. dollar is the functional currency for all areas of operations of the Company. Accordingly, monetary assets and liabilities and items of income and expense denominated in a foreign currency are remeasured to U.S. dollars at the rate of exchange in effect at the end of each month or the average for the month, and the resulting gains or losses on foreign currency transactions are included in the consolidated statements of income for the period.

Prior Year Reclassifications

Certain prior year amounts have been reclassified to conform with the current year presentation. Such reclassifications had no effect on the Company's operating income, net income or shareholders' equity.

Recent Accounting Pronouncements

The Financial Accounting Standards Board ("FASB") has issued several new pronouncements including Interpretation No. 46 (revised December 2003) ("FIN 46R"), "Consolidation of Variable Interest Entities, an interpretation of ARB 51", Statement of Financial Accounting Standards No. 149 ("SFAS 149"), "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" and Statement of Financial Accounting Standards No. 150 ("SFAS 150"), "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity".

FIN 46R. The primary objectives of FIN 46R are to provide guidance on the identification of entities for which control is achieved through means other than through voting rights (these entities are referred to as "variable interest entities" or "VIEs") and how to determine if a business enterprise should consolidate the VIEs. This new model for consolidation applies to an entity for which either:

- the equity investors (if any) do not have a controlling financial interest; or

- the equity investment at risk is insufficient to finance the entity's activities without receiving additional subordinated financial support from other parties.

In addition, FIN 46R requires that all enterprises with a significant variable interest in a VIE make additional disclosures regarding their relationship with the VIE. The interpretation requires public entities to apply FIN 46R to all entities that are considered SPEs in practice and under the FASB literature that was applied before the issuance of FIN 46R by the end of the first reporting period that ends after December 15, 2003. Application of the accounting requirements of the interpretation to all other entities is required by the end of the first reporting period that ends after March 15, 2004. The adoption of FIN 46R had no effect on the Company's financial statements.

SFAS 149. SFAS 149 amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts and hedging activities under SFAS 133. The amendments set forth in SFAS 149 require that contracts with comparable characteristics be accounted for similarly. SFAS 149 is generally effective for contracts entered into or modified after June 30, 2003 (with limited exceptions) and for hedging relationships designated after June 30, 2003. The guidance is to be applied prospectively only. The adoption of SFAS 149 did not have a material effect on the Company's financial statements.

SFAS 150. SFAS 150 establishes standards for classification and measurement of certain financial instruments with characteristics of both liabilities and equity on a Company's balance sheet. SFAS 150 requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances) because that financial instrument embodies an obligation of the issuer. Many of those instruments were previously classified as equity. SFAS 150 was effective for financial instruments entered into after May 31, 2003. The adoption of SFAS 150 had no effect on the Company's financial statements.

Other. The Company has been made aware that an issue has arisen regarding the application of provisions of SFAS No. 141, "Business Combinations" and SFAS No. 142, "Goodwill and Other Intangible Assets" ("SFAS 142") to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS 142 requires registrants to reclassify costs associated with mineral rights, including both proved and unproved leasehold acquisition costs, as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs. Historically, the Company and other oil and gas companies have included the cost of these oil and gas leasehold interests as part of oil and gas properties and provided the disclosures required by SFAS No. 69, "Disclosures about Oil and Gas Producing Activities" ("SFAS 69").

Also under consideration is whether SFAS 142 requires registrants to provide the additional disclosures prescribed by SFAS 142 for intangible assets for costs associated with mineral rights.

The Emerging Issues Task Force ("EITF") has recently decided to consider this issue. If the EITF determines that SFAS 142 requires the Company to reclassify costs associated with mineral rights from property and equipment to intangible assets, the Company currently believes that its results of operations and financial condition would not be affected, since such intangible assets would continue to be depleted and assessed for impairment in accordance with existing successful efforts accounting rules and impairment standards. In addition, costs associated with mineral rights would continue to be characterized as oil and gas property costs in the Company's required disclosures under SFAS 69.

At December 31, 2003, the Company had undeveloped leaseholds of approximately $74 million that would be classified on the balance sheet as "intangible undeveloped leaseholds" and developed leaseholds of approximately $1,131 million (net of accumulated depletion) that would be classified as "intangible developed leaseholds" if the Company applied the interpretation currently being discussed.

(2) Earnings per Share

Earnings per common share (basic earnings per share) are based on the weighted average number of shares of common stock outstanding during the periods. Earnings per common share and potential common share (diluted earnings per share) consider the effect of dilutive securities as set out below in thousands, except per share amounts.

	For the Year Ended December 31, 2003		
	Income(a)	Shares	Per Share
Basic earnings per share	$ 295,107	62,538	$ 4.72
Effect of potential dilutive securities:			
Shares assumed issued from the exercise of options to purchase common shares, net of treasury shares assumed purchased from the proceeds, at the average market price for the period		683	
Interest expense incurred, net of taxes, and shares issued related to the assumed conversion at $42.185 per share of the 2006 Notes (redeemed July 7, 2003)	2,106	1,391	
Diluted earnings per share	$ 297,213	64,612	$ 4.60
Antidilutive securities:			
Shares assumed not issued from options to purchase common shares as the exercise prices are above the average market price for the period or the effect of the assumed exercise would be antidilutive	$	467	$ 41.87

(a) Represents income before cumulative effect of change in accounting principle.

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	For the Year Ended December 31, 2002		
	Income	Shares	Per Share
Basic earnings per share	$ 107,031	57,963	$ 1.85
Effect of potential dilutive securities:			
Shares assumed issued from the exercise of options to purchase common shares, net of treasury shares assumed purchased from the proceeds, at the average market price for the period		980	
Interest expense incurred, net of taxes, and shares issued related to the assumed conversion at $42.185 per share of the 2006 Notes	4,111	2,726	
Minority interest expense incurred, net of taxes, and shares issued related to the assumed conversion at $23.75 per share of the Trust Preferred Securities (redeemed June 3, 2002)	2,661	2,652	
Diluted earnings per share	$ 113,803	64,321	$ 1.77
Antidilutive securities:			
Shares assumed not issued from options to purchase common shares as the exercise prices are above the average market price for the period or the effect of the assumed exercise would be antidilutive	$	143	$ 38.00

	For the Year Ended December 31, 2001		
	Income	Shares	Per Share
Basic earnings per share	$ 87,954	51,031	$ 1.72
Effect of potential dilutive securities:			

	For the Year Ended December 31, 2001		
Shares assumed issued from the exercise of options to purchase common shares, net of treasury shares assumed purchased from the proceeds, at the average market price for the period		749	
Interest expense incurred, net of taxes, and shares issued related to the assumed conversion at $42.185 per share of the 2006 Notes	4,111	2,726	
Minority interest expense incurred, net of taxes, and shares issued related to the assumed conversion at $23.75 per share of the Trust Preferred Securities	6,338	6,316	
Diluted earnings per share	$ 98,403	60,822	$ 1.62
Antidilutive securities:			
Shares assumed not issued from options to purchase common shares as the exercise prices are above the average market price for the period or the effect of the assumed exercise would be antidilutive	$	266	$ 33.75

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(3) Income Taxes

The components of income before income taxes and cumulative effect of change in accounting principle for each of the three years in the period ended December 31, 2003, are as follows (expressed in thousands):

	2003	2002	2001
United States	$ 364,097	$ 101,349	$ 81,619
Foreign	151,132	103,462	67,948
Income before income taxes and cumulative effect of change in accounting principle	$ 515,229	$ 204,811	$ 149,567

The components of income tax expense (benefit) for each of the three years in the period ended December 31, 2003, are as follows (expressed in thousands):

	2003	2002	2001
Current			
United States	$ 116,813	$ 15,497	$
Foreign	51,491	11,351	10,996
Deferred			
United States	26,375	32,451	59,823
Foreign	25,443	38,481	(9,206)
Income tax expense	$ 220,122	$ 97,780	$ 61,613

Total income tax expense for each of the three years in the period ended December 31, 2003, differs from the amounts computed by applying the statutory federal income tax rate to income before taxes as follows (expressed as percent of pretax income):

	2003	2002	2001
Federal statutory income tax rate	35.0%	35.0%	35.0%
Increases (reductions) resulting from:			

	2003	2002	2001
Foreign income taxed at different rates	4.6	7.8	11.3
Recognition of net operating loss carryforwards			(20.4)
U.S. taxes on repatriation of foreign earnings	1.9	2.3	5.7
State income taxes, net of federal benefits	0.7	0.5	4.0
Other	0.5	2.2	5.6
	42.7%	47.8%	41.2%

The principal components of the Company's deferred income tax assets and liabilities at December 31, 2003 and 2002 (expressed in thousands) are as follows:

	December 31,	
	2003	2002
Deferred tax assets:		
Foreign deferred tax assets and net operating loss carry forwards	$ 2,795	$ 22,700
Valuation allowance of foreign deferred tax assets and net operating loss	(379)	(243)
Tax basis in excess of book basis for price hedge contracts		8,895
Other	9,938	3,654
	12,354	35,006
Deferred tax liabilities:		
Book basis in excess of tax basis for oil and gas properties and equipment	(553,967)	(538,132)
Other	(8,004)	(6,638)
	(561,971)	(544,770)
Net deferred tax liability	$ (549,617)	$ (509,764)

Book basis in excess of tax basis for oil and gas properties and equipment primarily results from differing methodologies for recording property costs and depreciation, depletion and amortization under United States generally accepted accounting principles and income tax reporting. In addition, the Company recorded a deferred tax liability resulting from book and tax basis differences of the acquired NORIC net assets (see Note 12).

During 2003, the Company utilized its remaining Thailand net operating loss carryforwards to offset current year income taxes. As of December 31, 2003 the Company had $8,300,000 in net operating loss carryforwards available to offset future income tax in Hungary. Such net operating loss carryforwards do not expire.

Where the Company's present intention is to reinvest the unremitted earnings in its foreign operations, the Company does not provide for U.S. income taxes on unremitted earnings of foreign subsidiaries. Unremitted earnings of foreign subsidiaries for which U.S. income taxes have not been provided are approximately $128,825,000 at December 31, 2003. It is not practicable to determine the amount of U.S. income taxes that would be payable upon remittance of the assets that represent those earnings.

During the third quarter of 2001, the Company reevaluated its global tax and cash position, including estimates regarding the realization of its Thailand operating loss carryforwards as well as its ability to indefinitely reinvest all unremitted foreign earnings in its foreign operations. Based on the Company's expectations for its Thailand operations, the Company determined it to be more likely than not that its remaining Thailand operating loss carryforwards would be realized and, therefore, reversed the remaining valuation allowance accordingly. In addition, the Company provided for U.S. income taxes on the unremitted earnings from a portion of its Thailand operations determined to be subject to repatriation. However, where the Company's continued intention is to reinvest the unremitted earnings of a foreign subsidiary in foreign operations, the Company will continue to not provide U.S. income taxes on those earnings.

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(4) Long-Term Debt

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

	December 31,	
	2003	2002
Senior debt		
Bank revolving credit agreement:		
LIBOR based loans, borrowings at December 31, 2003 and 2002 at interest rates of 2.3125% and 2.5625%, respectively	$ 135,000	$ 135,000
Swing line money market loans, borrowings at December 31, 2003 at an interest rate of 2.375%	4,000	
Banker's Acceptance loans, borrowings at December 31, 2002 at an interest rate of 2.2765% (terminated on April 11, 2003)		24,987
Total senior debt	139,000	159,987
Subordinated debt		
$10^3/_8$% Senior subordinated notes, due 2009	150,000	150,000
$8^1/_4$% Senior subordinated notes, due 2011	200,000	200,000
$5^1/_2$% Convertible subordinated notes, due 2006 (redeemed July 7, 2003)		115,000
$8^3/_4$% Senior subordinated notes, due 2007 (redeemed August 6, 2003)		100,000
Total subordinated debt	350,000	565,000
Unamortized discount on 2009 Notes	(1,739)	(2,084)
Long-term debt	$ 487,261	$ 722,903

On March 8, 2001, the Company entered into the Credit Facility, a reserve based revolving credit facility. The Credit Facility provides for a $515,000,000 revolving credit facility until March 7, 2006. The amount that may be borrowed may not exceed a borrowing base which is determined semi-annually and is calculated based upon substantially all of the Company's proved oil and gas properties. The borrowing base is currently established at $800,000,000. The Credit Facility is governed by various financial and other covenants, including requirements to maintain positive working capital (excluding current maturities of debt) and a fixed charge coverage ratio, and limitations on the creation of liens, commodity hedging above specified limits, the prepayment of subordinated debt, the payment of dividends, mergers and consolidations, investments and asset dispositions. In addition, the Company is prohibited from pledging borrowing base properties as security for other debt. The Company has pledged the stock of North Central and its inter-company receivables with North Central as collateral for its obligations under the Credit Facility. The Credit Facility also permits short-term swing-line loans and the issuance of up to $50,000,000 in letters of credit as part of the facility. Borrowings under the Credit Facility bear interest, at the Company's option, at a base (prime) rate plus a variable margin (currently none) or LIBOR plus a variable margin (currently l.125%). The margin varies as a function of the percentage of the borrowing base utilized and, with respect to the LIBOR rate, the Company's credit rating. A commitment fee on the unborrowed amount that is currently available under the Credit Facility is also charged based on the percentage of the borrowing base that is being utilized.

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On January 15, 1999, the Company issued $150,000,000 principal amount of 2009 Notes. The 2009 Notes bear interest at a rate of $10^{3}/_{8}$%, payable semi-annually in arrears on February 15 and August 15 of each year. The 2009 Notes are generally unsecured senior subordinated obligations of the Company, are subordinated in right of payment to the Company's senior indebtedness, which currently includes the Company's obligations under the Credit Facility, and are equal in right of payment to the 2011 Notes. The Company, at its option, may redeem the 2009 Notes in whole or in part, at any time on or after February 15, 2004, at a redemption price of 105.188% of their principal value and decreasing percentages thereafter. The indenture governing the 2009 Notes also imposes certain covenants on the Company that are substantially identical to the covenants contained in the indenture governing the 2011 Notes, described below.

On April 10, 2001, the Company issued $200,000,000 principal amount of 2011 Notes. The 2011 Notes bear interest at a rate of $8^{1}/_{4}$%, payable semi-annually in arrears on April 15 and October 15 of each year. The 2011 Notes are general unsecured senior subordinated obligations of the Company, are subordinated in right of payment to the Company's senior indebtedness, which currently includes the Company's obligations under the Credit Facility, and are equal in right of payment to the 2009 Notes. The Company, at its option, may redeem the 2011 Notes in whole or in part, at any time on or after April 15, 2006, at a redemption price of 104.125% of their principal value and decreasing percentages thereafter. The indentures governing the 2011 Notes also impose certain covenants on the Company including covenants limiting: incurrence of indebtedness including senior indebtedness; restricted payments; the issuance and sales of restricted subsidiary capital stock; transactions with affiliates; liens; disposition of proceeds of assets sales; non-guarantor restricted subsidiaries; dividends and other payment restrictions affecting restricted subsidiaries; and merger, consolidations and the sale of assets. As of December 31, 2003, $338,121,000 was available for dividends under this limitation, which is currently the Company's most restrictive covenant.

The Company gave notice on June 6, 2003 of its intent to redeem all $115,000,000 of its $5^{1}/_{2}$% Convertible Subordinated Notes due 2006 (the "2006 Notes") at 101.65% of their face amount. Prior to the redemption date of July 7, 2003, holders of $42,536,000 face value of the 2006 Notes converted their notes into 1,008,299 shares of the Company's common stock at the $42.185 per share conversion price. In connection with the redemption, the Company paid a total of $73,661,000 in cash to former holders of the 2006 Notes. The cash redemption payment was funded through a combination of available cash and borrowings under the Company's Credit Facility. The Company recorded a pre-tax loss on the redemption of the 2006 Notes of $1.8 million in "Loss on debt extinguishment" during the year ended December 31, 2003.

The Company also gave notice on July 7, 2003 of its intent to redeem all $100,000,000 of its $8^{3}/_{4}$% Senior Subordinated Notes due 2007 (the "2007 Notes") at 102.917% of their face amount. On August 6, 2003, the Company paid $102,917,000 in cash to holders of the 2007 Notes. The cash redemption payment was funded through a combination of available cash and borrowings under the Company's existing bank credit facility. The Company recorded a pre-tax loss on the redemption of the 2007 Notes of $4.1 million in "Loss on debt extinguishment" during the year ended December 31, 2003.

The Company currently has no maturities or sinking fund requirements during the next three years in connection with the above long-term debt. In 2006, maturities of $139,000,000 will become due consisting of the senior debt currently outstanding. The Company is currently in compliance with all debt covenants.

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(5) Commitments and Contingencies

The Company has commitments for operating leases (primarily for office space) in Houston, Midland, Fort Worth, Bangkok, Budapest, for an FPSO and FSO in the Gulf of Thailand, and for other equipment (including gas compressors). Rental expense for office space was $2,942,000 in 2003, $2,821,000 in 2002, and $2,623,000 in 2001. Expenses for the FPSO lease were approximately $10,600,000 in each of the years 2003, 2002 and 2001. Expenses for the FSO were approximately $4,000,000 in each of the years 2003, 2002 and 2001. Rental expense for other equipment was $4,241,000 in 2003, $2,022,000 in 2002 and $654,000 in 2001.

Future minimum lease payments related to the Company's operating leases at December 31, 2003 are approximately $22,300,000 in 2004; $22,000,000 in 2005; $21,900,000 in 2006; $18,800,000 in 2007; $15,300,000 in 2008 and $44,000,000 thereafter. Where rented equipment such as compressors is considered essential to the operation of the lease, the Company has assumed that such equipment will be leased for the estimated productive life of the reserves, even if the contract terminates prior to such date.

(6) Geographic Information

The Company's reportable geographic information is identified below. The accounting policies of the geographic regions are the same as those described in the summary of significant accounting policies (Note 1). The Company evaluates performance based on operating income (loss). Financial information by geographic region is presented below:

	2003	2002	2001
	(Expressed in thousands)		
Long-Lived Assets:			
As of December 31,			
United States	$ 1,943,564	$ 1,780,431	$ 1,748,046
Kingdom of Thailand	420,856	378,260	342,411
Other	11,421	358	271
Total	$ 2,375,841	$ 2,159,049	$ 2,090,728
Capital Expenditures: (including interest capitalized)			
For the year ended December 31,			
United States	$ 376,430	$ 269,250	$ 1,458,549
Kingdom of Thailand	132,409	112,440	73,192
Other	11,485		3,071
Total	$ 520,324	$ 381,690	$ 1,534,812
Revenues:			
For the year ended December 31,			
United States	$ 858,505	$ 542,014	$ 422,120
Kingdom of Thailand	303,470	212,763	183,074
Other	21	77	4,923
Total	$ 1,161,996	$ 754,854	$ 610,117
Depreciation, depletion, and amortization expense:			
For the year ended December 31,			
United States	$ 237,853	$ 221,646	$ 142,643
Kingdom of Thailand	87,906	66,099	61,814
Other	61	64	2,152
Total	$ 325,820	$ 287,809	$ 206,609
Operating income (loss):			
For the year ended December 31,			
United States	$ 399,678	$ 138,934	$ 113,976
Kingdom of Thailand	151,830	103,021	76,493
Other	(3,779)	(1,782)	(10,588)
Total	$ 547,729	$ 240,173	$ 179,881

(7) Sales to Major Customers

The Company is an oil and gas exploration and production company that generally sells its oil and gas to numerous customers on a month-to-month basis. For purposes of comparison, sales have been presented for all three years for those customers who have exceeded 10% of revenues in any given year (expressed in thousands):

	2003	2002	2001
China Intl. United Petroleum and Chemical Co. Ltd.	$ 119,444	$ 55,140	$ 13,665
Enron Corp. and affiliates	827	5,594	96,970

(8) Credit Risk

Substantially all of the Company's accounts receivable at December 31, 2003 and 2002, result from oil and gas sales and joint interest billings to other companies in the energy industry. This concentration of customers and joint interest owners may impact the Company's overall credit risk, either positively or negatively, in that these entities may be similarly affected by industry-wide changes in economic or other conditions. Such receivables are generally not collateralized. As of December 31, 2003 and 2002, the Company had provided reserves for receivables from customers and joint interest owners that are considered doubtful of collection of $3,810,000 and $5,542,000, respectively.

A substantial portion of the Company's oil and gas operations are conducted in Southeast Asia, and a substantial portion of its natural gas and liquids hydrocarbon production are sold there. Southeast Asia in general, and the Kingdom of Thailand in particular, experienced severe economic difficulties in 1997 and 1998 which were characterized by sharply reduced economic activity, illiquidity, highly volatile foreign currency exchange rates and unstable stock markets. Since that time, the economic situation in the Kingdom of Thailand has generally stabilized and begun to improve. However, as with most emerging market economies, the Thai economy remains particularly sensitive to worldwide economic trends. The economic health of the Thai economy and its effect on the volatility of the Thai Baht against the U.S. dollar will continue to have a material impact on the Company's operations in the Kingdom of Thailand, as well as the prices that the company receives for its natural gas production there.

As a result of the substantial oil and gas operations and earnings from its Thailand operations, the Company generates a significant amount of cash which is maintained in various bank accounts with multi-national banks for future foreign investment. These balances are diversified between cash and short-term investments.

(9) Employee Benefit Plans

The Company has a tax-advantaged savings plan in which all U.S. salaried employees may participate. Under such plan, a participating employee may allocate up to 30% of their salary, up to a maximum allowed by law, and the Company will then match the employee's contribution on a dollar for dollar basis up to the lesser of 6% of the employee's salary or $12,000 in 2003. Funds contributed by the employee and the matching funds contributed by the Company are held in trust by a bank trustee in six separate funds. Amounts contributed and earnings and accretions thereon may be used to purchase shares of the Company's common stock, invest in a money market fund or invest in four stock, bond, or blended stock and bond mutual funds according to instructions from the employee. The Company contributed $1,233,000 to the savings plan in 2003, $1,068,000 in 2002, and $928,000 in 2001.

The Company has adopted a trusteed retirement plan for its U.S. salaried employees. The benefits are based on years of service and the employee's average compensation for five consecutive years within the

final ten years of service which produce the highest average compensation. The Company makes annual contributions to the plan in the amount of retirement plan cost accrued or the maximum amount that can be deducted for federal income tax purposes. The Company does not expect to make a contribution to the plan in 2004. The plan's investment strategy and goals are to ensure, over the long-term life of the retirement plan, an adequate pool of sufficiently liquid assets to support the benefit obligations to participants, retirees and beneficiaries. Investment objectives are long-term in nature covering typical market cycles of three to five years.

Although the Company has no obligation to do so, the Company currently provides full medical benefits to its retired U.S. employees and dependents. For current employees, the Company assumes all or a portion of post-retirement medical and term life insurance costs based on the employee's age and length of service with the Company. The post-retirement medical plan has no assets and is currently funded by the Company on a pay-as-you-go basis. The expected Company contributions to the post-retirement medical plan during 2004 are approximately $556,000.

The following table sets forth the plans' status (in thousands of dollars) as of December 31, 2003 and 2002. The Company uses a December 31 measurement date for its plans.

	Retirement Plan		Post-Retirement Medical Plan	
	2003	2002	2003	2002
Change in benefit obligation				
Benefit obligation at beginning of year	$ 24,297	$ 19,020	$ 15,067	$ 9,904
Service cost	2,248	1,929	1,102	736
Interest cost	1,546	1,395	915	715
Plan amendments		348		
Benefits paid	(340)	(704)	(338)	(358)
Actuarial loss	1,768	2,309	399	4,070
Benefit obligation at end of year	$ 29,519	$ 24,297	$ 17,145	$ 15,067
Change in plan assets				
Fair value of plan assets at beginning of year	$ 26,625	$ 33,465	$	$
Actual return on plan assets	6,234	(5,721)		
Employer contributions			338	358
Benefits paid	(340)	(704)	(338)	(358)
Administrative expenses	(283)	(416)		
Fair value of plan assets at end of year	$ 32,236	$ 26,624	$	$
Reconciliation of funded status				
Funded status	$ 2,717	$ 2,327	$ (17,145)	$ (15,067)
Unrecognized actuarial loss	9,037	12,085	3,292	2,957
Unrecognized transition (asset) or obligation			608	913
Unrecognized prior service cost	671	714		
Prepaid (accrued) benefit cost at year-end	$ 12,425	$ 15,126	$ (13,245)	$ (11,197)
Components of net periodic benefit cost				
Service cost	$ 2,248	$ 1,929	$ 1,102	$ 736
Interest cost	1,546	1,395	915	715
Expected return on plan assets	(2,176)	(3,116)		
Amortization of prior service cost	43	6		
Amortization of transition (asset) obligation			305	305
Amortization of net loss	1,040		64	
	$ 2,701	$ 214	$ 2,386	$ 1,756
Accumulated benefit obligation	$ 23,591	$ 19,273		

Plan Assumptions

	Retirement Plan			Post-Retirement Medical Plan		
	2003	2002	2001	2003	2002	2001
Plan assumptions to determine benefit obligations						
Discount rate	6.00%	6.50%	7.25%	6.00%	6.50%	7.25%
Rate of compensation increase	4.75%	4.75%	4.75%			
Plan assumptions to determine net cost						
Discount rate	6.50%	7.25%	7.50%	6.50%	7.25%	7.50%
Expected long-term rate of return on plan assets	8.50%	9.50%	9.50%			
Rate of compensation increase	4.75%	4.75%	4.75%			

To develop the expected long-term rate of return on plan assets assumption, the Company considered the current level of expected returns on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the target asset allocation to develop the expected long-term rate of return on plan assets assumption for the portfolio. This resulted in the selection of the 8.50% assumption for 2003.

The following table provides the target and actual asset allocations in the retirement plan:

		Actual as of December 31,	
Asset Category	Target	2003	2002
Equity securities	100%	100%	99%
Debt securities	0%	0%	0%
Real estate	0%	0%	0%
Other	0%	0%	1%
Total	100%	100%	100%

For measurement purposes related to the Company's post-retirement medical plan, a 12% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2004. The rate is assumed to decrease gradually to 5% for 2012 and remain at that level thereafter. This compares to the amounts used for 2003 measurement purposes, where a 13% annual rate of increase in the per capita cost of covered health care benefits was assumed, decreasing gradually to 5% for 2012 and remaining level thereafter.

Assumed health care cost trends have a significant effect on the amount reported for the health care plan. A one-percentage-point change in assumed health care cost trend rates would have the following effects (in thousands):

	One Percentage Point	
	Increase	Decrease
Effect on total of service and interest cost components for 2003	$ 387	$ (310)
Effect on year-end 2003 postretirement benefit obligation	$ 2,838	$ (2,305)

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In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) became law. The Act introduces a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare. Pursuant to guidance recently published by the FASB, the Company has elected to defer recognizing the effects of the Act in the accounting for and disclosure of our postretirement medical plan until authoritative guidance on the accounting for the federal subsidy is issued. Accordingly, the disclosures of the accumulated postretirement benefit obligation and the net periodic postretirement benefit cost included herein do not reflect the effects of the Act on the postretirement medical plan. Authoritative guidance on accounting for the federal subsidy is pending and that guidance, when issued, could require the Company to change previously reported information. The Company does not believe however that the effects of the Act will have a material effect on its financial condition or results of operations.

(10) Stock-Based Compensation Plans

The Company's incentive plans authorize awards granted wholly or partly in common stock (including rights or options which may be exercised for or settled in common stock) to key employees and non-employee directors. Awards to employees of the Company may be made as grants of stock options, stock appreciation rights, stock awards, cash awards, performance awards or any combination thereof (collectively, "Awards"). Employee Awards generally become exercisable in three installments. The number of shares available for future issuance was 2,297,657, 2,911,565 and 898,520 as of December 31, 2003, 2002 and 2001, respectively. Stock options granted in 2003 expire 5 years from the date of grant, if not exercised. Stock options granted prior to 2003, if not exercised, expire 10 years from the date of grant.

Restricted Stock

The Company granted the following shares of restricted stock during the indicated periods:

Year Ended December 31,	Number of Awards		Weighted Average Grant Date Fair Value
2003	144,000	$	6,045,840
2002	40,065	$	1,192,935
2001	41,102	$	1,018,097

The number of unvested shares of restricted stock was 157,019, 38,621 and 39,394 as of December 31, 2003, 2002 and 2001, respectively.

Stock Options

A summary of the status of the Company's stock option activity as of December 31, 2003, 2002 and 2001, and changes during the years ended on those dates is presented below:

	Number of Awards		Weighted Average Exercise Price
Outstanding, December 31, 2000	3,401,854	$	20.46
Granted in 2001	1,035,400	$	25.35
Exercised in 2001	(377,764)	$	17.30
Canceled in 2001	(206,910)	$	21.75
Outstanding, December 31, 2001	3,852,580	$	22.01
Exercisable, December 31, 2001	2,267,561	$	21.09
Weighted-average fair value of options granted during 2001		$	11.98
Outstanding, December 31, 2001	3,852,580	$	22.01

	Number of Awards	Weighted Average Exercise Price
Granted in 2002	960,900	$ 29.84
Exercised in 2002	(1,022,034)	$ 19.72
Canceled in 2002	(44,000)	$ 23.49
Outstanding, December 31, 2002	3,747,446	$ 24.62
Exercisable, December 31, 2002	1,992,883	$ 22.41
Weighted-average fair value of options granted during 2002		$ 12.43
Outstanding, December 31, 2002	3,747,446	$ 24.54
Granted in 2003	403,000	$ 42.02
Exercised in 2003	(1,553,573)	$ 21.48
Canceled in 2003	(14,100)	$ 17.14
Outstanding, December 31, 2003	2,582,773	$ 29.16
Exercisable, December 31, 2003	1,258,999	$ 25.75
Weighted-average fair value of options granted during 2003		$ 9.61

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The following table summarizes information about stock options outstanding at December 31, 2003:

	Options Outstanding			Options Exercisable	
Range of Option Prices	Number Outstanding	Weighted Average Remaining Contractual Life (days)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$17.91 to $19.56	71,700	1,912	$ 18.60	71,700	$ 18.60
$20.31 to $24.77	1,024,569	2,457	$ 23.27	739,233	$ 22.71
$25.38 to $29.78	923,504	3,069	$ 29.62	291,399	$ 29.35
$31.18 to $33.94	56,000	2,473	$ 32.09	52,667	$ 32.06
$36.00	40,000	885	$ 36.00	40,000	$ 36.00
$40.63 to $43.46	467,000	3,193	$ 41.87	64,000	$ 40.92
Total	2,582,773	2,769	$ 29.16	1,258,999	$ 25.75

(11) Change in Accounting Principle

The Company adopted Statement of Financial Accounting Standard ("SFAS") No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"), as of January 1, 2003. SFAS 143 requires the Company to record the fair value of a liability for an asset retirement obligation ("ARO") in the period in which it is incurred. Upon adoption of SFAS 143, the Company was required to recognize a liability for the present value of all legal obligations associated with the retirement of tangible long-lived assets and an asset retirement cost ("ARC") was capitalized as part of the carrying value of the associated asset. Upon initial application of SFAS 143, a cumulative effect of a change in accounting principle was also required in order to recognize a liability for any existing AROs adjusted for cumulative accretion, an increase to the carrying amount of the associated long-lived asset and accumulated depreciation on the capitalized cost. Subsequent to initial measurement, liabilities are required to be accreted to their present value each period and capitalized costs are depreciated over the estimated useful life of the related assets. This periodic accretion expense is recorded as "Transportation and other" in the consolidated statement of income. Upon settlement of the liability, the Company will settle the obligation against its recorded amount and will record any resulting gain or loss.

Activity related to the Company's ARO during the year ended December 31, 2003 is as follows (in thousands):

	Year Ended December 31, 2003
Initial ARO as of January 1, 2003	$ 63,643
Liabilities incurred during period	3,001
Liabilities settled during period	(691)
Accretion expense	4,837
Balance of ARO as of December 31, 2003	$ 70,790

For the year ended December 31, 2003, the Company recognized depreciation expense related to its ARC of $3,850,000. As a result of the adoption of SFAS 143 on January 1, 2003, the Company recorded a $56,769,000 increase in the net capitalized cost of its oil and gas properties and recognized an after-tax

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charge of $4,166,000 for the cumulative effect of the change in accounting principle (net of related income tax benefit of $2,707,000).

Had the Company adopted SFAS 143 on January 1, 2002, the pro forma ARO would have been $58,187,000. Had SFAS 143 been applied retroactively during the years ended December 31, 2002 and 2001, the Company's net income and earnings per share would have been as follows (expressed in thousands, except per share amounts):

	Year Ended December 31, 2002		Year Ended December 31, 2001	
	As Reported	Pro forma	As Reported	Pro forma
Net Income	$ 107,031	$ 106,662	$ 87,954	$ 85,873
Earnings per share:				
Basic	$ 1.85	$ 1.84	$ 1.72	$ 1.68
Diluted	$ 1.77	$ 1.76	$ 1.62	$ 1.58

(12) Acquisition

On March 14, 2001, the merger of the Company and NORIC was consummated. As a result of the merger, the Company acquired all of the outstanding capital stock of North Central which was the principal asset of NORIC. North Central was an independent domestic oil and gas exploration and production company. The merger was accounted for using the purchase method of accounting. Accordingly, the purchase price was allocated to the net assets acquired based on their estimated fair values at the date of acquisition. Commencing March 14, 2001, North Central's operations were consolidated with the operations of the Company. Pursuant to the merger agreement among the Company and NORIC and certain former NORIC shareholders, the former shareholders received 12,615,816 shares of the Company's common stock and approximately $344,711,000 in cash. In addition, at the closing all the $78,600,000 principal amount of North Central's existing bank debt was repaid.

The following summary presents unaudited pro forma consolidated results of operations as if the acquisition had occurred at the beginning of the period presented. The pro forma results are for illustrative purposes only and include adjustments in addition to the pre-acquisition historical results of North Central, such as increased depreciation, depletion and amortization expense resulting from the allocation of fair value to oil and gas properties acquired and increased interest expense on acquisition debt. The unaudited pro forma information (presented in thousands of dollars, except per share amounts) is not

necessarily indicative of the operating results that would have occurred had the acquisition been consummated at that date, nor are they necessarily indicative of future operating results.

		Year Ended December 31, 2001
Revenues	$	668,480
Income before cumulative effect of change in accounting principle	$	104,348
Net income	$	104,348
Earnings per share:		
Basic		
Income before cumulative effect of change in accounting principle	$	1.95
Net income	$	1.95
Diluted		
Income before cumulative effect of change in accounting principle	$	1.81
Net income	$	1.81

(13) Minority Interest

Pogo Trust I, a subsidiary of the Company, called for redemption its $6^{1}/_{2}$% Cumulative Quarterly Income Convertible Preferred Securities due 2029 (the "Trust Preferred Securities") on June 3, 2002. Prior to their redemption, holders of 2,997,196 of the 3,000,000 outstanding Trust Preferred Securities converted their Trust Preferred Securities, representing $149,850,000 face value of Trust Preferred Securities, into 6,309,972 shares of the Company's common stock. In connection with the redemption, Pogo Trust I paid a total of $147,000 to former holders of the Trust Preferred Securities. Subsequent to June 3, 2002, there were no Trust Preferred Securities outstanding.

The amounts recorded under "Minority Interests Dividends and costs associated with mandatorily redeemable preferred securities of a subsidiary trust" principally reflect cumulative dividends and, to a lesser extent, the amortization of issuance expenses related to the offering and sale of the Trust Preferred Securities.

(14) Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value.

Cash and Cash Equivalents

Fair value is carrying value.

Receivables and Payables

Fair value is approximately carrying value.

Derivative Financial Instruments

Fair value is carrying value.

Debt and Other

Instrument	Basis of Fair Value Estimate
Bank revolving credit agreement	Fair value is carrying value as of December 31, 2003 and 2002 based on the market value interest rates.
Banker's acceptance loans	Fair value is carrying value as of December 31, 2002 based on the market value interest rates.
2007 Notes	Fair value is 104.3% of carrying value as of December 31, 2002, based on quoted market values. This instrument was redeemed by the Company on August 6, 2003.
2009 Notes	Fair value is 106% and 108% of carrying value as of December 31, 2003 and 2002, respectively, based on quoted market values.
2011 Notes	Fair value is 110.6% and 105% of carrying value as of December 31, 2003 and 2002, based on quoted market value.
2006 Notes	Fair value is 106.7% of carrying value as of December 31, 2002, based on quoted market values. This instrument was redeemed by the Company on July 7, 2003.

The carrying value and estimated fair value of the Company's financial instruments at December 31, 2003 and 2002 (in thousands of dollars) are as follows:

	2003		2002	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents	$ 178,754	$ 178,754	$ 134,449	$ 134,449
Receivables	$ 156,467	$ 156,467	$ 116,441	$ 116,441
Payables	$ (148,942)	$ (148,942)	$ (125,592)	$ (125,592)
Debt:				
Bank revolving credit agreement loans	$ (139,000)	$ (139,000)	$ (135,000)	$ (135,000)
Banker's acceptance loans	$	$	$ (24,987)	$ (24,987)
2007 Notes	$	$	$ (100,000)	$ (104,250)
2009 Notes	$ (148,261)	$ (159,000)	$ (147,916)	$ (162,000)
2011 Notes	$ (200,000)	$ (221,250)	$ (200,000)	$ (210,000)
2006 Notes	$	$	$ (115,000)	$ (122,711)

The Company occasionally enters into hedging contracts to minimize the impact of oil and gas price fluctuations. See Note 15 for a further discussion of these contracts.

(15) Hedging Activities

During 2003, the Company recognized a pre-tax loss of $22,822,000 ($14,873,000 after tax) from its price hedge contracts which are included in oil and gas revenues. During 2002 and 2001, the Company recognized pre-tax gains of $3,640,000 ($2,367,000 after tax) and $14,592,000 ($9,485,000 after tax), respectively, from its price hedge contracts which are included in oil and gas revenues. As of December 31, 2003, the Company held no derivative instruments.

UNAUDITED SUPPLEMENTARY FINANCIAL DATA

Oil and Gas Producing Activities

The results of operations from oil and gas producing activities exclude non-oil and gas revenues, general and administrative expenses, other non oil and gas producing expenses, interest charges, interest income and interest capitalized. Income tax (expense) or benefit was determined by applying the statutory rates to pretax operating results with adjustments for permanent differences.

	Total Company	United States	Kingdom of Thailand	Other International
	(Expressed in thousands)			
	2003			
Revenues	$ 1,159,544	$ 856,074	$ 303,470	$
Lease operating expense	(123,098)	(81,731)	(41,367)	
Exploration expense	(7,547)	(6,899)	(644)	(4)(a)
Dry hole and impairment expense	(35,102)	(31,600)	(3,231)	(271)(a)
Depreciation, depletion and amortization expense	(321,572)	(234,579)	(86,993)	
Production and other taxes	(35,485)	(23,735)	(11,750)	
Transportation and accretion	(17,952)	(16,949)	(1,003)	
Pretax operating results	618,788	460,581	158,482	(275)
Income tax (expense) benefit	(256,198)	(176,957)	(79,241)	
Operating results	$ 362,590	$ 283,624	$ 79,241	$ (275)
	2002			
Revenues	$ 750,401	$ 537,717	$ 212,684	$
Lease operating expense	(112,663)	(74,416)	(38,247)	
Exploration expense	(4,783)	(4,161)	(544)	(78)(a)
Dry hole and impairment expense	(26,999)	(26,999)		
Depreciation, depletion and amortization expense	(283,865)	(218,636)	(65,229)	
Production and other taxes	(20,058)	(20,058)		
Transportation	(10,194)	(10,194)		
Pretax operating results	291,839	183,253	108,664	(78)
Income tax (expense) benefit	(128,498)	(65,545)	(62,967)	14
Operating results	$ 163,341	$ 117,708	$ 45,697	$ (64)
	2001			
Revenues	$ 596,077	$ 408,514	$ 183,005	$ 4,558
Lease operating expense	(92,693)	(54,452)	(36,993)	(1,248)
Exploration expense	(23,373)	(11,877)	(2,162)	(9,334)(b)
Dry hole and impairment expense	(26,945)	(26,136)		(809)
Depreciation, depletion and amortization expense	(203,676)	(140,304)	(61,243)	(2,129)
Production and other taxes	(22,007)	(22,007)		
Transportation	(3,457)	(3,457)		
Pretax operating results	223,926	150,281	82,607	(8,962)

	Total Company	United States	Kingdom of Thailand	Other International
Income tax (expense) benefit	(96,590)	(52,598)	(46,322)	2,330
Operating results	$ 127,336	$ 97,683	$ 36,285	$ (6,632)

(a) Included in Other International for 2003 and 2002 are costs associated with activities related almost entirely to Hungary with the exception of $271 of dry hole and impairment expense related to the Company's British North Sea block that was relinquished in 2003.

(b) Included in the expensed exploration cost reflected in Other International for 2001 are seismic costs associated with Hungary ($8,734) and Canada ($600). All other pretax operating items are related to Canada. The Company's Canadian operations were sold in 2001.

The following table sets forth the Company's costs incurred (expressed in thousands) for oil and gas producing activities during the years indicated.

	Total Company	United States	Kingdom of Thailand	Other International(a)
Costs incurred (capitalized unless otherwise indicated):				
2003:				
Property acquisition				
Proved	$ 177,680	$ 177,680	$	$
Unproved	15,540	12,065	3,475	
Exploration				
Capitalized	59,714	42,248	6,155	11,311
Expensed	7,547	6,899	644	4
Development	248,348	131,732	116,616	
Asset retirement cost(b)	59,142	49,706	9,436	
Interest	16,531	10,194	6,163	174
Total oil and gas costs incurred	$ 584,502	$ 430,524	$ 142,489	$ 11,489
Provision for depreciation, depletion and amortization	$ 321,572	$ 234,579	$ 86,993	$
2002:				
Property acquisition				
Proved	$	$	$	$
Unproved	8,030	8,030		
Exploration				
Capitalized	43,165	40,028	3,137	
Expensed	4,783	4,161	544	78
Development	303,197	205,035	98,162	
Interest	24,033	12,892	11,141	

	Total Company	United States	Kingdom of Thailand	Other International(a)
Total oil and gas costs incurred	$ 383,208	$ 270,146	$ 112,984	$ 78
Provision for depreciation, depletion and amortization	$ 283,865	$ 218,636	$ 65,229	$
2001:				
Property acquisition				
Proved	$ 949,704	$ 949,673	$	$ 31
Unproved	172,947	172,947		
Exploration				
Capitalized	59,390	48,290	9,180	1,920
Expensed	23,373	11,877	2,162	9,334
Development	314,736	255,800	57,816	1,120
Interest	33,242	27,046	6,196	
Total oil and gas costs incurred	$ 1,553,392	$ 1,465,633	$ 75,354	$ 12,405
Provision for depreciation, depletion and amortization	$ 203,676	$ 140,304	$ 61,243	$ 2,129

(a) Included in Other International for the years 2003 and 2002 are costs associated with initial activities related almost entirely to Hungary. For 2001, the costs are associated primarily with the Company's Canadian operations, with the exception of $8,734 of expensed exploration costs related to Hungary. The Company sold its Canadian operations in 2001.

(b) Includes $56,769 of cumulative asset retirement cost recorded to adopt the provisions of SFAS 143 on January 1,2003. Of these costs $47,893 has been reflected as activity in the United States and $8,876 has been reflected as activity in the Kingdom of Thailand.

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The following information regarding estimates of the Company's proved oil and gas reserves, which are located offshore in United States waters of the Gulf of Mexico, onshore in the United States, offshore in the Kingdom of Thailand and in Hungary is based on reports prepared by Ryder Scott Company, L.P. and Miller & Lents, Ltd. The definitions and assumptions that serve as the basis for the discussions under the caption "Item 1, Business Exploration and Production Data Reserves" should be referred to in connection with the following information.

Estimates of Proved Reserves

Oil, Condensate and Natural Gas Liquids (Bbls.)

	Total Company	United States	Kingdom of Thailand	Other International
Proved Reserves as of December 31, 2000	95,321,497	57,478,436	37,065,285	777,776
Revisions of previous estimates	8,694,016	3,521,490	5,172,457	69
Extensions, discoveries and other additions	18,278,228	15,818,428	2,459,800	
Purchase of properties	10,115,300	10,115,300		
Sale of properties	(1,556,413)	(837,413)		(719,000)

	Total Company	United States	Kingdom of Thailand	Other International
Estimated 2001 production	(11,573,233)	(6,117,546)	(5,396,842)	(58,845)
Proved Reserves as of December 31, 2001	119,279,395	79,978,695	39,300,700	
Revisions of previous estimates	9,563,087	9,290,517	272,570	
Extensions, discoveries and other additions	8,460,885	3,965,585	4,495,300	
Sale of properties	(202,785)	(202,785)		
Estimated 2002 production	(18,921,750)	(12,939,750)	(5,982,000)	
Proved Reserves as of December 31, 2002	118,178,832	80,092,262	38,086,570	
Revisions of previous estimates	9,964,506	6,338,668	3,625,838	
Extensions, discoveries and other additions	6,305,471	2,982,400	3,312,627	10,444
Purchase of properties	4,301,200	4,301,200		
Estimated 2003 production	(23,880,000)	(16,162,000)	(7,718,000)	
Proved Reserves as of December 31, 2003	114,870,009	77,552,530	37,307,035	10,444
Proved Developed Reserves as of:				
December 31, 2000	60,656,634	35,132,295	24,746,563	777,776
December 31, 2001	79,777,300	59,383,200	20,394,100	
December 31, 2002	97,873,000	74,041,149	23,831,851	
December 31, 2003	87,269,277	67,391,031	19,878,246	

Estimates of Proved Reserves

Natural Gas (MMcf)

	Total Company	United States	Kingdom of Thailand	Other International
Proved Reserves as of December 31, 2000	369,983	214,621	153,304	2,058
Revisions of previous estimates	11,749	(743)	12,492	
Extensions, discoveries and other additions	63,519	57,344	6,175	
Purchase of properties	468,776	468,776		
Sale of properties	(8,477)	(6,949)		(1,528)
Estimated 2001 production	(86,758)	(62,482)	(23,746)	(530)
Proved Reserves as of December 31, 2001	818,792	670,567	148,225	
Revisions of previous estimates	66,796	38,237	28,559	
Extensions, discoveries and other additions	89,774	78,575	11,199	
Estimated 2002 production	(101,852)	(73,473)	(28,379)	
Proved Reserves as of December 31, 2002	873,510	713,906	159,604	
Revisions of previous estimates	22,408	5,686	16,722	
Extensions, discoveries and other additions	95,664	65,095	20,438	10,131
Purchase of properties	129,119	129,119		
Estimated 2003 production	(108,378)	(76,802)	(31,576)	

	Total Company	United States	Kingdom of Thailand	Other International
Proved Reserves as of December 31, 2003	1,012,323	837,004	165,188	10,131
Proved Developed Reserves as of:				
December 31, 2000	239,978	150,684	87,236	2,058
December 31, 2001	602,345	532,348	69,997	
December 31, 2002	687,556	600,255	87,301	
December 31, 2003	780,774	702,836	77,938	

POGO PRODUCING COMPANY & SUBSIDIARIES

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATED TO PROVED OIL AND GAS RESERVES Unaudited

The standardized measure of discounted future net cash flows from the production of proved reserves is developed as follows:

1. Estimates are made of quantities of proved reserves and the future periods in which they are expected to be produced based on year-end economic conditions.

2. The estimated future gross revenues from proved reserves are priced on the basis of year-end market prices, except in those instances where fixed and determinable natural gas price escalations are covered by contracts.

3. The future gross revenue streams are reduced by estimated future costs to develop and to produce the proved reserves, as well as certain abandonment costs based on year-end cost estimates, and the estimated effect of future income taxes. These cost estimates are subject to some uncertainty.

The standardized measure of discounted future net cash flows does not purport to present the fair value of the Company's oil and gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves in excess of proved reserves, anticipated future changes in prices and costs, a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The following are the principal sources of change in the standardized measure of discounted future net cash flows. All amounts are related to changes in reserves located in the United States, the Kingdom of Thailand, Hungary, and Canada, as noted.

	Year Ended December 31, 2003			
	Total Company	United States	Kingdom of Thailand	Hungary
	(Expressed in thousands)			
Beginning balance	$ 2,055,215	$ 1,714,788	$ 340,427	$
Revisions to prior years' proved reserves:				
Net changes in prices and production costs	619,394	434,060	185,334	
Net changes due to revisions in quantity estimates	200,593	113,329	87,264	
Net changes in estimates of future development costs	(212,465)	(105,717)	(106,748)	
Accretion of discount	485,277	406,857	78,420	
Changes in production rate and other	(369,708)	(339,473)	(30,235)	

	Year Ended December 31, 2003			
Total revisions	723,091	509,056	214,035	
New field discoveries and extensions, net of future production and development costs	320,188	241,946	61,726	16,516
Purchases of properties	289,484	289,484		
Sales of oil and gas produced, net of production costs	(987,981)	(737,628)	(250,353)	
Previously estimated development costs incurred	246,863	130,247	116,616	
Net change in income taxes	(196,830)	(138,770)	(58,012)	(48)
Net change in standardized measure of discounted future net cash flows	394,815	294,335	84,012	16,468
Ending balance	$ 2,450,030	$ 2,009,123	$ 424,439	$ 16,468

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	Year Ended December 31, 2002		
	Total Company	United States	Kingdom of Thailand
	(Expressed in thousands)		
Beginning balance	$ 1,138,048	$ 826,570	$ 311,478
Revisions to prior years' proved reserves:			
Net changes in prices and production costs	1,285,867	1,096,580	189,287
Net changes due to revisions in quantity estimates	255,617	202,952	52,665
Net changes in estimates of future development costs	(183,597)	(97,784)	(85,813)
Accretion of discount	240,283	189,055	51,228
Changes in production rate and other	(69,640)	(15,695)	(53,945)
Total revisions	1,528,530	1,375,108	153,422
New field discoveries and extensions, net of future production and development costs	334,335	218,991	115,344
Sales of properties	(2,344)	(2,344)	
Sales of oil and gas produced, net of production costs	(607,486)	(433,049)	(174,437)
Previously estimated development costs incurred	304,661	206,499	98,162
Net change in income taxes	(640,529)	(476,987)	(163,542)
Net change in standardized measure of discounted future net cash flows	917,167	888,218	28,949
Ending balance	$ 2,055,215	$ 1,714,788	$ 340,427

	Year Ended December 31, 2001			
	Total Company	United States	Kingdom of Thailand	Canada
	(Expressed in thousands)			
Beginning balance	$ 1,715,176	$ 1,327,734	$ 370,630	$ 16,812
Revisions to prior years' proved reserves:				
Net changes in prices and production costs	(1,184,494)	(1,083,561)	(100,933)	

	Year Ended December 31, 2001			
Net changes due to revisions in quantity estimates	85,497	32,533	53,016	(52)
Net changes in estimates of future development costs	(149,719)	(120,496)	(28,784)	(439)
Accretion of discount	245,492	192,555	50,602	2,335
Changes in production rate and other	19,636	19,571	(4,666)	4,731
Total revisions	(983,588)	(959,398)	(30,765)	6,575
New field discoveries and extensions, net of future production and development costs	166,518	126,429	40,089	
Purchases of properties	345,728	345,728		
Sales of properties	(93,384)	(65,787)		(27,597)
Sales of oil and gas produced, net of production costs	(477,970)	(328,648)	(146,012)	(3,310)
Previously estimated development costs incurred	128,440	86,484	40,974	982
Net change in income taxes	337,128	294,028	36,562	6,538
Net change in standardized measure of discounted future net cash flows	(577,128)	(501,164)	(59,152)	(16,812)
Ending balance	$ 1,138,048	$ 826,570	$ 311,478	$

	Total Company	United States	Kingdom of Thailand	Hungary
	(Expressed in thousands)			
	2003			
Future gross revenues	$ 8,507,228	$ 6,912,547	$ 1,545,580	$ 49,101
Future production costs:				
Lease operating expense	(1,811,584)	(1,417,118)	(385,058)	(9,408)
Future development and abandonment costs	(520,159)	(324,813)	(181,396)	(13,950)
Future net cash flows before income taxes	6,175,485	5,170,616	979,126	25,743
Discount at 10% per annum	(2,485,484)	(2,241,953)	(234,304)	(9,227)
Discounted future net cash flows before income taxes	3,690,001	2,928,663	744,822	16,516
Future income taxes, net of discount at 10% per annum	(1,239,971)	(919,540)	(320,383)	(48)
Standardized measure of discounted future net cash flows related to proved oil and gas reserves	$ 2,450,030	$ 2,009,123	$ 424,439	$ 16,468
	2002			
Future gross revenues	$ 7,078,353	$ 5,486,454	$ 1,591,899	$
Future production costs:				
Lease operating expense	(1,819,485)	(1,150,305)	(669,180)	
Future development and abandonment costs	(406,101)	(267,578)	(138,523)	
Future net cash flows before income taxes	4,852,767	4,068,571	784,196	

	Total Company		United States		Kingdom of Thailand		Hungary
Discount at 10% per annum		(1,754,411)		(1,573,013)		(181,398)	
Discounted future net cash flows before income taxes		3,098,356		2,495,558		602,798	
Future income taxes, net of discount at 10% per annum		(1,043,141)		(780,770)		(262,371)	
Standardized measure of discounted future net cash flows related to proved oil and gas reserves	$	2,055,215	$	1,714,788	$	340,427	$

	2001						
Future gross revenues	$	4,202,888	$	3,115,416	$	1,087,472	$
Future production costs:							
Lease operating expense		(1,354,815)		(899,262)		(455,553)	
Future development and abandonment costs		(445,239)		(325,600)		(119,639)	
Future net cash flows before income taxes		2,402,834		1,890,554		512,280	
Discount at 10% per annum		(862,174)		(760,201)		(101,973)	
Discounted future net cash flows before income taxes		1,540,660		1,130,353		410,307	
Future income taxes, net of discount at 10% per annum		(402,612)		(303,783)		(98,829)	
Standardized measure of discounted future net cash flows related to proved oil and gas reserves	$	1,138,048	$	826,570	$	311,478	$

Quarterly Results Unaudited

Summaries of the Company's results of operations by quarter for the years 2003 and 2002 are as follows:

	Quarter Ended							
	Mar. 31		June 30		Sept. 30		Dec. 31	
	(Expressed in thousands, except per share amounts)							
2003								
Revenues	$	312,673	$	297,146	$	279,332	$	272,845
Gross profit(a)	$	181,206	$	158,970	$	148,682	$	120,162
Net income	$	88,477	$	79,719	$	67,660	$	55,085
Earnings per share(b):								
Basic	$	1.45	$	1.29	$	1.07	$	0.87
Diluted	$	1.37	$	1.24	$	1.06	$	0.86
2002								
Revenues	$	143,016	$	184,546	$	209,165	$	218,127
Gross profit(a)	$	40,821	$	71,006	$	86,040	$	91,795
Net income	$	9,025	$	28,618	$	31,637	$	37,751

	Quarter Ended			
Earnings per share(b):				
Basic	$ 0.17	$ 0.51	$ 0.52	$ 0.62
Diluted	$ 0.17	$ 0.48	$ 0.51	$ 0.60

(a) Represents revenues less lease operating, production and other taxes, transportation and other, exploration, dry hole, and impairment, and depreciation, depletion and amortization expenses.

(b) The sum of the individual quarterly earnings (loss) per share may not agree with year-to-date earnings (loss) per share as each quarterly computation is based on the income or loss for that quarter and the weighted average number of common shares outstanding during that period.

ITEM 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure.

Information regarding a change in accountants was previously reported on a Form 8-K dated April 17, 2002.

ITEM 9A. Controls and Procedures

The Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chairman, President and Chief Executive Officer and its Senior Vice President and Chief Financial Officer, of the effectiveness of the Company's disclosure controls and procedures pursuant to Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended, as of the end of the period covered by this quarterly report. Based upon that evaluation, the Company's Chairman, President and Chief Executive Officer and its Senior Vice President and Chief Financial Officer concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information required to be included in our periodic Securities and Exchange Commission filings.

There were no changes in the Company's internal control over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART III

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

The information responsive to Items 401, 405 and 406 of Regulation S-K in the Company's definitive Proxy Statement for its annual meeting to be held on April 27, 2004, to be filed within 120 days of December 31, 2003 pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended (the Company's "2004 Proxy Statement"), is incorporated herein by reference. See also Item S-K 401(b) appearing in Part I of this Form 10-K.

ITEM 11. ***Executive Compensation.***

The information responsive to Item 402 of Regulation S-K in the Company's 2004 Proxy Statement is incorporated herein by reference. The portion of the incorporated material consisting of the Compensation Committee Report on Executive Compensation and the Performance Graph is not be considered "filed" with the Commission.

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

The information responsive to Items 201(d) and 403 of Regulation S-K in the Company's 2004 Proxy Statement is incorporated herein by reference.

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

The information responsive to Item 404 of Regulation S-K in the Company's 2003 Proxy Statement is incorporated herein by reference.

ITEM 14. ***Principal Accountant Fees and Services.***

The information responsive to Item 9(e) of Schedule 14A in the Company's 2004 Proxy Statement is incorporated herein by reference.

PART IV

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

(a) Financial Statements and Supplementary Data, Financial Statement Schedules and Exhibits

1. **Financial Statements and Supplementary Data:**

2. **Financial Statement Schedules:**

All Financial Statement Schedules have been omitted because they are not required, are not applicable or the information required has been included elsewhere herein.

3. Exhibits:

*3.1 Restated Certificate of Incorporation of Pogo Producing Company (Exhibit 3(a), Annual Report on Form 10-K for the year ended December 31, 1997, File No. 1-7792).

*3.2 Amendment to Amended and Restated Certificate of Incorporation of Pogo Producing Company (Exhibit 4.3, Registration Statement on Form S-3, filed May 11, 2001, File No. 333-60800).

*3.3 Certificate of Designations of Series A Junior Participating Preferred Stock of Pogo Producing Company, dated April 26, 1994 (Exhibit 4(d), Registration Statement on Form S-8, filed August 9, 1994, File No. 33-54969).

*3.4 Bylaws of Pogo Producing Company, as amended and restated through July 16, 2002 (Exhibit 4.1, Quarterly Report on Form 10-Q for the quarter ended June 30, 2002, File No. 1-7792).

*4.1 Credit Agreement dated as of March 8, 2001 among Pogo Producing Company, as the Borrower, certain commercial lending institutions, as the Lenders, Bank of Montreal as Administrative Agent, Toronto Dominion (Texas), Inc., as Syndication Agent, BNP Paribas, as Documentation Agent and Bank of America, N.A. and Fleet National Bank, as Managing Agents (Exhibit 4.4, Current Report on Form 8-K filed March 26, 2001, File No. 1-7792).

*4.2 Indenture dated as of January 15,1999, between Pogo Producing Company and State Street Bank & Trust Company as Trustee (Exhibit 4.2, Registration Statement on Form S-4, filed February 10, 1999, File No. 333-72129).

*4.3 Indenture dated as of April 10, 2001, between Pogo Producing Company and Wells Fargo Bank Minnesota, National Association, as Trustee (Exhibit 4.2, Registration Statement on Form S-4, filed April 24, 2001, File No. 333-59426).

*4.4 Rights Agreement dated as of April 26, 1994, between Pogo Producing Company and Harris Trust Company of New York, as Rights Agent (Exhibit 4, Current Report on Form 8-K filed, April 26, 1994, File No. 1-7792). Other instruments defining the rights of holders of long-term debt of Pogo Producing Company and its subsidiaries are not being filed because the total amount of securities authorized by such instruments does not exceed 10% of the total assets of Pogo Producing Company and its subsidiaries on a consolidated basis as of December 31, 2003. Pogo Producing Company hereby agrees to furnish to the Commission a copy of any such debt instrument upon request.

Executive Compensation Plans and Arrangements (comprising Exhibits 10.1 through 10.33, inclusive)

*10.1 1989 Incentive and Nonqualified Stock Option Plan of Pogo Producing Company, as amended and restated effective January 25, 1994 (Exhibit 99, Definitive Proxy Statement on Schedule 14A, filed March 22, 1994, File No. 1-7792).

*10.2 Form of Stock Option Agreement under 1989 Incentive and Nonqualified Stock Option Plan, as amended and restated effective January 22, 1991 (Exhibit 10(d)(1), Annual Report on Form 10-K for the year ended December 31, 1991, File No. 0-5468).

*10.3 Form of Director Stock Option Agreement under 1989 Incentive and Nonqualified Stock Option Plan as amended and restated effective January 22, 1991 (Exhibit 10(d)(2), Annual Report on Form 10-K for the year ended December 31, 1991, File No. 0-5468).

*10.4 1995 Long-Term Incentive Plan (Exhibit 4(c), Registration Statement on Form S-8 filed May 22, 1996, File No. 333-04233).

*10.5 1998 Incentive Plan (Exhibit 4.7, Registration Statement on Form S-8 filed August 15, 2002, File No. 333-98205).

*10.6 2000 Incentive Plan (Exhibit B to the Company's Definitive Proxy Statement filed on Schedule 14A, March 27, 2000, File No. 001-7792).

*10.7 2002 Incentive Plan (Exhibit B to the Company's Definitive Proxy Statement filed on Schedule 14A, March 25, 2002, File No. 001-7792).

*10.8 Executive Employment Agreement by and between Pogo Producing Company and Paul G. Van Wagenen, dated February 1, 2003 (Exhibit 10.12, Annual Report on Form 10-K for the year ended December 31, 2002, File No. 1-7792).

10.9 Extension Agreement to Executive Employment Agreement between Paul G. Van Wagenen and Pogo Producing Company, dated effective February 1, 2003

*10.10 Executive Employment Agreement by and between Pogo Producing Company and Stephen R. Brunner, dated as of February 1, 2003 (Exhibit 10.15, Annual Report on Form 10-K for the year ended December 31, 2002, File No. 1-7792).

10.11 Extension Agreement to Executive Employment Agreement between Stephen R. Brunner and Pogo Producing Company, dated effective February 1, 2003.

*10.12 Executive Employment Agreement by and between Pogo Producing Company and Stuart P. Burbach, dated February 1, 2003 (Exhibit 10.8, Annual Report on Form 10-K for the year ended December 31, 2002, File No. 1-7792).

10.13 Extension Agreement to Executive Employment Agreement between Stuart P. Burbach and Pogo Producing Company, dated effective February 1, 2003.

*10.14 Executive Employment Agreement by and between Pogo Producing Company and Jerry A. Cooper, dated February 1, 2003 (Exhibit 10.9, Annual Report on Form 10-K for the year ended December 31, 2002, File No. 1-7792).

10.15	Extension Agreement to Executive Employment Agreement between Jerry A. Cooper and Pogo Producing Company, dated effective February 1, 2003
*10.16	Executive Employment Agreement by and between Pogo Producing Company and John O. McCoy, Jr., dated February 1, 2003 (Exhibit 10.11, Annual Report on Form 10-K for the year ended December 31, 2002, File No. 1-7792).
10.17	Extension Agreement to Executive Employment Agreement between John O. McCoy, Jr. and Pogo Producing Company, dated effective February 1, 2003
*10.18	Executive Employment Agreement by and between Pogo Producing Company and David R. Beathard, dated as of February 1, 2003 (Exhibit 10.14, Annual Report on Form 10-K for the year ended December 31, 2002, File No. 1-7792).
10.19	Extension Agreement to Executive Employment Agreement between David R. Beathard and Pogo Producing Company, dated effective February 1, 2003
*10.20	Executive Employment Agreement by and between Pogo Producing Company and Radford P. Laney, dated February 1, 2003 (Exhibit 10.10, Annual Report on Form 10-K for the year ended December 31, 2002, File No. 1-7792).
10.21	Extension Agreement to Executive Employment Agreement between Radford P. Laney and Pogo Producing Company, dated effective February 1, 2003.
*10.22	Executive Employment Agreement by and between Pogo Producing Company and J. Don McGregor, dated as of February 1, 2003 (Exhibit 10.16, Annual Report on Form 10-K for the year ended December 31, 2002, File No. 1-7792).
10.23	Extension Agreement to Executive Employment Agreement between J. Don McGregor and Pogo Producing Company, dated effective February 1, 2003.
*10.24	Executive Employment Agreement by and between Pogo Producing Company and Gerald A. Morton, dated as of February 1, 2003 (Exhibit 10.17, Annual Report on Form 10-K for the year ended December 31, 2002, File No. 1-7792).
10.25	Extension Agreement to Executive Employment Agreement between Gerald A. Morton and Pogo Producing Company, dated effective February 1, 2003.
*10.26	Executive Employment Agreement by and between Pogo Producing Company and James P. Ulm, II, dated as of February 1, 2003 (Exhibit 10.18, Annual Report on Form 10-K for the year ended December 31, 2002, File No. 1-7792).
10.27	Extension Agreement to Executive Employment Agreement between James P. Ulm, II and Pogo Producing Company, dated effective February 1, 2003.
10.28	Executive Employment Agreement by and between Pogo Producing Company and Barry W. Acomb, dated February 1, 2004.
*10.29	Executive Employment Agreement by and between Pogo Producing Company and Bruce E. Archinal, dated as of February 1, 2003 (Exhibit 10.13, Annual Report on Form 10-K for the year ended December 31, 2002, File No. 1-7792).
10.30	Extension Agreement to Executive Employment Agreement between Bruce E. Archinal and Pogo Producing Company, dated effective February 1, 2003.
10.31	Executive Employment Agreement by and between Pogo Producing Company and Michael J. Killelea, dated February 1, 2004.
*10.32	Form of Restricted Stock Award Agreement Under Incentive Plans (Exhibit 10.1, Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, File No. 1-7792)

*10.33	Form of Directors Phantom Stock Agreement (Exhibit 10.2, Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, File No. 1-7792)
*10.34	Amended and Restated Bareboat Charter Agreement by and between Tantawan Services, L.L.C. and Tantawan Production B.V., dated as of February 9,1996 (Exhibit 10.26, Annual Report on Form 10-K for the year ended December 31, 1999, File No. 001-7792).
*10.35	Bareboat Charter Agreement by and between Thaipo Limited, Thai Romo Limited, Palang Sophon Limited, B8/32 Partners Limited and Watertight Shipping B.V. dated as of August 24, 1998 (Exhibit 10.27, Annual Report on Form 10-K for the year ended December 31, 1999, File No. 001-7792).
*10.36	Gas Sales Agreement dated November 7, 1995, among The Petroleum Authority of Thailand, Thaipo, Limited, Thai Romo Ltd. and The Sophonpanich Co., Ltd. (Exhibit 10(k), Quarterly Report on Form 10-Q for the quarter ended June 30, 1996, File No. 001-7792).
*10.37	The First Amendment to the Gas Sales Agreement dated November 12, 1997, among The Petroleum Authority of Thailand, B8/32 Partners Limited, Thaipo, Limited, Thai Romo Limited and Palang Sophon Limited (Exhibit 10(g)(ii), Annual Report on Form 10-K for the year ended December 31, 1998, File No. 001-7792).
*10.38	The Second Amendment to the Gas Sales Agreement dated effective as of October 1, 2001, among The Petroleum Authority of Thailand, Chevron Offshore (Thailand) Limited, Thaipo Limited, Palang Sophon Limited and B8/32 Partners Limited (Exhibit 10.23, Annual Report on Form 10-K for the year ended December 31, 2002, File No. 1-7792).
*10.39	The Third Amendment to the Gas Sales Agreement dated November 7, 1995 between PTT Public Company Limited and Chevron Offshore (Thailand) Limited, Thaipo Limited, Palang Sophon Limited and B8/32 Partners Limited, dated effective as of October 1,]2001 (Exhibit 10.1, Quarterly Report on Form 10-Q for the quarter ended September 30, 2003, File No. 1-7792).
21	List of Subsidiaries of Pogo Producing Company
23.1	Consent of Arthur Anderson LLP (omitted pursuant to Rule 437a of the Securities Act)
23.2	Consent of PricewaterhouseCoopers LLP
23.3	Consent of Ryder Scott Company, L.P.
23.4	Consent of Miller and Lents, Ltd.
24	Powers of Attorney from each director of Pogo Producing Company whose signature is affixed to this Form 10-K for year ended December 31, 2003.
31.1	Certification of Chief Executive Officer, pursuant to Rule 13a-14(a) under the Securities Exchange Act.
31.2	Certification of Chief Financial Officer, pursuant to Rule 13a-14(a) under the Securities Exchange Act.
32.1	Certification of Chief Executive Officer, pursuant to 18 U.S.C. Section 1350.
32.2	Certification of Chief Financial Officer, pursuant to 18 U.S.C. Section 1350
99.1	Summary Report of Ryder Scott Company, L.P.
99.2	Summary Report of Miller and Lents, Ltd.

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* Asterisk indicates exhibits incorporated by reference as shown.

(b) Reports on Form 8-K

Current Report on Form 8-K filed on October 14, 2003, regarding Items 7, 9 and 12. Furnished materials only; not filed for purposes of Section 18 of the Securities and Exchange Act.

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SIGNATURES

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

POGO PRODUCING COMPANY
(REGISTRANT)

BY: /S/ PAUL G. VAN WAGENEN

Paul G. Van Wagenen
Chairman, President and Chief Executive Officer

Date: February 24, 2004

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on February 24, 2004.

Signatures	Title
/S/ PAUL G. VAN WAGENEN **Paul G. Van Wagenen** *Chairman, President and Chief Executive Officer*	Principal Executive Officer and Director
/S/ JAMES P. ULM, II **James P. Ulm, II** *Senior Vice President and Chief Financial Officer*	Principal Financial Officer
/S/ THOMAS E. HART **Thomas E. Hart** *Vice President and Chief Accounting Officer*	Principal Accounting Officer
/S/ JERRY M. ARMSTRONG **Jerry M. Armstrong**	Director
/S/ ROBERT H. CAMPBELL **Robert H. Campbell**	Director
/S/ WILLIAM L. FISHER	Director

Signatures	Title
William L. Fisher	

/S/ GERRIT W. GONG **Gerrit W. Gong**	Director
/S/ CARROLL W. SUGGS **Carroll W. Suggs**	Director
/S/ STEPHEN A. WELLS **Stephen A. Wells**	Director
/S/ THOMAS E. HART **Thomas E. Hart** *Attorney-in-Fact*	