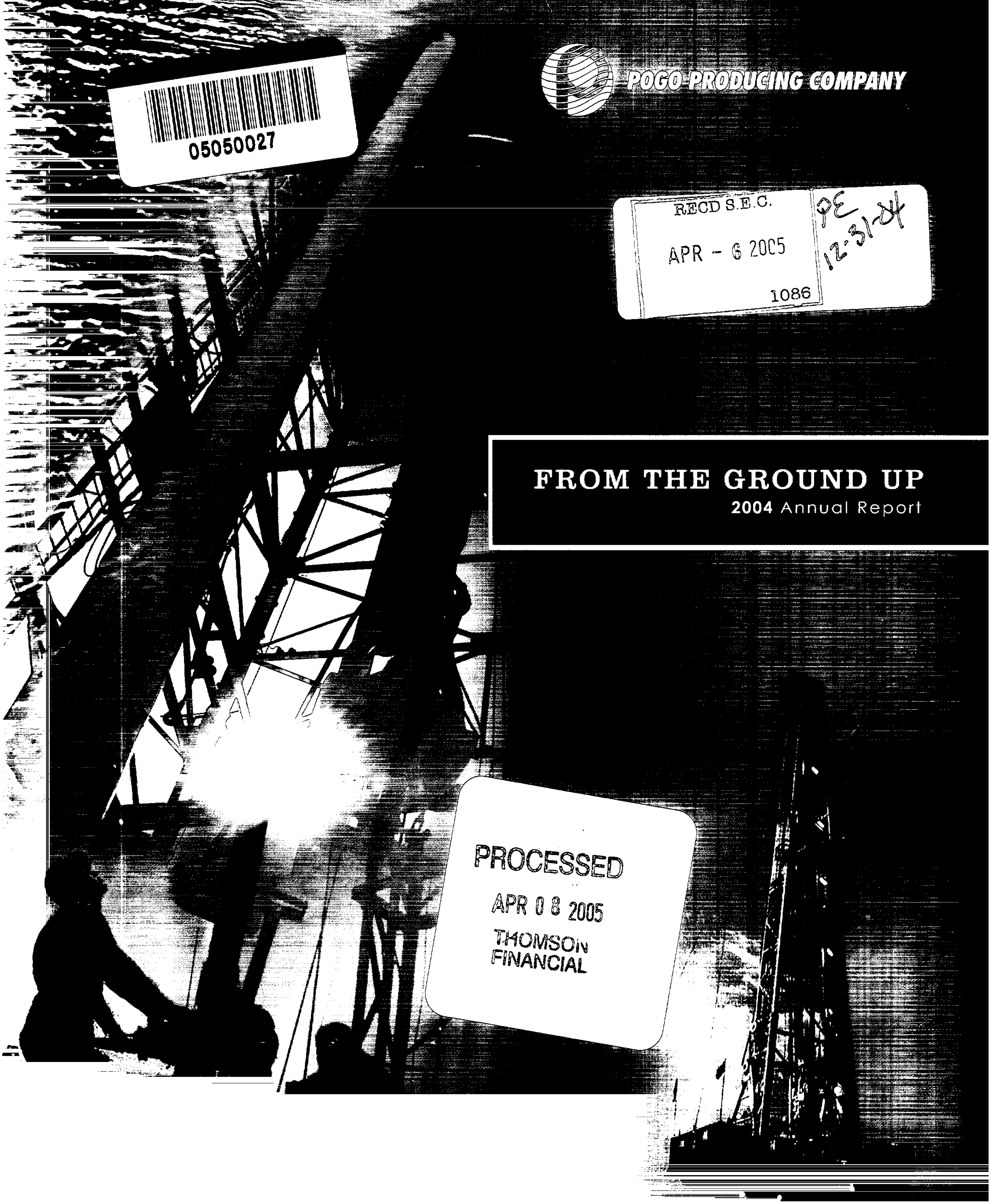
POGO PRODUCING COMPANY



FROM THE GROUND UP

2004 Annual Report

ABOUT THE COMPANY

Pogo Producing Company explores for, develops and produces oil and natural gas. Headquartered in Houston, Pogo owns interests in 90 federal and state Gulf of Mexico lease blocks offshore from Louisiana and Texas.

Pogo also owns approximately 705,000 gross leasehold acres in major onshore oil and gas basins of the United States, approximately 588,000 gross acres in the Gulf of Thailand, approximately 778,000 gross acres in Hungary and 1,044,000 gross acres in New Zealand. Pogo common stock is listed on the New York Stock Exchange and the Pacific Exchange under the symbol "PPP".

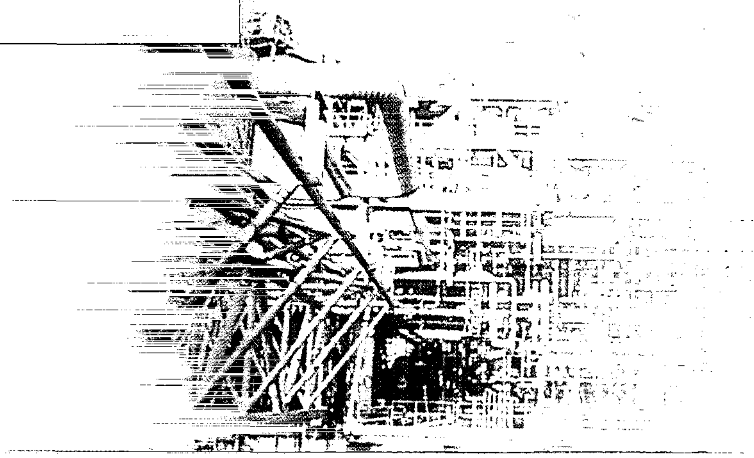
financial highlights

(expressed in thousands, except per share amounts)	2004	2003	2002	2001	2000
	Year Ended December 31,				
Income Statement:					
Total Revenues	$ 1,322,979	$1,161,996	$ 754,854	$ 610,117	$ 497,991
Net income	261,754	290,941	107,031	87,954	87,255
Net income per common share					
Basic	4.10	4.65	1.85	1.72	2.20
Diluted	4.06	4.54	1.77	1.62	1.99
Cash dividends per common share	0.2125	0.20	0.12	0.12	0.12
Balance Sheet:					
Total assets	$ 3,481,109	$2,758,651	$2,491,593	$2,423,979	$1,114,649
Long-term debt	755,000	487,261	722,903	792,561	365,000
Shareholders' equity	1,727,895	1,453,653	1,077,784	824,885	358,271
Weighted average number of					
common shares outstanding	63,848	62,538	57,963	51,031	40,445

operational highlights

	2004	2003	2002	2001	2000
Average Daily Production:					
Total Liquids (Bbls)	51,357	66,230	51,840	31,708	27,929
Natural Gas (Mcf)	324,000	297,000	279,000	237,800	164,600
Estimated Year-end Proved Reserves:					
Total Liquids (Mbbls)	116,383	114,870	118,179	119,279	95,321
Natural Gas (MMcf)	1,079,670	1,012,323	873,510	818,792	369,983
Total (MMcfe)	1,777,968	1,701,543	1,582,584	1,534,466	941,909
Percentage of Production Replaced:	**133%**	**147%**	**122%**	**480%**	**177%**

DEAR SHAREHOLDERS



Pogo achieved record highs in several important areas of its business in 2004:

- Annual revenues, up 14% from 2003, topped $1.32 billion.
- Natural gas production, 9% better than 2003, averaged 324 million cubic feet per day (mmcf/d).
- Discretionary cash flow, up 4% from 2003, reached $759 million.
- Year-end estimated proven reserves topped 1.77 trillion cubic feet equivalent (tcfe), up 4% from 2003.

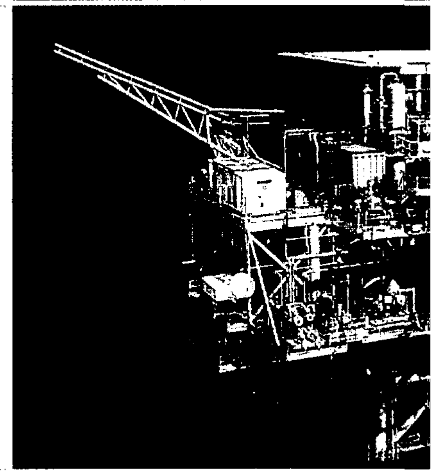
Pogo's 2004 results also reached near-record levels in other key areas, second only to Pogo's record-setting 2003 performance:

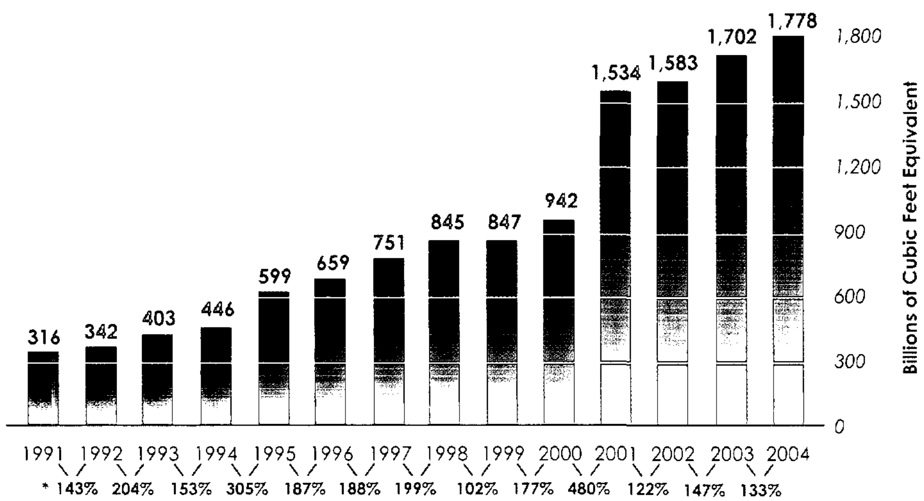
- Net income, 10% below 2003, totaled $261.8 million.
- Net cash from operating activities was down just 1% from 2003, at $738.7 million.
- Total energy production, including natural gas, crude oil, condensate and plant products, averaging 105,357 equivalent barrels per day, 9% below 2003, was Pogo's second best year ever.

RESERVES REACH RECORD LEVEL

One of the most important of Pogo's continuing goals is to grow its hydrocarbon reserves. Proven but still in the ground, oil and natural gas reserves measure the Company's true asset base, awaiting future development and production. Those hydrocarbons, when produced and sold, become the Company's future revenues, net income and cash flow.

Independent engineers evaluate Pogo's properties at the end of each year, estimating how many barrels of oil and cubic feet of natural gas are available for ready extraction.





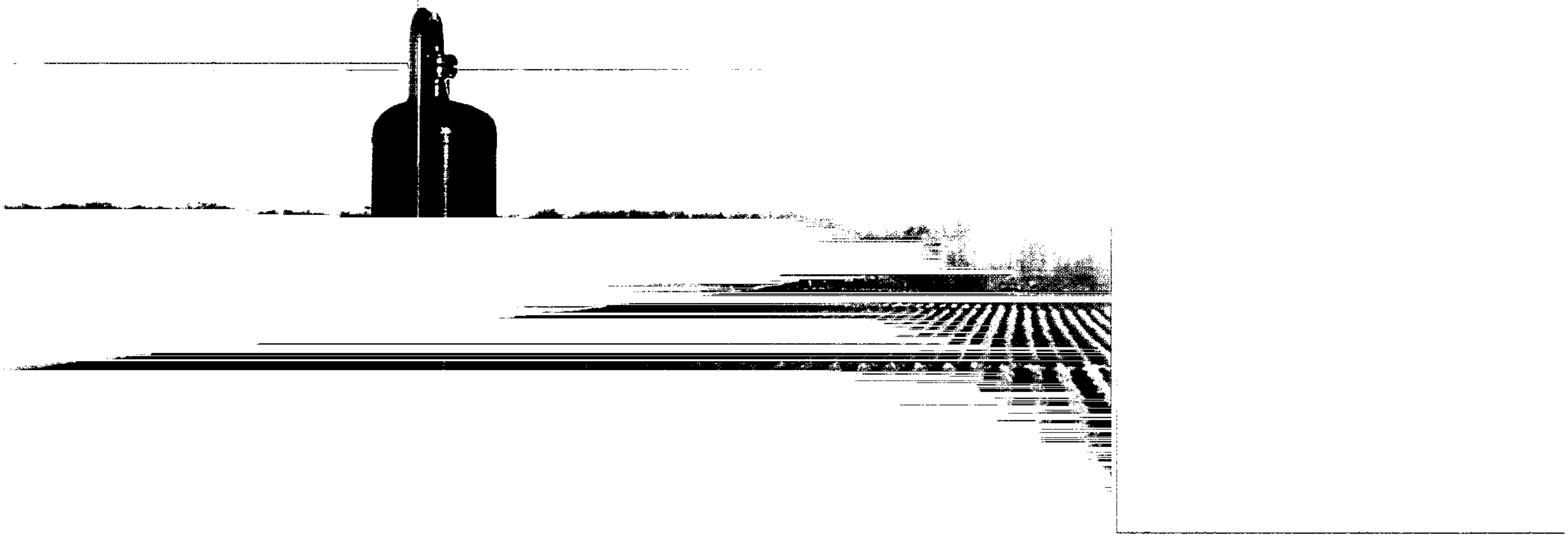
** Percentage replacement of yearly hydrocarbon production*
*** Ryder Scott Company and Miller & Lents year-end estimate of proven reserves*

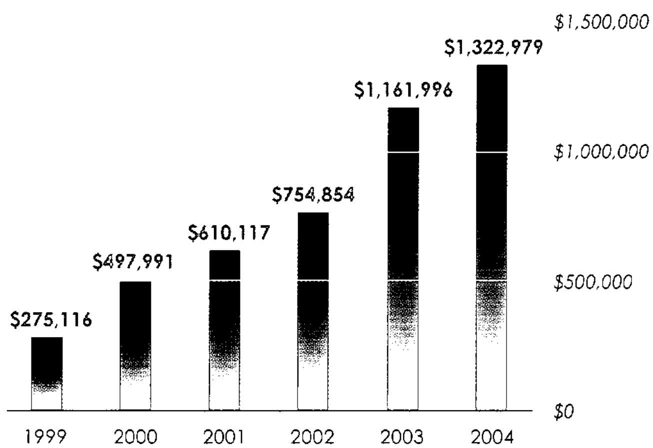
Figure A: Proven Reserves** At Year End

If an exploration company is doing well, its reserves should grow larger each year by successful drilling and property acquisitions.

Last year was the 13th successive year Pogo added more new reserves than it produced. Pogo produced an average of over 105,000 barrels of equivalent oil and natural gas each day, but replaced 133% of those hydrocarbons with new discoveries or acquisitions. By year-end, Pogo's proven reserves had reached 1.778 tcfe of natural gas, crude oil, condensate and plant products. **See Figure A.**

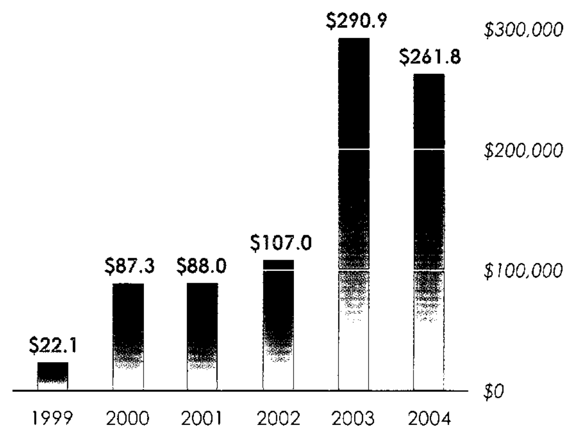
During 2004, Pogo's asset base grew 4% larger, rising from 1.702 tcfe to 1.778 tcfe. Expressed in natural gas equivalent units, Pogo produced some 232 billion cubic feet equivalent (bcfe) during 2004, while adding 308.5 bcfe of new reserves. Most of Pogo's reserves growth, 269 bcfe, came by way of domestic property acquisitions, at a price of $515 million, an average of $1.91 per thousand cubic feet equivalent (mcfe). Those new properties are located in many of Pogo's core operational areas: west and south Texas, the San Juan Basin of New Mexico, south Louisiana and the Gulf of Mexico outercontinental shelf (OCS).





Expressed in Thousands

Figure B: Total Revenue



Expressed in Thousands

Figure C: Net Income

PRICE HEDGING ACTIVITY

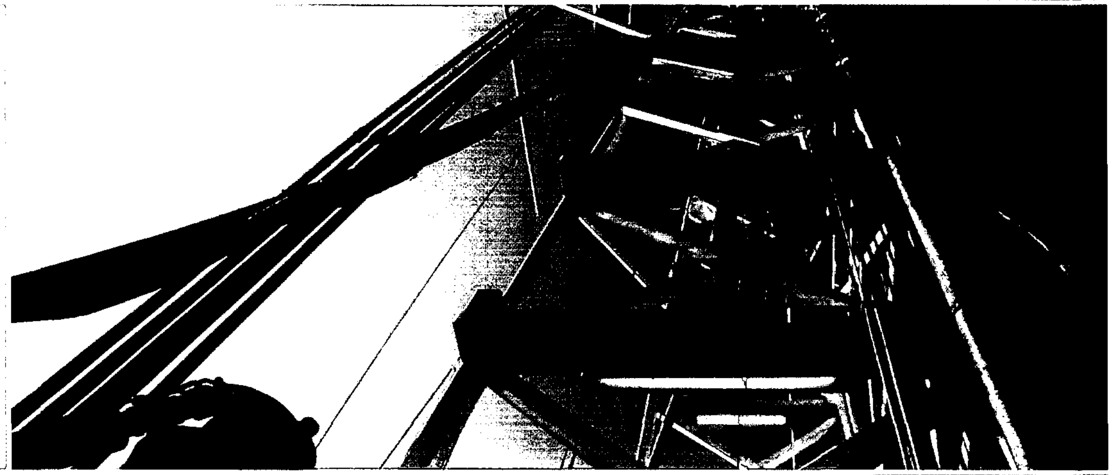
The 2004 acquisitions offer considerable future development potential. Moreover, Pogo locked in good near-term returns on current production volumes with costless price collars.

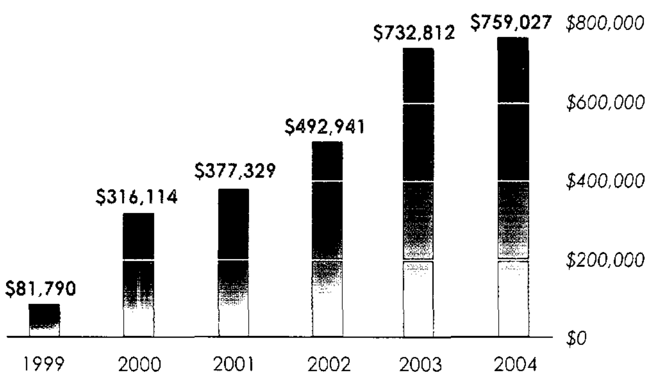
Pogo entered into natural gas collars on 35 mmcf/d with a floor of at least $5.50/mcf and a ceiling of up to $9.30/mcf in 2005, and a floor of at least $5.00/mcf and a ceiling of up to $8.27/mcf in 2006. Some 5,000 barrels per day of 2005 crude oil were also collared at a range of $40.00/barrel to $62.50/barrel.

REVENUE, INCOME AND CASH FLOW ALL POSITIVE

Strong production plus high energy prices yielded record 2004 revenues of more than $1.322 billion. Those revenues are almost 4.8 times the $275.1 million revenues recorded just five years ago. **See Figure B.**

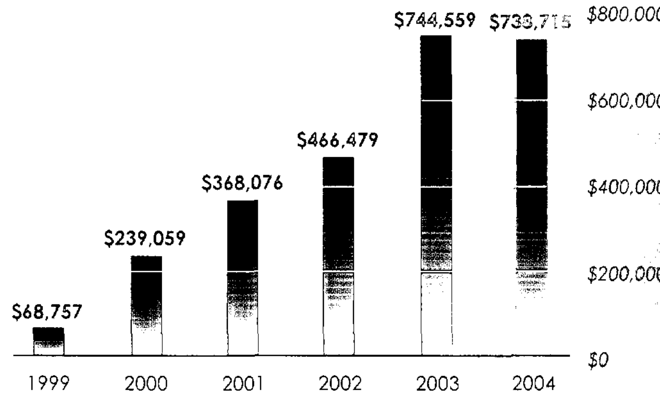
Although 10% below record 2003 net income, Pogo's 2004 income topped $261 million, far above most recent years. **See Figure C.**





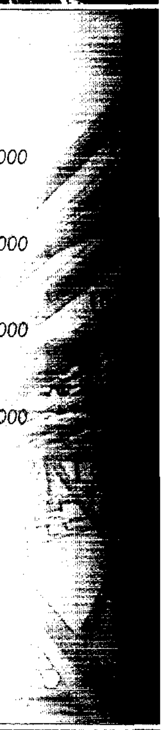
Expressed in Thousands

Figure D: Discretionary Cash Flow



Expressed in Thousands

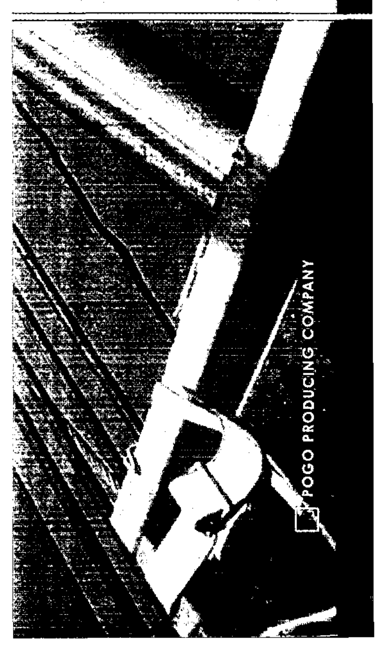
Figure E: Operating Cash Flow



Pogo's 2004 discretionary cash flow, a calculation of the money available for dividends, debt repayment and capital expenditures, reached a record of over $759 million. That is 4% higher than 2003, and double the discretionary cash flow generated as recently as 2001. **See Figure D.** Net cash generated from 2004 operating activities dipped about 1% from 2003, to $738.7 million, but was still double Pogo's 2001 net cash. **See Figure E.**

Pogo's strong balance sheet and impressive financial performance led the Company to declare a 25% increase in its common stock dividend in October, 2004. It was the second dividend increase in two years, having been raised 67% in January, 2003. Such dividend increases demonstrate Pogo's longstanding commitment to its shareholders, and evidence Pogo's ability to achieve and sustain fundamental economic growth.

In light of its continuing financial strength, Pogo announced in January of 2005, a plan to repurchase, in the open market or in privately negotiated transactions, not less than $275 million nor more than $375 million of Pogo's common stock. With Pogo's existing inventory of high-quality leases and the currently favorable climate for property acquisitions, Pogo believes that this stock buyback program could yield good returns at a time when attractive cash-flow multiples appear to be available to purchasers of Pogo's common stock. That repurchase program has now begun.



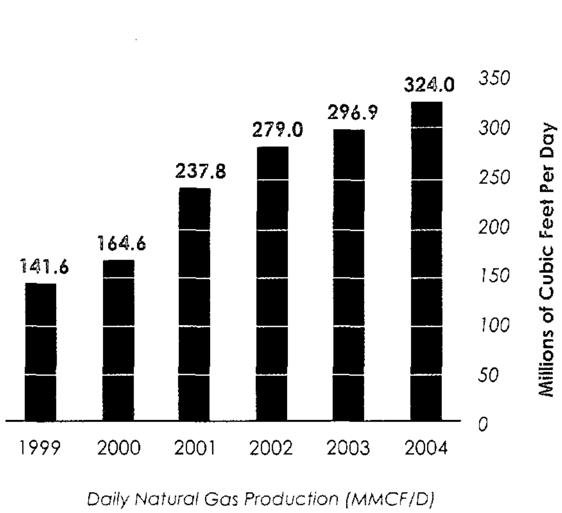


Figure F: Natural Gas Production Profile

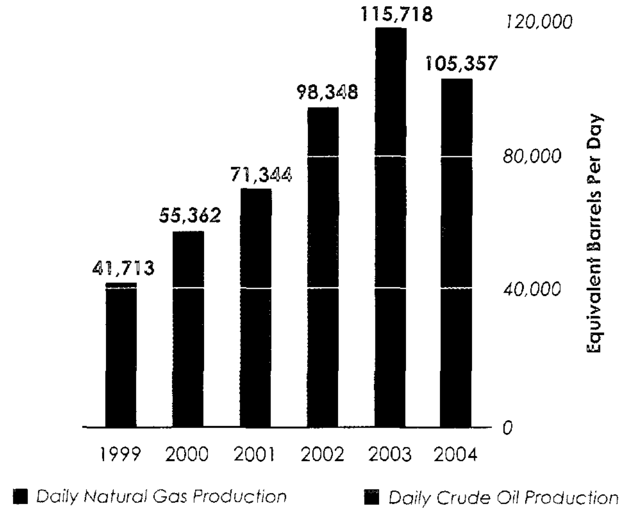
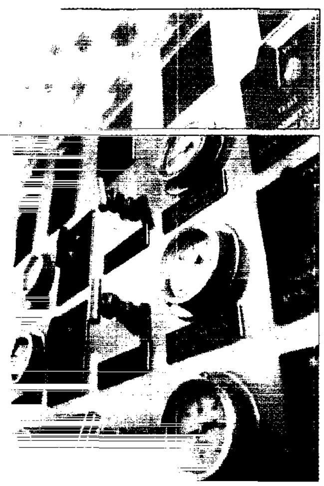


Figure G: Daily Cumulative Hydrocarbon Production



NATURAL GAS PRODUCTION REACHES A RECORD, CRUDE OIL SALES STAY HIGH DESPITE 2004 SHUT-INS

Pogo and its primary joint venture partner in the Gulf of Thailand shut-in production for about 45 days in early 2004 to effect facilities upgrades at the oil-rich Benchamas field. Later in the year, Hurricane Ivan struck the east-central part of the Gulf of Mexico, causing a curtailment of production from several of Pogo's fields including its fine oil field at Main Pass Blocks 61/62. Notwithstanding those production postponements, Pogo's 2004 oil production recorded its second highest volumes in its 35-year history, trailing only 2003.

Natural gas production in 2004, although affected by those same events, nevertheless reached best-ever levels, 9% higher than 2003 record highs, averaging 324 mmcf/d. **See Figure F.** Combining natural gas with crude oil and other liquid hydrocarbons, Pogo's total equivalent 2004 production topped 105,000 barrels per day. **See Figure G.**

DRILLING PACE IN 2004 WAS POGO'S FASTEST EVER

Most every geographic region enjoyed its fastest development drilling ever. Hurricane-related delays of Pogo's planned "six-pack" of OCS exploration wells caused most of that program to fall into 2005. In the Company's other geographic regions, 2004 exploration drilling was forced to take a back seat to the abundance of available development projects. Pogo finished the year having drilled a worldwide total of 363 gross wells, with 47 other wells drilling, completing or testing at year-end. That total of 363 gross wells, mostly developmental in nature, was 46% higher than 2003, Pogo's previous fastest drilling pace. More important, 93% of the wells Pogo drilled last year were successfully completed as producers. **See Figure H.**

Broken out by geographic regions, the gross wells drilled and successfully completed in 2004 look like this:

REGION	GROSS WELLS	SUCCESSFUL
Gulf of Mexico	12	10
Permian Basin	142	138
Gulf Coast Onshore	54	49
Wyoming	50	45
San Juan-New Mexico	17	17
Gulf of Thailand	78	77
Hungary	9	1
Denmark-North Sea	1	0

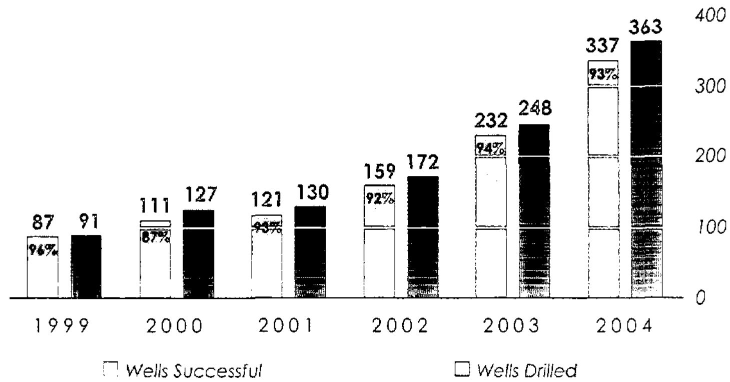
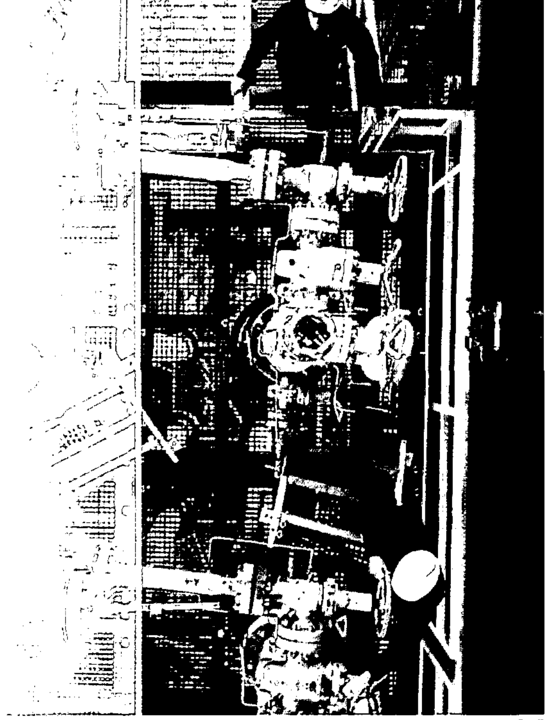
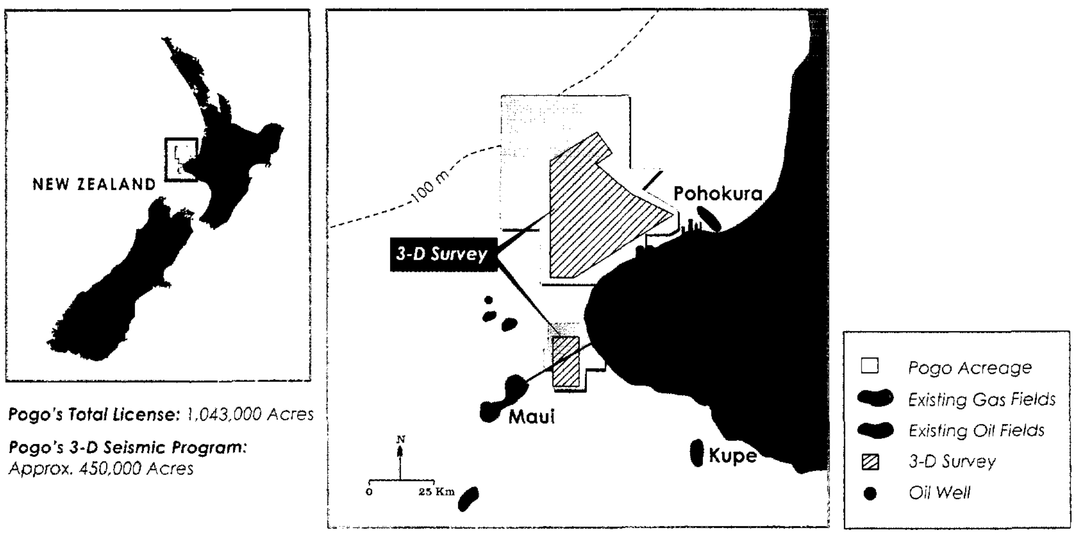


Figure H: Total Wells Drilled By Year
Success Rate





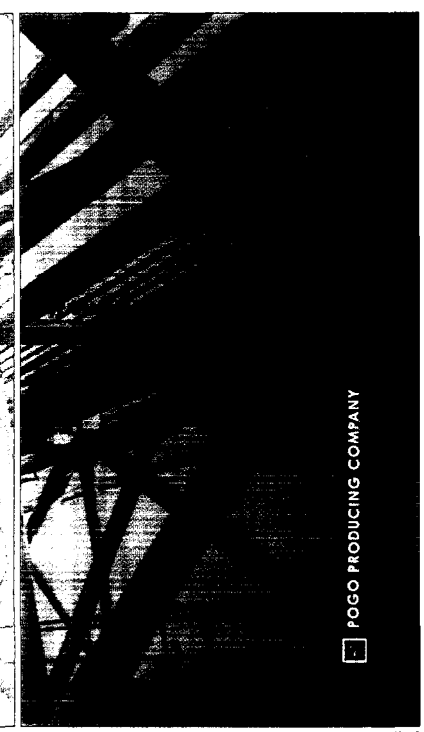
Map I: Pogo's 2005 3-D Seismic Program In New Zealand

OPERATIONS TO WATCH IN 2005

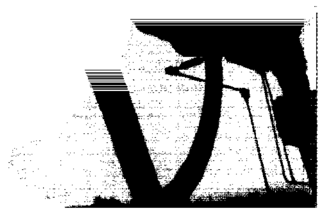
In the six-well OCS exploratory program, only two wells reached conclusion by year-end: a successful well at Main Pass Block 72-5 ST No. 1 and a dry hole at Mississippi Canyon Block 618. Since the end of the year, a well has encountered commercial hydrocarbons at Ewing Bank Blocks 948/992, while a dry hole was recorded at South Marsh Island Block 6. The final two wells in that six-well program, Ewing Bank Blocks 950/906 and Eugene Island Block 256, are still being drilled. Development operations will follow the successful wells, and a new, significant offshore exploration program is being planned for later this year.

Exploratory drilling in Thailand in 2005 will include at least four and probably more wells. Two of those important exploration wells already have been successfully completed, the Chaba No. 4 which logged 71 feet of oil pay, and the very impressive Benchamas No. 28 which encountered oil and gas pay measuring 365 feet! Other exploration wells will target Maliwan and North Jarmjuree fields.

A 3-D acquisition program in New Zealand covering about 450,000 acres kicked-off in January 2005. Data generated from that seismic shoot will be analyzed later this year in anticipation of an exploratory drilling program to begin in early 2006. **See Map I.**



BOARD OF DIRECTORS (From L to R): Jerry M. Armstrong, Stephen A. Wells, Carroll W. Suggs, Thomas A. Fry III, Paul G. Van Wagenen, Gerrit W. Gong, William L. Fisher and Robert H. Campbell



STRATEGIES FOR 2005 AND BEYOND

This year, Pogo will focus upon exploration drilling and more property acquisitions. Development drilling will be postponed in instances where no leases will be lost, and no drainage will occur. Such drilling postponement is in response to high current drilling and service costs. We are estimating the drilling pause will postpone the drilling of about 210 gross development wells across virtually all geographic regions, resulting in a 2005 capital budget savings of about $280 million. Pogo's initial 2005 capital and exploration budget authorization of $345 million envisions drilling 45 exploration wells and 181 development wells. As always, those budget numbers will be revisited throughout the year depending upon several factors, including Pogo's ongoing exploratory drilling success, changes in drilling and service costs, and volatile energy prices.

The "American Jobs Creation Act of 2004" created a one-year window of opportunity to tax-efficiently repatriate foreign investments, possibly including Pogo's important Thailand "legacy" asset, allowing reinvestment of the proceeds in domestic projects. For that reason, Pogo, with the help of its investment bankers, is now exploring whether an acceptable price can be obtained for Pogo's Thailand and Hungary assets. If an acceptable price is offered, Pogo would be able to redirect that capital toward domestic projects. If such a favorable price is not available, Pogo will not sell. To be sure, there is still much drilling and producing left to be done in Thailand, and a smaller scale development project is already underway in Hungary.

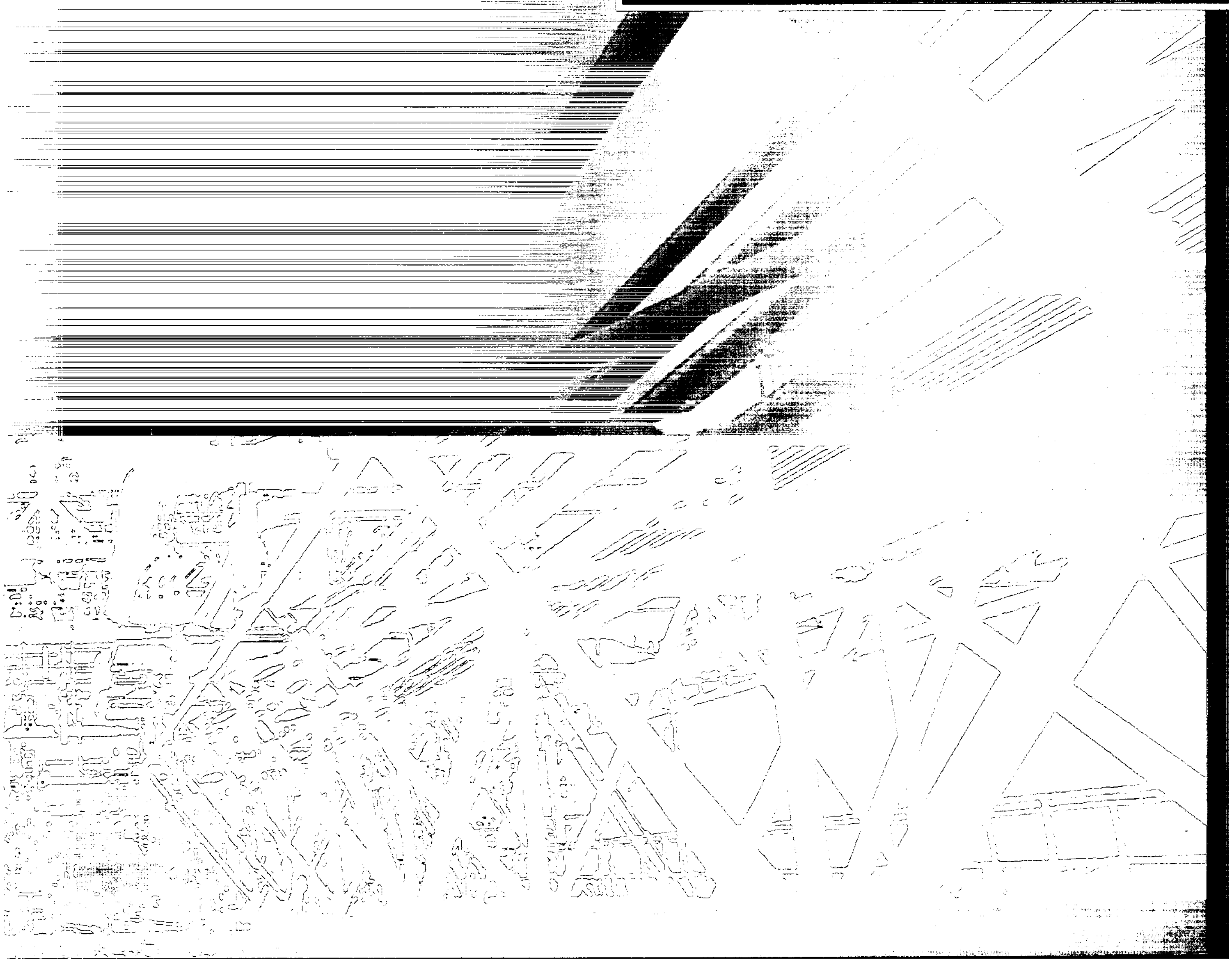
Pogo is building an inventory of good projects covering every stage of the exploration-development cycle. Additional good projects are already in the works, both domestically and internationally. Meanwhile, Pogo has been storing its considerable dry powder. Our debt ratios are very good, a new 2004 bank credit facility is in place and the capital markets remain strong as we enter 2005. Growth is on our minds.

Faithfully,

Paul G. Van Wagenen

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

FORM 10-K



UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2004

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

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

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

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 $3,200,000,000 as of June 30, 2004 (based on $49.40 per share, the last sale price of the Common Stock as reported on the New York Stock Exchange Composite Tape on such date).

63,601,714 shares of the registrant's Common Stock were outstanding as of March 1, 2005.

DOCUMENT INCORPORATED BY REFERENCE

Portions of the Company's definitive Proxy Statement respecting the annual meeting of shareholders to be held on April 26, 2005 (to be filed not later than 120 days after December 31, 2004) 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, 2004 (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 and information related to production contained in this Annual Report, unless otherwise noted, are reported on a "net" basis. Information regarding 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, New Zealand and in Hungary. As of December 31, 2004, the Company had interests in 91 lease blocks offshore Louisiana and Texas, approximately 705,000 gross acres onshore in the United States, approximately 588,000 gross acres offshore in the Kingdom of Thailand, approximately 778,000 gross acres in Hungary, and approximately 1,044,000 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, the Panhandle of Texas, 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 currently oversees activity principally in Hungary. 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. Approximately 18% of the Company's proved reserves as of December 31, 2004 were located in the Gulf of Mexico. During 2004, approximately 18% of the Company's natural gas production and 44% of its oil and condensate production came from the Company's domestic offshore properties, contributing approximately 33% of the Company's consolidated oil and gas revenues. The Company's exploration and development efforts in this region 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 domestic 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 2004 were approximately $150,300,000, or 148% higher than the Company's domestic offshore capital and exploration expenditures of approximately $60,500,000 for 2003, and 15% higher than the Company's domestic offshore capital and exploration expenditures of approximately $130,265,000 for

2002. The increase in the Company's domestic offshore capital and exploration expenditures for 2004, compared with 2003, resulted primarily from increased expenditures for exploration and development wells and facilities construction. During 2004, the Company invested approximately $87,695,000 on exploration and development wells and $22,952,000 on facilities construction for its Gulf of Mexico operations. The Company has currently budgeted approximately $109,000,000 for capital and exploration expenditures during 2005 in the Gulf of Mexico, of which $59,803,000 is budgeted for exploration and development wells and $15,976,000 for facilities construction.

The Company maintains a significant presence in the Gulf of Mexico where it participated in drilling 12 wells during 2004, 83% of which were considered successful. At December 31, 2004, the Company held varying interests in 175 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 59 of the 91 offshore leases in which it had an interest as of December 31, 2004.

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, 2004, the Company owned interests in 78 federal leases and 13 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 14 offshore leases at the lease sale conducted by the Minerals Management Service of the Department of the Interior (the "MMS") on March 17, 2004. 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. 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 and Thibodaux, Louisiana. The Company's Western U.S. region has an office in Midland, Texas, two field offices in Southeastern New Mexico, one field office in West Texas and two field offices in the Panhandle of Texas. The Company conducts its onshore operations in the United States directly and through its wholly owned subsidiaries. Domestic onshore reserves as of December 31, 2004, accounted for approximately 63% of the Company's total proved reserves, with the Gulf Coast region and the Western U.S. region contributing approximately 19% and 44%, respectively, of the Company's total proved reserves. During 2004, approximately 58% of the Company's natural gas production and 21% of its oil and condensate production was from its domestic onshore properties, contributing approximately 41% of the Company's consolidated oil and gas revenues.

Exploration and Development

The Company's onshore capital and exploration expenditures for 2004 were approximately $196,500,000 (excluding approximately $489,600,000 of net property acquisitions), or 38% higher than comparable expenditures for 2003, and approximately 48% higher than comparable expenditures for 2002. The increase in the Company's onshore capital and exploration expenditures for 2004, compared to 2003, resulted primarily from expenditures related to increased exploratory and development drilling. The Company has currently budgeted approximately $170,300,000 for capital and exploration expenditures during 2005 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.

Western U.S. Region. The Company's Western U.S. region has actively explored in West Texas and New Mexico for more than 25 years and, during this period, has participated in the discovery or development of over 31 oil and gas fields. In 2004, the Company participated in the drilling of 159 wells in these areas (97% of which were successfully completed). The Company believes that, during the past decade, it has been one of the more active companies drilling for oil and natural gas in the Permian Basin of West Texas and southeastern New Mexico.

During 2005, the Company plans to drill approximately 84 wells in various known fields and exploratory prospects located in the Permian Basin and Texas Panhandle. Drilling objectives for these wells range in vertical depth from 3,200 feet to 18,500 feet below the surface and target numerous formations, including, among others, the Brown Dolomite, Canyon, Delaware (Brushy Canyon), Bone Spring, Spraberry, Wolfcamp, Granite & Atoka Wash, and Pennsylvanian 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 14.5% across the unit area. Recent drilling activity in the Madden Deep Unit has focused on the Lower Fort Union formation (where productive zones are historically found from approximately 5,500 feet to 9,500 feet below the surface). Additionally, a 16,950-foot Cody test well has been drilled in this Unit and is currently awaiting completion.

An active Rocky Mountain drilling program of approximately 57 wells is anticipated for 2005. In addition to the Company's continued participation in the development of the Madden Deep Unit, the

Company also plans to initiate several exploratory tests elsewhere in Wyoming that will target the Lower Fort Union and Lance formations at total depths ranging from 10,000 feet to 11,000 feet.

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 2004, the Gulf Coast region participated in drilling 54 wells, 91% of which were successfully completed.

The Company's most active drilling in its Gulf Coast region during 2004 drilling took place on its 65,000 gross acres of leasehold in South Texas' Webb and Zapata Counties. The Company has been developing gas reserves primarily in its Los Mogotes, Hundido and South Hundido 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. At its Los Mogotes Field, where its working interest averages 71%, the Company drilled 37 wells in 2004. There were 62 locations identified to drill at Los Mogotes at the beginning of 2005, and the Company has already successfully drilled six of those. A total of six wells were drilled in the Company's 100%-owned South Hundido Field in 2004 and one has already been drilled in 2005. A new exploratory well was recently completed successfully by the Company on the South Rosita Prospect in Duvall County, Texas. Additional exploratory and development drilling is planned for this prospect. The Company intends to actively explore in various portions of the Wilcox trend of Texas during 2005.

During 2004, the Company participated in drilling several Miocene wells and several Oligocene wells in South Louisiana. In the Upper Texas Gulf Coast, the Company is actively exploring the Woodbine Formation for new gas reserves in Polk and Tyler Counties, Texas.

Property Acquisitions

In four transactions in 2004, the Company acquired interests in producing properties located primarily in Hidalgo and Lavaca Counties in the Texas Gulf Coast area, the San Juan Basin in New Mexico and in several counties in West Texas. In two additional transactions during 2004, the Company increased its working interest in the Myette Point Field from approximately 25% to 50%, and in the Thibodaux Field from approximately 48% to 60%.

International Operations

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

Thailand and Hungary Disposition

The Company announced during the first quarter of 2005 that it would consider the sale or swap of the Company's operations in Thailand and Hungary, and that it has retained Goldman, Sachs & Co. to advise it on the potential transactions. International asset sale proceeds could be favorably treated by the one-time tax provisions of the "American Jobs Creation Act of 2004," if the sale is completed and the proceeds are repatriated by year-end 2005. Exploration activities in Thailand and development activities in both Thailand and Hungary will continue during the Company's consideration of the sale of its operations.

Exploration and Development

The Company's international capital and exploration expenditures were approximately $148,900,000 for 2004, or 8% higher than comparative expenditures for 2003, and 44% higher than comparable expenditures for 2002. The increase in the Company's capital and exploration expenditures for 2004 resulted primarily from expenditures for facilities costs and increased drilling activity.

The Company has currently budgeted approximately $66,000,000 for capital and exploration expenditures during 2005 in areas outside the United States, including approximately $51,200,000 in Thailand and $4,800,000 in Europe. These budgeted numbers presume the sale of the Company's Thailand and Hungarian operations is consummated on or around the middle of the year. If the sale of the Company's Thailand Concession does not take place in mid-2005, these budgeted amounts will need to be increased, since additional capital expenditures in Thailand related to facilities construction and long-term rig contracts have already been contracted for through the end of the year and are, therefore, essentially non-discretionary in nature. In addition, the Company has budgeted approximately $10,000,000 for 2005 for its international new venture operations in New Zealand and elsewhere.

Asia and Pacific Region

The Company's Thailand Concession consists of approximately 588,000 acres in the central portions of the Gulf of Thailand, about 250 miles south southeast of Bangkok in approximately 230 feet of water. 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"), and Palang Sophon Limited ("Palang"). Chevron owns, directly and indirectly, a 51.66% working interest in the Thailand Concession and is currently the operator of the Thailand Concession. The remaining 2% working interest in the Thailand Concession is owned by Palang Sophon Two Limited, a private entity controlled by members of the Sophonpanich family. Through voting procedures in the joint operating agreement governing the Thailand Concession, and the close working relationship between Chevron's and Thaipo's exploration staff, Thaipo exerts substantial influence over the development of the Thailand Concession. As of December 31, 2004, the Company's proved reserves located in the Kingdom of Thailand accounted for approximately 19% of the Company's total proved reserves. During 2004, approximately 25% of the Company's natural gas production and 35% 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 132,000 acres is designated as the Benchamas and Pakakrong production area and another portion is known as the Benchamas North production area. Collectively, these two production areas are called the "Benchamas Field." There are 14 production platforms installed in the Benchamas Field. An additional four platforms for the Benchamas Field are currently under construction and expected to be set commencing in late 2005. 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. 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." During 2004, 49 productive development wells, including one horizontal well, were drilled in the Benchamas Field. In addition, in early January 2005, an exploration well, the Benchamas 28, encountered 365 feet of pay confirming the need for at least one additional platform there. For 2005, an active development 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—Crude Oil and Condensate—Production." During 2004, 15 productive development wells were drilled in the field. Currently, there is production from six platforms. 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 Block 9A was designated a production area in 2004. It is planned to be developed from and through existing Tantawan Field facilities. Current plans call for 2005 to be the most active development drilling program in the history of the field, with over 30 wells currently planned from five platforms.

Maliwan Field. Approximately 91,000 acres of the Thailand Concession are designated as the Maliwan production area or the "Maliwan Field." Eleven exploration wells have been drilled to delineate this field. An additional exploration well is currently planned for the latter half of 2005. In addition, seven production wells have been drilled from the first platform set in the field, the Maliwan "A" platform. Production from this platform is delivered to the central Benchamas Field production handling facilities for processing and sale. Current plans call for an additional eight development wells to be drilled from this platform in 2005. In addition, a second platform should be set in this field late in 2005. Final development plans for the remainder of the field are currently being finalized with our partners with the intent of sanctioning this project within the next several months.

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, was set in the second quarter of 2004 and 12 development wells were successfully drilled there. Additional exploration and development drilling is currently expected to occur in 2005. Production from this platform is 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 in conjunction with the development plans for the Maliwan Field.

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 2004, Thaipo and its joint venture partners drilled two exploratory wells and have currently budgeted to drill an additional four exploratory wells during 2005. Two of these wells, the Benchamas 28 discussed earlier, and the Chaba 4 have already been drilled. Each of these two wells encountered potentially commercial quantities of hydrocarbons. Two more wells are planned for later this year. Interpretation of the data provided by these wells and existing 3-D seismic and other 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 first fourteen production platforms and related facilities installed in the Tantawan, Benchamas and Maliwan Fields averaged approximately $17,400,000 per platform. The gross cost of each of the five "third generation" platforms currently under construction is currently expected to average approximately $10,000,000 per platform. Efforts are currently underway to design and construct even less expensive platforms. 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, 2005. No more extensions can be obtained. On July 31, 2005, all acreage for which production area status has not been granted or applied for will revert to the government of Thailand. Prior to that date, the Company and its joint venture partners currently intend to apply for a production area designation for all remaining acreage in the Thailand Concession that has not already been designated a production area. 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. To date, the Benchamas Field (including the North Benchamas area), Tantawan Field (including Block 9A), Maliwan Field and Jarmjuree Field have been designated as production areas. The earliest date at which any of these production areas could revert to the government is June 15, 2017 (with respect to portions of the Tantawan Field).

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 made significant SRB payments during 2004 and expects to be obligated to pay additional SRB during 2005. 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 2004, gas production averaged approximately 197 MMcf per day (80 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% through January 1, 2006) of the then-current sales price of the gas not delivered. Thaipo currently meets the minimum DCQ, but due to facilities constraints and process-related issues, has recently been unable to meet all of its Supplemental DCQ requirements. The price that the Company receives for its natural gas under the Gas Sales Agreement reflects the Company's underdelivery of Supplemental DCQ. However, the reduction in revenue related penalty is not considered significant by the Company, amounting to a discount on delivered gas (net to the Company) of less than approximately $499,000 for all of 2004. There can be no assurance that Thaipo will be able to meet its DCQ and Supplemental DCQ obligations 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, 2004, the Company was receiving a blended average price of approximately $2.46 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 778,000 acres. The exploration term of the license is currently set to expire on April 20, 2007. 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 of the Company's 3-D surveys 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. During its drilling program that commenced in 2003, Pogo Hungary has drilled nine wells, seven of which were either temporarily or permanently abandoned.

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. One well was drilled during 2004 pursuant to this license, which has been abandoned. This license interest was held by the Company's Danish subsidiary, Pogo Denmark ApS, and expired on September 14, 2004.

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. The joint venture relinquished its interest in the license area back to the Department of Trade and Industry on December 23, 2003.

New Zealand. During 2004, the Company was granted three petroleum exploration licenses over approximately 1,044,000 acres in the offshore Northern Taranaki Basin. The primary exploration term of these licenses is for five years, subject to extension for 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 and to reprocess 433 miles of existing 2-D seismic data. During 2004 and early 2005, the Company exceeded its work obligations with respect to both 3-D data acquisition and 2-D seismic data reprocessing. The 3-D seismic data acquired by the Company is currently being processed and will then be analyzed later this year with a goal of committing to drill multiple exploration wells as early as the first half of 2006. 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.

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 market successfully 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 platforms located in the northern portion of the Maliwan Field and the Jarmjuree Field, respectively, are initially stored aboard the FSO. A portion of this production is sold under a term sales agreement with Pacific Petroleum and Trading Co., Ltd. that expires in August 2005. 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 2004, the price that the Company received for its crude oil production from the Thailand Concession ranged between a $1.50 per Bbl premium and a $1.65 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 2004, crude oil sales to two customers (Pacific Petroleum and Trading Co., Ltd. and Shell Trading Company) constituted more than 10% of the Company's consolidated revenues.

Risks Associated with Acquisitions

From time to time the Company acquires additional interests in oil and gas properties, either through acquisition of the properties themselves or, 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, 2004, the Company was a party to certain natural gas or crude oil option contracts (see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Current Hedging Activity"). 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 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, 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, 2004:

	Developed Acreage(a)		Undeveloped Acreage(b)	
	Gross	Net	Gross	Net
Domestic Offshore				
Louisiana	138,374	57,059	184,155	160,706
Texas	17,280	8,101	5,760	1,152
Total Domestic Offshore	155,654	65,160	189,915	161,858
Domestic Onshore				
Louisiana	15,570	4,440	8,286	4,802
New Mexico	89,455	69,137	78,400	60,524
Texas	241,823	139,113	116,138	91,987
Wyoming	29,645	3,716	119,066	83,837
Other	6,520	2,211	—	—
Total Domestic Onshore	383,013	218,617	321,890	241,150
Total Domestic	538,667	283,777	511,805	403,008
International				
Gulf of Thailand	415,603	192,597	172,503	79,940
New Zealand	—	—	1,043,806	1,043,806
Hungary	—	—	777,588	777,588
Total International	415,603	192,597	1,993,897	1,901,334
Total Company	954,270	476,374	2,505,702	2,304,342

(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, Block 9A, Maliwan and Jarmjuree production licenses.

(b) Approximately 8.3% of the Company's total domestic offshore net undeveloped acreage is under leases that have minimum terms expiring in 2005 and no leases set to expire in 2006. Approximately 7.2% of the Company's total domestic onshore net undeveloped acreage is under leases with minimum terms expiring in 2005 and another 27.2% expires in 2006. All of the Company's undeveloped acreage in the Kingdom of Thailand has an exploratory term expiring July 31, 2005. See "International Operations; Contractual Terms Governing the Thailand Concession and Related Production."

In addition, the Company holds 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.

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." Production (lifting) costs are defined as the sum of lease operating expenses (which include insurance and producing well overhead), production and other taxes and transportation costs.

	2004	2003	2002
Average Production (Lifting) Costs per Mcfe(a):			
Located in the United States	$0.97	$0.68	$0.69
Located in the Kingdom of Thailand	$1.00	$0.67	$0.59
Total Company	$0.98	$0.68	$0.66

(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.

Productive Wells and Drilling Activity

The following table shows the Company's interest in productive oil and natural gas wells as of December 31, 2004. 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)		Total	
	Gross	Net	Gross	Net	Gross	Net
Offshore	**120**	**61.30**	**55**	**27.5**	**175**	**88.8**
Operated	50	23.00	23	17.0	73	40.0
Nonoperated	70	38.30	32	10.5	102	48.8
Domestic Onshore	**1407**	**862.63**	**1531**	**892.3**	**2938**	**1754.9**
Operated	842	769.94	953	795.2	1795	1565.1
Nonoperated	565	92.69	578	97.1	1143	189.8
Thailand	**102**	**47.27**	**71**	**32.9**	**173**	**80.2**
Operated	—	—	—	—	—	—
Nonoperated	102	47.27	71	32.9	173	80.2
Total	**1629**	**971.20**	**1657**	**952.7**	**3286**	**1923.9**
Operated	892	792.94	976	812.2	1868	1605.1
Nonoperated	737	178.26	681	140.5	1418	318.8

(a) One or more completions in the same bore hole are counted as one well. The data in the above table includes 24 gross (10.5 net) oil wells and 6 gross (1.9 net) natural gas wells with multiple completions.

(b) The Company was in the process of drilling a total of 15 gross (6.9 net) oil wells and 32 gross (16.3 net) natural gas wells as of December 31, 2004.

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 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. For accounting purposes, a well is considered a dry hole when the above criteria indicates that proved reserves have not been found. For purposes of this table, a well is classified as a dry hole in the period in which the Company reports permanent abandonment to the appropriate agency.

	2004		2003		2002	
	Productive	Dry	Productive	Dry	Productive	Dry
Gross Wells:						
Offshore United States						
Exploratory	2.0	2.0	5.0	2.0	5.0	2.0
Development	8.0	—	3.0	—	13.0	—
Onshore North America						
Exploratory	1.0	5.0	9.0	3.0	1.0	4.0
Development	248.0	9.0	169.0	9.0	83.0	5.0
Offshore Kingdom of Thailand						
Exploratory	1.0	1.0	5.0	1.0	6.0	—
Development	76.0	—	40.0	1.0	51.0	2.0
Europe						
Exploratory	1.0	9.0	1.0	—	—	—
Development	—	—	—	—	—	—
Total	337.0	26.0	232.0	16.0	159.0	13.0
Net Wells:						
Offshore United States						
Exploratory	1.6	1.8	2.3	2.0	5.0	2.0
Development	6.2	—	2.2	—	8.8	—
Onshore North America						
Exploratory	0.6	3.8	5.9	2.0	0.8	3.2
Development	122.4	4.6	75.9	3.5	54.7	3.4
Offshore Kingdom of Thailand						
Exploratory	0.5	0.5	2.3	0.5	2.8	—
Development	35.2	—	18.5	0.5	23.5	0.9
Europe						
Exploratory	1.0	8.4	1.0	—	—	—
Development	—	—	—	—	—	—
Total	167.5	19.1	108.1	8.5	95.6	9.5

Reserves

The following table sets forth information as to the Company's net proved and proved developed reserves as of December 31, 2004, 2003 and 2002, 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 reports prepared by the Company and reviewed by Miller and Lents, Ltd. ("Miller and Lents"), in accordance with criteria prescribed by the Commission. The summary reports of Ryder Scott and Miller and Lents, independent petroleum engineering firms, 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 all of the Company's reserves, except for certain domestic onshore areas on the Texas/Louisiana Gulfcoast and in Wyoming, which are covered by the Miller and Lents report.

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,		
	2004	2003	2002
Total Proved Reserves:			
Oil, condensate and natural gas liquids (MBbls)			
Located in North America	83,866	77,553	80,092
Located in the Kingdom of Thailand	32,517	37,307	38,087
Located in Hungary	—	10	—
Total Company	116,383	114,870	118,179
Natural Gas (MMcf)			
Located in North America	933,981	837,004	713,906
Located in the Kingdom of Thailand	145,689	165,188	159,604
Located in Hungary	—	10,131	—
Total Company	1,079,670	1,012,323	873,510
Present value of estimated future net revenues, before income taxes (in thousands)			
Located in North America	$3,639,307	$2,928,663	$2,495,558
Located in the Kingdom of Thailand	932,615	744,822	602,798
Located in Hungary	—	16,516	—
Total Company	$4,571,922	$3,690,001	$3,098,356
Total Proved Developed Reserves:			
Oil, condensate and natural gas liquids (MBbls)			
Located in North America	72,967	67,391	74,041
Located in the Kingdom of Thailand	19,607	19,878	23,832
Located in Hungary	—	—	—
Total Company	92,574	87,269	97,873
Natural Gas (MMcf)			
Located in North America	769,754	702,836	600,255
Located in the Kingdom of Thailand	83,095	77,938	87,301
Located in Hungary	—	—	—
Total Company	852,849	780,774	687,556
Present value of estimated future net revenues, before income taxes (in thousands)			
Located in North America	$3,122,860	$2,455,495	$2,239,781
Located in the Kingdom of Thailand	629,541	458,511	422,219
Located in Hungary	—	—	—
Total Company	$3,752,401	$2,914,006	$2,662,000

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. The present value amounts set forth in the above table are, as indicated, before income taxes. For the Company's standardized measure of discounted future net cash flows from production of proved reserves, calculated *after* the estimated effect of future income taxes, see "Unaudited Supplementary Financial Data—Oil and Gas Producing Activities."

Natural gas liquids comprised approximately 13% of the Company's total proved liquids reserves and approximately 13% of the Company's proved developed liquids reserves as of December 31, 2004. 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,		
	2004	2003	2002
Initial Weighted Average Price (in Dollars):			
Oil, condensate and natural gas liquids (per Bbl)			
Located in North America	$40.82	$31.34	$28.72
Located in the Kingdom of Thailand	$40.86	$30.27	$32.41
Located in Hungary	$ —	$26.00	$ —
Natural Gas (per Mcf)			
Located in North America	$ 6.04	$ 5.70	$ 4.70
Located in the Kingdom of Thailand	$ 2.70	$ 2.51	$ 2.24
Located in Hungary	$ —	$ 4.82	$ —

In computing future revenues from gas reserves attributable to the Company's domestic interests, prices in effect at December 31, 2004, 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, 2004, 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, 2004, 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, 2004, 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 2004. 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 used as a basis for the estimates set forth above 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, 2004, 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.

American Jobs Creation Act of 2004

On October 22, 2004, the President signed the American Jobs Creation Act of 2004 (the "Act"). The Act creates a temporary incentive for U.S. corporations to repatriate accumulated income earned abroad by providing an 85% dividend received deduction for certain dividends from controlled foreign corporations. The deduction is subject to a number of limitations and, as of February 22, 2005, uncertainty remains as to how to interpret numerous provisions of the Act. As a result, the Company is not yet in a position to decide whether, and to what extent, it might repatriate foreign earnings that have not yet been remitted to the U.S., therefore, if technical corrections to the Act are passed, the Company may repatriate in 2005 an amount up to approximately $195.7 million of the cash and current investments held by international subsidiaries discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources." Assuming 15% of such cash is subject to tax at the U.S. statutory rate, the repatriation would be subject to a tax liability of approximately $10.2 million. This amount excludes any proceeds that may be realized from the potential sale of the Company's Thailand and Hungarian operations.

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 2004, the Company incurred capital expenditures of approximately $6,343,000 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 $1,475,000 for expenditures involving environmental control facilities during 2005, 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, 2004, the Company and its subsidiaries had 260 full-time employees, including six in its Bangkok, Thailand office and five 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 not material. 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, 2004.

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, 2004, 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	58	1991
Stephen R. Brunner	Executive Vice President—Operations	46	2002
Jerry A. Cooper	Executive Vice President and Regional Manager—Western United States	56	2002
John O. McCoy, Jr.	Executive Vice President and Chief Administrative Officer	53	2002
David R. Beathard	Senior Vice President—Engineering	46	2002
Gerald A. Morton	Senior Vice President and Regional Manager—Asia and Pacific	46	2003
James P. Ulm, II	Senior Vice President and Chief Financial Officer	41	2002
Thomas E. Hart	Vice President and Chief Accounting Officer	61	1999
Michael J. Killelea	Vice President, General Counsel and Corporate Secretary	42	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. 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.

PART II

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

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
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
2004		
1st Quarter	$39.25	$50.45
2nd Quarter	$44.85	$51.34
3rd Quarter	$41.19	$49.71
4th Quarter	$43.35	$51.33

As of February 1, 2005, there were 2,118 holders of record of the Company's Common Stock.

In 2003, the Company paid four quarterly dividends of $0.05 per share on its Common Stock. In 2004, the Company paid three quarterly dividends of $0.05 per share on its Common Stock. On October 19, 2004, the Company's dividend was increased by 25% to $0.0625 per share on its Common Stock and it paid one quarterly dividend at that amount during 2004. 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 entered into a new revolving credit facility on December 16, 2004 (the "Facility"), under which the Company has borrowed funds. The Facility and the Indenture relating to the Company's 8¼% 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 believe that either 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, 2004.

During the fourth quarter of the year ended December 31, 2004, no equity securities of the Company of any class registered by the Company 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.

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

In the following table, the Company's financial, production and other data for 2001 through 2004 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,				
	2004	2003	2002	2001(a)	2000(a)
	(Expressed in thousands, except per share and production data)				
Financial Data					
Revenues:					
Crude oil and condensate	$ 680,492	$ 651,334	$ 431,769	$ 261,226	$ 272,932
Natural gas	584,341	475,834	294,206	322,390	190,401
Natural gas liquids	43,392	32,376	24,426	12,461	15,869
Oil and gas revenues	1,308,225	1,159,544	750,401	596,077	479,202
Other	14,754	2,452	4,453	14,040	18,789
Total	$1,322,979	$1,161,996	$ 754,854	$ 610,117	$ 497,991
Income before cumulative effect of change in accounting principle	$ 261,754	$ 295,107	$ 107,031	$ 87,954	$ 89,023
Cumulative effect of change in accounting principle	—	(4,166)(b)	—	—	(1,768)(c)
Net income	$ 261,754	$ 290,941	$ 107,031	$ 87,954	$ 87,255
Per share data:					
Income before cumulative effect of change in accounting principle—					
Basic	$ 4.10	$ 4.72	$ 1.85	$ 1.72	$ 2.20
Diluted	$ 4.06	$ 4.60	$ 1.77	$ 1.62	$ 1.99
Cash dividends on common stock	$ 0.2125	$ 0.20	$ 0.12	$ 0.12	$ 0.12
Price range of common stock:					
High	$ 51.34	$ 49.50	$ 39.28	$ 34.50	$ 33.19
Low	$ 39.25	$ 34.29	$ 23.00	$ 20.45	$ 18.00
Basic weighted average number of common shares outstanding	63,848	62,538	57,963	51,031	40,445
Long-term debt at year end	$ 755,000	$ 487,261	$ 722,903	$ 792,561	$ 365,000
Minority interest at year end	$ —	$ —	$ —	$ 145,086	$ 144,913
Shareholders' equity at year end	$1,727,895	$1,453,653	$1,077,784	$ 824,885	$ 358,271
Total assets at year end	$3,481,109	$2,758,651	$2,491,593	$2,423,979	$1,114,649
Production (Sales) Data					
Net daily average production and weighted average price:					
Natural gas (Mcf per day)	324,000	297,000	279,000	237,800	164,600
Price (per Mcf)	$ 4.93	$ 4.39	$ 2.89	$ 3.71	$ 3.16
Crude oil and condensate (Bbl per day)	47,137	62,121	47,360	29,590	25,788
Price (per Bbl)	$ 39.23	$ 29.10	$ 24.89	$ 23.99	$ 28.92
Natural gas liquids (Bbl per day)	4,220	4,109	4,480	2,118	2,141
Price (per Bbl)	$ 28.09	$ 21.59	$ 14.94	$ 16.12	$ 20.25

	For the Year Ended December 31, 2004	2003	2002	2001	2000
	(Expressed in thousands)				
Capital Expenditures (including interest capitalized)					
Oil and gas:					
Domestic Offshore—					
Exploration	$ 54,300	$ 28,100	$ 33,600	$ 18,000	$ 18,700
Development	74,000	23,900	100,700	169,000	43,700
Purchase of reserves	24,700	—	—	87,700	—
Onshore North America—					
Exploration	29,000	26,200	14,500	38,300	19,700
Development	159,500	118,000	117,200	113,600	34,700
Purchase of reserves	583,800	177,700	—	1,027,200	8,400
International—					
Exploration	33,100	20,900	3,100	11,500	9,400
Development	121,700	123,000	109,300	64,700	51,500
Total oil and gas	1,080,100	517,800	378,400	1,530,000	186,100
Other	6,200	2,500	3,300	4,800	700
Total	$1,086,300	$520,300	$381,700	$1,534,800	$186,800

(a) The Company's financial statements for 2000—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.

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.

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. 2004 marked the thirteenth 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 and offshore New Zealand. The Company also seeks to maintain a balanced mixture of the gas/oil ratio of its proven reserves base.

At the end of 2004, proven reserves topped 1,778 Bcfe and production for the year averaged more than 105,000 BOE per day (632,000 Mcfe per day). 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 2004, oil and gas pricing for the Company was strong, with the average price increasing 24% over 2003 on an equivalent barrel basis.

The Company continues to have a strong balance sheet and to improve its financial leverage, although long-term debt increased, primarily as a result of acquisitions, to $755 million at December 31, 2004 from $487 million at year-end 2003. Interest charges were reduced from $46.3 million in 2003 to $29.3 million in 2004. The Company's debt to total capitalization ratio, an indicator of a company's financial strength, was 30%. Cash and cash equivalents increased from $179 million to $221 million at year-end 2004. Company management believes being fiscally conservative is essential to position the Company for future growth.

Oil and gas capital and exploration expenditures for 2004 were approximately $1,080 million. Exploration & development operations were allocated approximately $472 million, and approximately $608 million was spent on selective acquisitions in the Company's core areas of operations. During 2004, approximately 309 bcfe of proven reserves were added to the Company's reserves ledger.

Hurricane Ivan Update

Company operated Gulf of Mexico platforms did not sustain major damage as a result of Hurricane Ivan. However, damages to outside owned and operated platforms and pipelines are continuing to cause a portion of the Company's Gulf of Mexico production to remain shut-in. As of February 22, 2005 some 4,500 barrels of oil per day and 27 million cubic feet of natural gas per day from Main Pass, South Pass and Viosca Knoll areas remain shut-in. Repairs to the infrastructure are underway, and the Company expects to restore approximately 70% of the production from these fields by the end of March, 2005. In order to protect its cash flow, the Company has business interruption insurance for certain of the blocks affected by the shut-in; the Company expects to receive payment from its business interruption insurance policy until production is fully restored for a period of up to one year. The daily indemnity amount expected to be paid to the Company is approximately $600,000 per day for the Main Pass 61/62 Blocks and approximately $50,000 per day for other blocks affected by the shut-in. These amounts will be reduced by cash flow from partially restored production.

2005 Capital Budget

The Company has established a $345 million exploration and development budget (excluding property acquisitions). The Company expects to spend approximately $187 million on exploration and $158 million on development activities. The capital budget calls for the drilling of approximately 226 wells during 2005.

Thailand and Hungary Disposition

The Company announced during the first quarter of 2005 that it would consider the sale or swap of the Company's operations in Thailand and Hungary and has retained Goldman, Sachs & Co. to advise it on the potential transactions. International asset sale proceeds could be favorably treated by the tax provisions of the "American Jobs Creation Act of 2004", if completed by year-end 2005. Exploration activities in Thailand and development activities in both Thailand and Hungary will run concurrently with the Company's consideration of the sale of its operations.

Share Repurchase

During the first quarter of 2005, the Company announced a share repurchase plan. The Company expects to expend not less than $275 million nor more than $375 million dollars to effect the repurchases. Based on recent stock prices, the repurchase could represent approximately 9% to 12% of the shares outstanding at December 31, 2004.

2005 Production Outlook Update

The Company currently expects that 2005 equivalent hydrocarbon production should reach within 2% of the Company's 2004 production levels, subject to changes in circumstances, acquisitions, divestitures and many other factors.

Results of Operations

Oil and Gas Revenues

The Company's oil and gas revenues for 2004 were $1,308,225,000, an increase of approximately 13% from oil and gas revenues of $1,159,544,000 for 2003, which were an increase of approximately 55% from oil and gas revenues of $750,401,000 for 2002. The following table reflects an analysis of variances in the Company's oil and gas revenues (expressed in thousands) between years:

	2004 Compared to 2003	2003 Compared to 2002
Increase (decrease) in oil and gas revenues resulting from variances in:		
Natural gas—		
Price	$ 58,308	$152,879
Production	50,199	28,749
	108,507	181,628
Crude oil and condensate—		
Price	226,564	72,984
Production	(197,406)	146,581
	29,158	219,565
Natural gas liquids ("NGL")	11,016	7,950
Increase in oil and gas revenues	$ 148,681	$409,143

The increase in the Company's oil and gas revenues in 2004, compared to 2003, 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 production volumes, partially offset by a decrease in crude oil and condensate production volumes. 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 oil and gas revenues for 2004, compared to 2003 and 2002, was also the result of an increase in the average price that the Company received for its NGL production volumes from $14.94 and $21.59 in 2002 and 2003, respectively, to $28.09 in 2004.

Other Revenues

Other revenue is revenue derived from sources other than the current production of hydrocarbons. This revenue includes, among other items, insurance proceeds (excluding those related to operating expenses, which are credited against the appropriate expense category), pipeline imbalance settlements and revenue from salt water disposal activities. The increase in the Company's other revenues in 2004, compared to either 2003 or 2002, is related primarily to $11.1 million of business interruption insurance recorded in 2004 with no comparable insurance claims in either 2003 or 2002. The business interruption insurance claim relates to the shut-in of a significant portion of the Company's Gulf of Mexico production during the fourth quarter of 2004 as a result of the infrastructure damage caused by Hurricane Ivan. Repairs to the infrastructure are underway, and the Company expects to restore approximately 70% of the production from the affected fields by the end of March, 2005.

	2004	2003	% Change 2004 to 2003	2002	% Change 2003 to 2002
Comparison of Increases (Decreases) in:					
Natural Gas—					
Average prices					
North America(a)	**$ 5.73**	$ 5.17	**11%**	$ 3.15	**64%**
Kingdom of Thailand(b)	**$ 2.46**	$ 2.49	**(1)%**	$ 2.22	**12%**
Company-wide average price	**$ 4.93**	$ 4.39	**12%**	$ 2.89	**52%**
Average daily production volumes (MMcf per day):					
North America	**244.3**	210.4	**16%**	201.3	**5%**
Kingdom of Thailand	**79.7**	86.5	**(8)%**	77.8	**11%**
Company-wide average daily production	**324.0**	296.9	**9%**	279.1	**6%**
Crude Oil and Condensate—					
Average prices(c)					
North America	**$ 38.59**	$ 29.08	**33%**	$ 24.95	**17%**
Kingdom of Thailand	**$ 40.28**	$ 29.14	**38%**	$ 24.80	**18%**
Company-wide average price	**$ 39.23**	$ 29.10	**35%**	$ 24.89	**17%**
Average daily production volumes (Bbls per day):					
North America	**29,530**	40,173	**(26)%**	30,971	**30%**
Kingdom of Thailand(d)	**17,607**	21,948	**(20)%**	16,389	**34%**
Company-wide average daily production	**47,137**	62,121	**(24)%**	47,360	**31%**
Total Liquid Hydrocarbons—					
Company-wide average daily production (Bbls per day)(d)	**51,357**	66,230	**(22)%**	51,840	**28%**

(a) North American average prices reflect the impact of the Company's price hedging activity. The Company had no price hedging activity related to 2004 production. Price hedging activity reduced the average price $0.17 during 2003 and added $0.04 to the average price of the Company's North American natural gas production during 2002.

(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) Average prices are computed on production that is actually sold during the period and include the impact of the Company's price hedging activity. The Company had no price hedging activity related to 2004 production. 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 96,000 barrels less than it sold in 2004, 293,000 barrels more than it sold in 2003 and 58,000 barrels less than it sold in 2002.

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 25% of the Company's 2004 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 baht/dollar exchange rate and fuel oil prices in Singapore. The contract price is also subject to adjustments for quality. PTT has further 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) through December 31, 2007. 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. See "Business—International Operations; Contractual Terms Governing the Thailand Concession and Related Production."

Production. The increase in the Company's natural gas production during 2004, compared to 2003, was primarily related to acquisitions made during 2004 and late 2003 and, to a lesser extent, increased production from the continuing success of the Company's exploration program at its Los Mogotes Field in South Texas. These production gains were partially offset by shut-in production resulting from the infrastructure damage caused by Hurricane Ivan in the final months of 2004 and natural production declines at other properties. 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.

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 or Dated

Brent 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 month following production, the cost of the crude oil and the sales revenue are recognized in the income statement. As of December 31, 2004, the Company had approximately 399,000 net barrels stored on board the FPSO and FSO.

Production. The decrease in the Company's crude oil and condensate production during 2004, compared to 2003, resulted primarily from shut-in production related to the infrastructure damage caused by Hurricane Ivan in the final quarter of 2004, the temporary shutdown of the Benchamas field in the Gulf of Thailand during January and February of 2004 to upgrade the Benchamas central processing platform, natural production declines at the Company's Main Pass Blocks 61/62 Field in the Gulf of Mexico and processing problems at its Gulf of Thailand concession. 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.

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 2004, compared with 2003, related to an increase in the average price that the Company received for its NGL production to $28.09 in 2004 from $21.59 in 2003, in addition to a slight increase in NGL production volumes. 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.

Costs and Expenses

	2004	2003	% Change 2004 to 2003	2002	% Change 2003 to 2002
Comparison of Increases (Decreases) in:					
Lease Operating Expenses					
North America	**$ 100,535,000**	$ 81,731,000	**23%**	$ 74,416,000	**10%**
Kingdom of Thailand	**$ 43,938,000**	$ 41,367,000	**6%**	$ 38,247,000	**8%**
Total Lease Operating Expenses	**$ 144,473,000**	$ 123,098,000	**17%**	$112,663,000	**9%**
General and Administrative Expenses	**$ 69,775,000**	$ 61,291,000	**14%**	$ 49,490,000	**24%**
Exploration Expenses	**$ 23,063,000**	$ 7,547,000	**206%**	$ 4,783,000	**58%**
Dry Hole and Impairment Expenses	**$ 106,417,000**	$ 35,102,000	**203%**	$ 26,999,000	**30%**
Depreciation, Depletion and Amortization (DD&A) Expenses	**$ 365,089,000**	$ 325,820,000	**12%**	$287,809,000	**13%**
DD&A rate	**$ 1.57**	$ 1.29	**22%**	$ 1.33	**(3)%**
Mcfe sold	**231,937,152**	253,422,703	**(8)%**	215,728,000	**17%**
Production and Other Taxes	**$ 67,984,000**	$ 35,485,000	**92%**	$ 20,058,000	**77%**
Transportation and Other	**$ 21,699,000**	$ 25,924,000	**(16)%**	$ 12,879,000	**101%**
Interest—					
Charges	**$ (29,333,000)**	$ (46,360,000)	**(37)%**	$ (57,450,000)	**(19)%**
Capitalized Interest Expense	**$ 14,216,000**	$ 16,531,000	**(14)%**	$ 24,033,000	**(31)%**
Loss on debt extinguishment	**$ (13,759,000)**	$ (5,893,000)	**133%**	$ —	**N/M**
Minority Interest—Dividends and Costs	**$ —**	$ —	**N/M**	$ (4,140,000)	**N/M**
Income Tax Expense	**$ (234,649,000)**	$ (220,122,000)	**7%**	$ (97,780,000)	**125%**

Lease Operating Expenses

The increase in North American lease operating expenses for 2004, compared to 2003, is due primarily to increased expenses incurred on the properties acquired by the Company during 2004 and the latter part of 2003, increased maintenance expenses on several of the Company's significant offshore properties related to the effects of Hurricane Ivan and also to increased expenses incurred as the Company continues to expand production in the Los Mogotes field in South Texas. The increase in North American lease operating expenses for 2003, compared to 2002, was 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 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 lease operating expenses in the Kingdom of Thailand for 2004, compared to 2003, primarily related to costs associated with operating the five additional platforms which were added to the Gulf of Thailand during 2003 and the resulting increase in operating expenses as additional wells were brought on production during 2003. The Company added five new platforms during 2004 and expects to add five new platforms in 2005. 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. 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 $14,600,000 (net to the Company's interest) of the Company's Thailand lease operating expenses for 2004 and approximately $14,500,000 (net to the Company's interest) of the Company's Thailand lease operating expenses for 2003 and 2002. 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 two years. See "Liquidity and Capital Resources; Capital Requirements; Other Material Long-Term Commitments."

On a per unit of production basis, the Company's total lease operating expenses were $0.52 per Mcfe for 2002, $0.49 per Mcfe for 2003 and $0.62 per Mcfe for 2004. The increased unit costs in 2004 were primarily related to the increased expense associated with Hurricane Ivan remediation efforts and the decreased production volumes discussed above.

General and Administrative Expenses

The increase in general and administrative expenses for 2004, compared with 2003, is primarily related to increases in compensation and related benefit expense and to increased professional fees (due in part to compliance with Sarbanes-Oxley legislation). 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. On a per unit of production basis, the Company's general and administrative expenses were $0.30 per Mcfe in 2004, $0.24 per Mcfe in 2003 and $0.23 per Mcfe in 2002.

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 2004, compared to 2003, resulted primarily from increased 3-D seismic acquisition activities in the Gulf of Mexico and seismic operations in the Company's Gulf Coast division. 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 region.

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 2004 the Company drilled 17 gross unsuccessful exploratory wells (14.50 net to the Company's interest), in 2003 the Company drilled 6 unsuccessful exploratory wells (4.46 net to the Company's interest) and in 2002 the Company drilled 6 unsuccessful exploratory wells (5.17 net to the Company's interest). The Company had exploratory and development drilling success rates of 93% in 2004, 94% in 2003 and 92% in 2002. The Company had approximately $10,800,000 of exploratory wells in progress or temporarily abandoned pending evaluation (located primarily in the Gulf of Mexico) at December 31, 2004 that had not been evaluated as of March 1, 2005. The Company has also suspended approximately $12,057,000 in exploratory well costs related to wells completed more than one year prior to December 31, 2004 (located primarily in the Kingdom of Thailand) pending the determination of whether proved reserves can be ultimately assigned. These costs will be charged to earnings in a future period if the Company determines that proved reserves cannot be assigned.

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 $43,800,000 during 2004 (approximately $22,400,000 of which was related to the Company's international operations), approximately $10,542,000 during 2003 and $6,191,000 during 2002.

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 2004, compared to 2003, resulted primarily from a decrease in the percentage of the Company's production coming from fields that have DD&A rates that are lower than the Company's recent historical composite DD&A rate (principally properties in the Gulf of Mexico which were shut-in due to hurricane downtime, and the Benchamas field in the Gulf of Thailand which was shut-in for processing upgrades) and a corresponding increase in the percentage of the Company's production coming from fields that have DD&A rates that are higher than the Company's recent historical composite rate (principally increased production from domestic onshore properties acquired by acquisition).

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.

Production and Other Taxes

The increase in production and other taxes for 2004, compared to 2003, is primarily related to increased severance taxes due to higher domestic onshore production volumes and prices. The increase also relates to the recognition during 2004 of $23,880,000 of the Special Remunitory Benefit ("SRB") obligation incurred on the Company's Kingdom of Thailand concession. During 2003, the Company incurred $11,750,000 of SRB. 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 2005 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 but is expected to be significant. See "Business—International Operations; Contractual Terms Governing the Thailand Concession and Related Production."

The increase in production and other taxes for 2003, compared to 2002, relates to the recognition during 2003 of $11,750,000 of SRB obligations incurred on the Company's Kingdom of Thailand concession. No comparable SRB expenses were incurred in 2002. The increase is also related to increased severance taxes due to higher domestic onshore production volumes and prices.

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 obligations under an accounting pronouncement adopted on January 1, 2003, natural gas purchase 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 decrease in transportation and other expense for 2004, compared to 2003, relates primarily to a reduction in the Company's transportation expenses, and the inclusion in 2003 of approximately $3.2 million more of valuation allowances and reserves on items discussed above, than were expensed in 2004. 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 $13,318,000 in 2004, $12,980,000 in 2003 and $10,140,000 in 2002.

Interest

Interest Charges. The decrease in the Company's interest charges for 2004, compared to 2003, resulted primarily from a decrease in the average amount of the Company's outstanding debt during the first eleven months of the year and the repayment of higher cost debt during the year, resulting in a lower weighted average cost of debt. The Company did incur $317 million in additional debt during

December 2004 primarily related to acquisitions, but this did not have a significant impact on the Company's 2004 interest expense. 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.

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 2004, compared to 2003, resulted from a decrease 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, partially offset by an increase in the amount of capital expenditures subject to interest capitalization during 2004 (approximately $210,000,000) compared to 2003 (approximately $192,000,000). The decrease in capitalized interest for 2003, compared to 2002, 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). This decrease was also impacted by changes in the weighted average rate on borrowings incurred by the Company and applied to such capital expenditures to arrive at the total amount of capitalized interest.

Loss on Debt Extinguishment

The loss on debt extinguishment for 2004 is related to redemption premiums paid and/or unamortized debt issuance costs which were expensed due to the redemption of the 2009 Notes and the replacement of the Company's previous bank credit facility with a new credit facility. 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 2002.

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 and the jurisdiction in which the income is earned. The increase in the Company's tax expense for 2004, compared to 2003, resulted primarily from Hungarian exploration losses for which no tax benefit could be recognized. 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 Company's consolidated effective tax rate for 2004, 2003 and 2002 was 47%, 43% and 48%, respectively. The higher effective tax rate during 2004, compared to 2003, was primarily the result of the impairment of the Company's Hungarian operations for which no tax benefit was recognized due to the Company's inability to offset the costs against expected future taxable income in Hungary. The lower effective tax rate during 2003, compared to 2002, was 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. The Company announced in January 2005 that it would consider the disposition of its operations in Thailand and Hungary and therefore cannot currently predict whether foreign taxes will continue to constitute a substantial portion of its overall tax burden in future years. See "Liquidity and Capital Resources—American Jobs Creation Act of 2004".

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 2004 was $738,715,000. This compares to cash flow from operating activities of $744,559,000 in 2003 and $466,479,000 in 2002. The resulting changes are attributable to the reasons described under "Results of Operations" above. Cash flow from operating activities in 2004 was sufficient to fund 82% of the $901,006,000 in cash expenditures for capital and exploration projects and acquisitions for the year. To fund the remaining expenditures, the Company borrowed approximately $208,218,000 of cash (net of repayments and the redemption discussed below). The Company paid $13,607,000 of dividends on its common stock during 2004. As of December 31, 2004, the Company had cash and current investments of $221,456,000 (including $195,669,000 in international subsidiaries which the Company currently intends to reinvest in its foreign operations subject to its evaluation of the new tax provisions discussed in "American Jobs Creation Act of 2004" below) and long-term debt obligations of $755,000,000 with no principal repayment obligations until 2009. On April 19, 2004, the Company paid $157,782,000 (excluding accrued interest) in cash to holders of its 10⅜% Senior Subordinated Notes due 2009 (the "2009 Notes"). The redemption was made at 105.188% of the face amount of the 2009 Notes. The cash redemption payment was funded through borrowings under the Company's existing bank credit facility. The Company may elect to repurchase additional debt through market transactions, privately negotiated transactions or otherwise, depending on market conditions, liquidity requirements, contractual restrictions and other factors.

On December 16, 2004 the Company entered into a new Credit Agreement, replacing its then existing credit agreement dated as of March 8, 2001, as amended. The new Credit Agreement is with various financial institutions and provides for revolving credit borrowings up to a maximum principal amount of $750 million outstanding at any one time, with borrowings not to exceed a borrowing base determined at least semiannually. The borrowing base is currently $900 million. The Credit Agreement provides that in specified circumstances involving an increase in ratings assigned to the Company's debt, the Company may elect for the borrowing base limitation to no longer apply to restrict available borrowings. As of March 1, 2005, the Company had an outstanding balance of $520,000,000 under its Credit Agreement See "Capital Structure—Credit Agreement".

American Jobs Creation Act of 2004

On October 22, 2004, the President signed the American Jobs Creation Act of 2004 (the "Act"). The Act creates a temporary incentive for U.S. corporations to repatriate accumulated income earned abroad by providing an 85% dividend received deduction for certain dividends from controlled foreign corporations. The deduction is subject to a number of limitations and, as of March 1, 2005, uncertainty remains as to how to interpret numerous provisions of the Act. As a result, the Company is not yet in a position to decide whether, and to what extent, it might repatriate foreign earnings that have not yet been remitted to the U.S., therefore if technical corrections to the Act are passed the Company may repatriate in 2005 an amount up to approximately $195.7 million of the cash and current investments held by international subsidiaries discussed in "Liquidity and Capital Resources" above. Assuming 15% of such cash is subject to tax at the U.S. statutory rate, the repatriation would be subject to a tax liability of approximately $10.2 million. This amount excludes any proceeds that may be realized from the potential sale of the Company's Thailand and Hungarian operations.

Future Capital and Other Expenditure Requirements

The Company's capital and exploration budget for 2005, 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 $345,000,000. The Company has included 226 gross wells in its 2005 capital and exploration budget, including wells to be drilled in the United States and the Kingdom of Thailand. 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.

Stock Repurchase

On January 25, 2005, the Company announced a plan to repurchase, through open market or privately negotiated transactions, not less than $275 million nor more than $375 million of its common stock. As of March 1, 2005, the Company had completed the purchase of 940,200 shares at a total cost of $41.5 million.

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, 2004 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(a)	$ 858.7	$16.5	$ 33.0	$588.0	$221.2
Operating Lease Obligations(b)	$ 140.9	$23.5	$ 43.6	$ 26.7	$ 47.1
Purchase Obligations(c)	$ 55.9	$21.8	$ 21.6	$ 2.5	$ 10.0
Asset Retirement Obligations(d)	$ 269.1	$ 4.0	$ 4.9	$ 7.0	$253.2
Total	$1,324.6	$65.8	$103.1	$624.2	$531.5

(a) Includes interest on fixed rate debt but excludes variable rate interest expense on the Company's bank credit facility.

(b) 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.

(c) This represents: i) the Company's share of the contractual commitments for two rigs drilling in the Gulf of Thailand. 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.

(d) 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, 2004, 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 $8,500,000 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. 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 Agreement and Borrowing Base Determination

Credit Agreement. The Company has a revolving credit facility (the "Credit Agreement") that provides for a $750,000,000 revolving loan facility terminating on December 16, 2009. The amount that may be borrowed under the Credit Agreement may not exceed a borrowing base determined at least semiannually using the administrative agent's usual and customary criteria for oil and gas reserve valuation, adjusted for incurrences of other indebtedness since the last redetermination of the borrowing base. The borrowing base is currently $900 million. The credit agreement provides that in specified circumstances involving an increase in ratings assigned to Pogo's debt, Pogo may elect for the borrowing base limitation to no longer apply to restrict available borrowings. The next redetermination of the borrowing base is expected to occur by May 1, 2005. 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 Agreement 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 four substantially equal monthly installments, commencing not later than 90 days after the Company is notified of the new borrowing base. The Credit Agreement includes procedures for additional financial institutions selected by the Company to become lenders under the agreement, or for any existing lender to increase its commitment in an amount approved by the Company and the lender, subject to a maximum of $250 million for all such increases in commitments of new or existing lenders. The Credit Agreement also permits short-term swing-line loans up to $10 million and the issuance of letters of credit up to $75 million, which in each case reduce the credit available for revolving credit borrowings. As of March 1, 2005, there was $520,000,000 outstanding under the Credit Agreement.

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. The Company had upward reserve revisions equivalent to 0.28%, 5.19% and 8.09% of proved reserves during the years ended December 31, 2004, 2003 and 2002, respectively. These reserve revisions resulted primarily from improved performance from a variety of sources such as additional recoveries below previously established lowest known hydrocarbon levels, improved drainage from natural drive mechanisms, and the realization of improved drainage areas. If the estimates of proved reserves were to decline, the rate at which the Company records depletion expense would increase. Holding all other factors constant, a reduction in the Company's proved reserve estimate of 1% would result in an annual increase in DD&A expense of approximately $3.7 million.

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 impairment expense in each of the periods covered by this Form 10-K. 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 nor that they will not be material.

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 and sold.

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 2004, the Company grew through the acquisition of two corporations. These acquisitions were accounted for using the purchase method of accounting. 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. Goodwill and other intangibles with an indefinite useful life 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, the ultimate settlement amount, inflation factors, credit adjusted discount rates, timing of settlement and changes in the political, legal, environmental 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.

Holding all other factors constant, if the Company's estimate of future abandonment costs is revised upward, earnings would decrease due to higher DD&A expense. Likewise, if these estimates were revised downward, earnings would increase due to lower DD&A expense. It would require an increase in the present value of the Company's estimated future abandonment cost of approximately $13 million (representing an increase of approximately 14% to the Company's December 31, 2004 asset retirement obligation) to increase the Company's DD&A rate by $0.01 per Mcfe for the year ended December 31, 2004.

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 of operations. Any differences among these assumptions and the results actually experienced will also impact future results of operations. An analysis of the effect of a 1% change in health care cost trends on post-retirement benefits is included in Note 9 to the Consolidated Financial Statements.

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. See "Liquidity and Capital Resources—American Jobs Creation Act of 2004."

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 and to the effect of the recent tsunami disaster in the Kingdom. 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 three new pronouncements relevant to the Company's accounting. These are Statement of Financial Accounting Standards No. 123 (revised 2004) ("SFAS 123R"), "Share-Based Payment", Statement of Financial Accounting Standards No. 153 ("SFAS 153"), "Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29" and FASB Staff Position FAS 109-2 ("FSP FAS 109-2"), "Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision Within the American Jobs Creation Act of 2004".

SFAS 123R. SFAS 123R will require compensation costs related to share-based payment transactions to be recognized in the financial statements. With limited exceptions, the amount of compensation cost will be measured based on the grant-date fair value of the equity or liability instruments issued. In addition, liability awards will be remeasured each reporting period. Compensation cost will be recognized over the period that an employee provides service in exchange for the award.

Statement 123(R) replaces FASB Statement No. 123 ("SFAS 123"), "Accounting for Stock-Based Compensation", and supersedes APB Opinion No. 25, "Accounting for Stock Issued to Employees". SFAS 123R is effective as of the first interim or annual reporting period that begins after June 15, 2005. The Company currently follows the provisions of SFAS 123 and the adoption of SFAS 123R is not expected to have a material effect on the Company's financial statements.

SFAS 153. SFAS 153 was a result of an effort by the FASB and the International Accounting Standards Board ("IASB") to improve financial reporting by eliminating certain narrow differences between their existing accounting standards. One such difference was the exception from fair value measurement in APB Opinion No. 29, *Accounting for Nonmonetary Transactions*, for nonmonetary exchanges of similar productive assets. SFAS 153 replaces this exception with a general exception from fair value measurement for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. SFAS 153 will be applied prospectively and is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. Earlier application is permitted for nonmonetary asset exchanges occurring in fiscal periods beginning after the date of issuance of this Statement. The adoption of SFAS 153 is not expected to have a material effect on the Company's financial statements.

FSP FAS 109-2. In December 2004, the FASB staff issued FSP FAS 109-2 to provide accounting and disclosure guidance for the repatriation provisions included in the Act. The Act introduced a special limited-time dividends received deduction on the repatriation of certain foreign earnings to a U.S. taxpayer. As a result, an issue has arisen as to whether an enterprise should be allowed additional time beyond the financial reporting period in which the Act was enacted to evaluate the effects of the Act on its plan for reinvestment or repatriation of foreign earnings for purposes of applying Statement 109. The following are the key points relevant to the Company's position:

- An enterprise is allowed additional time beyond the financial reporting period of enactment to evaluate the effect of the Act without undermining the entity's assertion that repatriation of foreign earnings is not expected within the foreseeable future.
- An enterprise should recognize the income tax effect when it decides on a plan for reinvestment or repatriation of foreign earnings. This decision may occur in stages, and each stage may occur at a different time. Also, before its plan for reinvestment or repatriation is finalized, an enterprise may decide on a range of amounts that it will repatriate. In this situation, the FSP requires recognition of the income tax effect of the lowest amount within the range.
- If an enterprise has recognized a deferred tax liability for some, or all, of its unremitted foreign earnings because it did not overcome the presumption of repatriation of foreign earnings, it should continue to presume repatriation of those earnings as well as current foreign earnings that are not expected to be indefinitely reinvested. The enterprise shall measure the income tax effects of such repatriation without the effects of the repatriation provision until it has decided on a plan for repatriation.
- An enterprise that has not yet completed its evaluation of the repatriation provision should make certain disclosures. Additional disclosures are required in the period an enterprise completes its evaluation

The Company has adopted the disclosure requirements of FSP FAS 109-2 and is currently evaluating the effects of the Act. The Company expects to be in a position to finalize its assessment shortly after passage of technical corrections to the Act.

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 March 1, 2005, 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, 2004:

	2005	2006	2007	2008	2009	Thereafter	Total	Fair Value
Long-Term Debt:								
Variable Rate	$ 0	$ 0	$ 0	$ 0	$555,000	$ 0	$555,000	$555,000
Average Interest Rate	—	—	—	—	3.66%	—	3.66%	—
Fixed Rate	$ 0	$ 0	$ 0	$ 0	$ 0	$200,000	$200,000	$216,500
Average Interest Rate	—	—	—	—	—	8.25%	8.25%	—

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 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 March 1, 2005, 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

As of December 31, 2004, the Company held various derivative instruments. During 2004, the Company entered into natural gas and crude oil option agreements referred to as "collars." Collars are designed to establish floor and ceiling prices on anticipated future natural gas and crude oil production. The Company has designated these contracts as cash flow hedges designed to achieve a more predictable cash flow, as well as to reduce its exposure to price volatility. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The use of derivatives also involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. Currently, the Company does not expect losses due to creditworthiness of its counterparties.

The gas hedging transactions are generally settled based upon the average of the reporting settlement prices on the NYMEX for the last three trading days of a particular contract month. The oil hedging transactions are generally settled based on the average of the reporting settlement prices for West Texas Intermediate on the NYMEX for each trading day of a particular calendar month. For any particular collar transaction, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price for such transaction, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price of such transaction.

The estimated fair value of these transactions is based upon various factors that include closing exchange prices on the NYMEX, volatility and the time value of options. Further details related to the Company's hedging activities as of December 31, 2004 are as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price Floor	NYMEX Contract Price Ceiling	Fair Value of Asset/(Liability)
Natural Gas Contracts (MMBtu)(a)				
Collar Contracts:				
January 2005 - December 2005	5,475	$ 5.50	$ 8.00	$ 214,810
January 2005 - December 2005	1,825	$ 6.00	$ 9.30	$ 658,634
January 2005 - December 2005	1,825	$ 6.00	$ 9.25	$ 652,362
January 2005 - December 2006	3,650	$ 6.00	$ 9.25	$ 1,304,729
January 2006 - December 2006	5,475	$ 5.00	$ 7.50	$(2,116,689)
January 2006 - December 2006	3,650	$ 5.50	$ 8.25	$ (184,107)
January 2006 - December 2006	3,650	$ 5.75	$ 8.27	$ 182,666
Crude Oil Contracts (Barrels)				
Collar Contracts:				
January 2005 - December 2005	1,825,000	$40.00	$62.50	$ 3,891,103

(a) MMBtu means million British Thermal Units.

In February 2005, the Company entered into additional crude oil collars to establish floor and ceiling prices on anticipated future crude oil production. The Company has designated these contracts as cash flow hedges. Further details related to this hedging activity is as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price Floor	NYMEX Contract Price Ceiling
Crude Oil Contracts (Barrels)			
Collar Contracts:			
March 2005 - December 2005	1,530,000	$40.00	$62.50

ITEM 8. Financial Statements and Supplementary Data.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have completed an integrated audit of Pogo Producing Company's 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of stockholders' equity and of cash flows present fairly, in all material respects, the financial position of Pogo Producing Company and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 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 the standards of the Public Company Accounting Oversight Board (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 of financial statements 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 audits provide a reasonable basis for our opinion.

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

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PRICEWATERHOUSECOOPERS LLP

Houston, Texas
March 7, 2005

POGO PRODUCING COMPANY & SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2004	2003	2002
	(Expressed in thousands, except per share amounts)		
Revenues:			
Oil and gas	$1,308,225	$1,159,544	$750,401
Other	14,754	2,452	4,453
Total	1,322,979	1,161,996	754,854
Operating Costs and Expenses:			
Lease operating	144,473	123,098	112,663
General and administrative	69,775	61,291	49,490
Exploration	23,063	7,547	4,783
Dry hole and impairment	106,417	35,102	26,999
Depreciation, depletion and amortization	365,089	325,820	287,809
Production and other taxes	67,984	35,485	20,058
Transportation and other	21,699	25,924	12,879
Total	798,500	614,267	514,681
Operating Income	524,479	547,729	240,173
Interest:			
Charges	(29,333)	(46,360)	(57,450)
Income	2,526	1,852	1,760
Capitalized	14,216	16,531	24,033
Loss on debt extinguishment	(13,759)	(5,893)	—
Minority Interest—Dividends and costs associated with mandatorily redeemable convertible preferred securities of a subsidiary trust	—	—	(4,140)
Foreign Currency Transaction Gain (Loss)	(1,726)	1,370	435
Income Before Taxes and Cumulative Effect of Change in Accounting Principle	496,403	515,229	204,811
Income Tax Expense	(234,649)	(220,122)	(97,780)
Income Before Cumulative Effect of Change in Accounting Principle	261,754	295,107	107,031
Cumulative Effect of Change in Accounting Principle	—	(4,166)	—
Net Income	$ 261,754	$ 290,941	$107,031
Earnings (Loss) per Common Share:			
Basic			
Income before cumulative effect of change in accounting principle	$ 4.10	$ 4.72	$ 1.85
Cumulative effect of change in accounting principle	—	(0.07)	—
Net income	$ 4.10	$ 4.65	$ 1.85
Diluted			
Income before cumulative effect of change in accounting principle	$ 4.06	$ 4.60	$ 1.77
Cumulative effect of change in accounting principle	—	(0.06)	—
Net income	$ 4.06	$ 4.54	$ 1.77
Dividends per Common Share	$ 0.2125	$ 0.20	$ 0.12

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

POGO PRODUCING COMPANY & SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2004	December 31, 2003
	(Expressed in thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 86,456	$ 104,474
Current investments	135,000	74,280
Accounts receivable	140,988	116,970
Other receivables	37,229	39,497
Federal income taxes receivable	10,708	—
Inventory—product	5,062	5,951
Inventories—tubulars	17,850	7,735
Price hedge contracts	6,722	—
Other	5,395	5,448
Total current assets	445,410	354,355
Property and Equipment:		
Oil and gas, on the basis of successful efforts accounting		
Proved properties	4,931,264	3,919,138
Unevaluated properties	83,196	107,708
Other, at cost	36,492	30,046
	5,050,952	4,056,892
Accumulated depreciation, depletion, and amortization		
Oil and gas	(2,017,900)	(1,661,584)
Other	(23,858)	(19,467)
	(2,041,758)	(1,681,051)
Property and equipment, net	3,009,194	2,375,841
Other Assets:		
Deferred income tax	—	2,416
Foreign value added taxes receivable	8,471	4,188
Other	18,034	21,851
	26,505	28,455
	$ 3,481,109	$ 2,758,651

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

POGO PRODUCING COMPANY & SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (Continued)

LIABILITIES AND SHAREHOLDERS' EQUITY	December 31, 2004	December 31, 2003
	(Expressed in thousands)	
Current Liabilities:		
Accounts payable—operating activities	$ 72,228	$ 55,543
Accounts payable—investing activities	128,075	73,179
Income taxes payable	34,776	20,220
Accrued interest payable	4,550	9,950
Accrued payroll and related benefits	3,609	3,242
Deferred income tax	4,919	5,324
Other	31,862	16,126
Total current liabilities	280,019	183,584
Long-Term Debt	755,000	487,261
Deferred Income Tax	601,688	546,709
Asset Retirement Obligation	95,140	70,790
Other Liabilities and Deferred Credits	21,367	16,654
Total liabilities	1,753,214	1,304,998
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 64,580,639 and 63,813,283 shares issued, respectively	64,581	63,813
Additional capital	943,690	914,492
Retained earnings	728,723	480,576
Accumulated other comprehensive income	2,565	—
Deferred compensation	(9,954)	(3,518)
Treasury stock (55,359 shares), at cost	(1,710)	(1,710)
Total shareholders' equity	1,727,895	1,453,653
	$3,481,109	$2,758,651

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,		
	2004	2003	2002
	(Expressed in thousands)		
Cash flows from operating activities:			
Cash received from customers	$ 1,324,433	$1,180,901	$ 701,429
Operating, exploration and general and administrative expenses paid	(311,534)	(229,355)	(199,104)
Income taxes paid	(240,553)	(164,008)	(19,287)
Income taxes received	381	—	25,884
Interest paid	(30,043)	(45,527)	(55,526)
Cash received (paid) related to price hedge contracts	—	(15,037)	14,931
Value added taxes (paid) received	(4,283)	9,720	(7,708)
Other	314	7,865	5,860
Net cash provided by operating activities	738,715	744,559	466,479
Cash flows from investing activities:			
Capital expenditures	(442,475)	(335,615)	(368,466)
Purchase of properties	(189,597)	(189,083)	—
Acquisition of corporations, net of $11,970 cash acquired	(270,452)	—	—
Purchase of current investments	(269,107)	(206,585)	(67,951)
Sale of current investments	208,387	164,305	35,951
Proceeds from the sale of property and tubular stock	1,518	521	4,215
Net cash used in investing activities	(961,726)	(566,457)	(396,251)
Cash flows from financing activities:			
Borrowings under senior debt agreements	2,010,000	854,012	703,077
Payments under senior debt agreements	(1,594,000)	(875,000)	(773,080)
Redemption of debt	(157,782)	(176,578)	—
Proceeds from exercise of stock options	12,013	33,370	20,154
Payment of cash dividends on common stock	(13,607)	(12,520)	(6,895)
Payment of senior debt acquired through corporate purchase	(50,000)	—	—
Payment of preferred dividends of a subsidiary trust	—	—	(4,850)
Payment of financing issue costs and other	(3,820)	(100)	(329)
Net cash (used in) provided by financing activities	202,804	(176,816)	(61,923)
Effect of exchange rate changes on cash	2,189	739	(150)
Net increase in cash and cash equivalents	(18,018)	2,025	8,155
Cash and cash equivalents at the beginning of the year	104,474	102,449	94,294
Cash and cash equivalents at the end of the year	$ 86,456	$ 104,474	$ 102,449
Reconciliation of net income to net cash provided by operating activities:			
Net income	$ 261,754	$ 290,941	$ 107,031
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
(Gains) losses on sales	279	(386)	(3,034)
Depreciation, depletion and amortization	365,089	325,820	287,809
Dry hole and impairment	106,417	35,102	26,999
Interest capitalized	(14,216)	(16,531)	(24,033)
Price hedge contracts	(657)	8,346	17,589
Other	26,675	25,989	728
Increase (decrease) in deferred income taxes	(9,377)	51,818	70,929
Change in assets and liabilities:			
Increase in accounts receivable	(18,284)	(14,990)	(50,521)
Increase in federal income taxes receivable	(10,637)	—	—
(Increase) decrease in inventory—product	(247)	(1,422)	173
(Increase) decrease in other current assets	73	(623)	(12,571)
(Increase) decrease in other assets	(979)	11,502	(6,784)
Increase in accounts payable	12,289	14,606	6,170
Increase in income taxes payable	14,653	4,347	33,610
Decrease in accrued interest payable	(5,364)	(1,133)	(352)
Increase in accrued payroll and related benefits	369	234	343
Increase in other current liabilities	8,266	993	6,377
Increase in deferred credits	2,612	5,780	1,876
Net cash provided by operating activities	$ 738,715	$ 744,559	$ 466,479

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

POGO PRODUCING COMPANY & SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(Expressed in thousands)

	Common Stock(a)	Additional Capital	Retained Earnings (Deficit)	Accumulated Other Compre-hensive Income (Loss)	Deferred Compen-sation Restricted Stock	Treasury Stock	Share-holders' Equity	Compre-hensive Income (Loss)
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	
Issuance of restricted stock, less amortization of $412	—	—	—	—	(3,518)	—	(3,518)	
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	—	—	—	—	—	—	—	$297,190
Balance at December 31, 2003	63,813	$914,492	$480,576	$ —	$(3,518)	$(1,710)	$1,453,653	
Net income	—	—	261,754	—	—	—	261,754	$261,754
Stock option activity and other	465	16,818	—	—	—	—	17,283	
Shares issued as compensation	303	12,380	—	—	—	—	12,683	
Issuance of restricted stock, less amortization of $1,917	—	—	—	—	(6,436)	—	(6,436)	
Dividends ($0.2125 per common share)	—	—	(13,607)	—	—	—	(13,607)	
Unrealized gain arising during the year on price hedge contracts	—	—	—	2,992	—	—	2,992	
Net unrealized gains on price hedge contracts	—	—	—	(427)	—	—	(427)	2,565
Comprehensive income	—	—	—	—	—	—	—	$264,319
Balance at December 31, 2004	64,581	$943,690	$728,723	$ 2,565	$(9,954)	$(1,710)	$1,727,895	

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

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

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), Hungary and exploration activities in offshore New Zealand.

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 economic and operating conditions. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. Proved reserves do not include, for example, hydrocarbons that may be recovered from undrilled prospects or the recovery of which is otherwise subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics or economic factors. Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or through the application of fluid injection or other improved recovery techniques confirmed by a pilot project or operation of an installed program. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Proved undeveloped reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled and other undrilled units where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. The Securities and Exchange Commission provides a complete definition of proved reserves in Rule 4-10(a) of Regulation S-X.

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, 2004, the Company had taken approximately 6,094 MMcf of natural gas less than it was entitled to based on its interest in certain properties, and approximately 4,352 MMcf more than its entitlement on other properties, placing the Company in a net under-delivered position of approximately 1,742 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, 2004 consists of approximately 399,416 barrels of crude oil and condensate, net to the Company's interest, and is carried at the Company's estimated average cost of $12.67 per barrel. The product inventory at December 31, 2003 consisted of approximately 495,452 barrels of crude oil and condensate, net to the Company's interest, and is carried at its estimated average cost of $12.01 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 well costs are capitalized until the results are determined. If proved reserves are not discovered, the exploratory well costs are expensed. The following table reflects the net changes in capitalized exploratory well costs pending proved reserve determination during 2004, 2003 and 2002 (amounts expressed in thousands):

	2004	2003	2002
Balance at January 1,	$18,784	$ 33,948	$31,968
Additions to capitalized exploratory well costs pending the determination of proved reserves	10,932	63	10,993
Reclassifications to proved oil and gas properties	—	(13,047)	(9,013)
Capitalized exploratory well costs charged to expense	(6,727)	(2,180)	—
Balance at December 31,	$22,989	$ 18,784	$33,948

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of wells for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling (dollars expressed in thousands):

	2004	2003	2002
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$10,932	$ 63	$10,993
Capitalized exploratory well costs that have been capitalized for a period greater than one year	12,057	18,721	22,955
Balance at December 31,	$22,989	$18,784	$33,948
Number of exploratory wells that have costs capitalized for a period greater than one year	12	21	23

As of December 31, 2004, exploratory well costs that have been capitalized for a period greater than one year since the completion of drilling include costs of $7.9 million and $3.8 million that have been capitalized since 2001 and 2000, respectively, related to two projects.

As of December 31, 2004, more than 91% of the capitalized well costs that have been capitalized for a period greater than one year relate to the Company's Gulf of Thailand concession. It has been the Company's experience that the assignment of proved reserves in its Thailand Concession is often delayed for more than one year due to the drilling of subsequent exploratory wells and the need for a production license grant from the government of the Kingdom of Thailand. In regards to the costs capitalized at December 31, 2004, the Company continues to actively pursue government approval for additional production licenses on its Thailand concession, a process which has historically averaged approximately 3 years and has taken up to six years. To the extent such licenses are not awarded or proved reserves cannot be assigned, such costs will be charged to earnings in the period such determination is made.

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 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 when the Company believes it is more likely than not that such benefits will not 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. The Company follows the provisions of 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.

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 333,400 shares of common stock with a fair market value of $13,491,000 during the year ended December 31, 2004. 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, 2004, 2003 and 2002 (in thousands of dollars, except per share amounts):

	Year Ended December 31,		
	2004	2003	2002
Net income, as reported	$261,754	$290,941	$107,031
Add: Employee stock-based compensation expense, net of related tax effects, included in net income, as reported	3,006	1,408	756
Deduct: Total employee stock-based compensation expense, determined under fair value method for all awards, net of related tax effects	(6,759)	(7,017)	(6,466)
Net income, pro forma	$258,001	$285,332	$101,321
Earnings per share:			
Basic—as reported	$ 4.10	$ 4.65	$ 1.85
Basic—pro forma	$ 4.04	$ 4.56	$ 1.75
Diluted—as reported	$ 4.06	$ 4.54	$ 1.77
Diluted—pro forma	$ 4.01	$ 4.45	$ 1.68

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 2004, 2003 and 2002, respectively: risk free interest rates of 3.00%, 2.30% and 4.20%, expected volatility of 25.7%, 28.4% and 33.9%, dividend yields of 0.48%, 0.61% and 0.51%, and an expected life of the options of three and a half, three and seven 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.

Current Investments—

At December 31, 2004 and 2003, the Company held $135.0 million and $74.3 million, respectively, of AAA rated auction rate municipal bonds and variable rate municipal demand notes classified as available for sale securities. The Company's investments in these securities are recorded at cost, which approximates fair market value due to their variable interest rates, which typically reset every 7 to 35 days, and, despite the long-term nature of their stated contractual maturities, the Company has the ability to quickly liquidate these securities. As a result, there were no cumulative gross unrealized holding gains (losses) or gross realized gains (losses) from these current investments. All income generated from these current investments was recorded as interest income.

Revision in the Classification of Certain Securities—

In connection with the preparation of this report, the Company concluded that it was appropriate to classify our auction rate municipal bonds and variable rate municipal demand notes as current investments.

Previously, such investments had been classified as cash and cash equivalents. Accordingly, the classification in 2003 has been revised to report $74.3 million of these securities as current investments in a separate line item on the Consolidated Balance Sheet. Corresponding adjustments have also been made to the Consolidated Statement of Cash Flows for the periods ended December 31, 2003 and 2002 to reflect the gross purchases and sales of these securities as investing activities rather than as cash and cash equivalents. For the fiscal years ended December 31, 2003 and 2002 net cash used in investing activities related to these current investments of $42.3 million and $32.0 million, respectively, was previously included in cash and cash equivalents in the Consolidated Statement of Cash Flows. This change in classification does not affect previously reported cash flows from operations or from financing activities, or the previously reported Consolidated Statements of Income for any period.

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.

Treasury Stock—

On January 25, 2005, the Company announced a plan to repurchase, through open market or privately negotiated transactions, not less than $275 million nor more than $375 million of its common stock. The repurchased shares will be accounted for as treasury stock. As of March 1, 2005, the Company had completed the purchase of 940,200 shares at a total cost of $41.5 million.

Recent Accounting Pronouncements—

The Financial Accounting Standards Board ("FASB") has issued three new pronouncements relevant to the Company's accounting. These are Statement of Financial Accounting Standards No. 123 (revised 2004) ("SFAS 123R"), "Share-Based Payment", Statement of Financial Accounting Standards No. 153 ("SFAS 153"), "Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29" and FASB Staff Position FAS 109-2 ("FSP FAS 109-2"), "Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision Within the American Jobs Creation Act of 2004".

SFAS 123R. SFAS 123R will require compensation costs related to share-based payment transactions to be recognized in the financial statements. With limited exceptions, the amount of compensation cost will be measured based on the grant-date fair value of the equity or liability instruments issued. In addition, liability awards will be remeasured each reporting period. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. Statement 123(R) replaces FASB Statement No. 123 ("SFAS 123"), "Accounting for Stock-Based Compensation", and supersedes APB Opinion No. 25, "Accounting for Stock Issued to Employees". SFAS 123R is effective as of the first interim or annual reporting period that begins after June 15, 2005.

The Company currently follows the provisions of SFAS 123 and the adoption of SFAS 123R is not expected to have a material effect on the Company's financial statements.

SFAS 153. SFAS 153 was a result of an effort by the FASB and the International Accounting Standards Board ("IASB") to improve financial reporting by eliminating certain narrow differences between their existing accounting standards. One such difference was the exception from fair value measurement in APB Opinion No. 29, *Accounting for Nonmonetary Transactions*, for nonmonetary exchanges of similar productive assets. SFAS 153 replaces this exception with a general exception from fair value measurement for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. SFAS 153 will be applied prospectively and is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. Earlier application is permitted for nonmonetary asset exchanges occurring in fiscal periods beginning after the date of issuance of this Statement. The adoption of SFAS 153 is not expected to have a material effect on the Company's financial statements.

FSP FAS 109-2. In December 2004, the FASB staff issued FSP FAS 109-2 to provide accounting and disclosure guidance for the repatriation provisions included in the American Jobs Creation Act of 2004 (the "Act"). The Act introduced a special limited-time dividends received deduction on the repatriation of certain foreign earnings to a U.S. taxpayer. As a result, an issue has arisen as to whether an enterprise should be allowed additional time beyond the financial reporting period in which the Act was enacted to evaluate the effects of the Act on its plan for reinvestment or repatriation of foreign earnings for purposes of applying Statement 109. The following are the key points relevant to the Company's position:

- An enterprise is allowed additional time beyond the financial reporting period of enactment to evaluate the effect of the Act without undermining the entity's assertion that repatriation of foreign earnings is not expected within the foreseeable future.
- An enterprise should recognize the income tax effect when it decides on a plan for reinvestment or repatriation of foreign earnings. This decision may occur in stages, and each stage may occur at a different time. Also, before its plan for reinvestment or repatriation is finalized, an enterprise may decide on a range of amounts that it will repatriate. In this situation, the FSP requires recognition of the income tax effect of the lowest amount within the range.
- If an enterprise has recognized a deferred tax liability for some, or all, of its unremitted foreign earnings because it did not overcome the presumption of repatriation of foreign earnings, it should continue to presume repatriation of those earnings as well as current foreign earnings that are not expected to be indefinitely reinvested. The enterprise shall measure the income tax effects of such repatriation without the effects of the repatriation provision until it has decided on a plan for repatriation.
- An enterprise that has not yet completed its evaluation of the repatriation provision should make certain disclosures. Additional disclosures are required in the period an enterprise completes its evaluation

The Company has adopted the disclosure requirements of FSP FAS 109-2 and is currently evaluating the effects of the Act. The Company expects to be in a position to finalize its assessment shortly after passage of technical corrections to the Act.

(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, 2004		
	Income(a)	Shares	Per Share
Basic earnings per share	$261,754	63,848	$ 4.10
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	—	545	
Diluted earnings per share	$261,754	64,393	$ 4.06
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	$ —	25	$49.02

	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.

	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

(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, 2004, are as follows (expressed in thousands):

	2004	2003	2002
United States	$396,068	$364,097	$101,349
Foreign	100,335	151,132	103,462
Income before income taxes and cumulative effect of change in accounting principle	$496,403	$515,229	$204,811

The components of income tax expense (benefit) for each of the three years in the period ended December 31, 2004, are as follows (expressed in thousands):

	2004	2003	2002
Current			
United States	$147,759	$116,813	$15,497
Foreign	96,262	51,491	11,351
Deferred			
United States	3,896	26,375	32,451
Foreign	(13,268)	25,443	38,481
Income tax expense	$234,649	$220,122	$97,780

Total income tax expense for each of the three years in the period ended December 31, 2004, 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):

	2004	2003	2002
Federal statutory income tax rate	35.0%	35.0%	35.0%
Increases resulting from:			
Foreign income taxed at different rates	6.4	4.6	7.8
Recognition of valuation allowance on foreign losses	2.2	—	—
U.S. taxes on repatriation of foreign earnings.	1.1	1.9	2.3
State income taxes, net of federal benefits	1.2	0.7	0.5
Other	1.4	0.5	2.2
	47.3%	42.7%	47.8%

The principal components of the Company's deferred income tax assets and liabilities at December 31, 2004 and 2003 (expressed in thousands) are as follows:

	December 31, 2004	December 31, 2003
Deferred tax assets:		
Foreign deferred tax assets and net operating loss carry forwards	$ 12,143	$ 2,795
Valuation allowance of deferred tax assets and foreign net operating loss	(12,143)	(379)
Other	16,252	9,938
	16,252	12,354
Deferred tax liabilities:		
Book basis in excess of tax basis for oil and gas properties and equipment	(613,664)	(553,967)
Other	(9,195)	(8,004)
	(622,859)	(561,971)
Net deferred tax liability	$(606,607)	$(549,617)

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 corporations during 2004.

During 2003, the Company utilized its remaining Thailand net operating loss carryforwards to offset current year income taxes. As of December 31, 2004 the Company had $20,595,000 in net operating loss carryforwards available to offset future income tax in Hungary. Such net operating loss carryforwards do not expire. In addition, there are additional loss carryforwards of $44,606,000 that may be available pending approval of the Hungarian tax authorities

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 $122,328,000 at December 31, 2004. 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.

On October 22, 2004, the President signed the American Jobs Creation Act of 2004 (the "Act"). The Act creates a temporary incentive for U.S. corporations to repatriate accumulated income earned abroad by providing an 85% dividend received deduction for certain dividends from controlled foreign corporations. The deduction is subject to a number of limitations and, as of March 1, 2005, uncertainty remains as to how to interpret numerous provisions of the Act. As a result, the Company is not yet in a position to decide whether, and to what extent, it might repatriate foreign earnings that have not yet been remitted to the U.S. If certain technical corrections to the Act are passed, the Company may consider repatriating an amount up to $195,669,000 of the cash and current investments held by international subsidiaries as of December 31, 2004, with an associated tax liability of approximately $10.2 million (assuming 15% of such cash is subject to tax at the U.S. statutory rate).

(4) Long-Term Debt

Long-term debt at December 31, 2004 and 2003, consists of the following (dollars expressed in thousands):

	December 31, 2004	December 31, 2003
Senior debt—		
Bank revolving credit agreement:		
LIBOR based loans, borrowings at December 31, 2004 and 2003 at interest rates of 3.665% and 2.3125%, respectively	$515,000	$135,000
LIBOR Rate Advances, borrowings at December 31, 2004 at an interest rate of 3.5275%	40,000	—
Swing line money market loans, borrowings at December 31, 2003 at an interest rate of 2.375%	—	4,000
Total senior debt	555,000	139,000
Subordinated debt—		
10⅜% Senior subordinated notes, due 2009	—	150,000
8¼% Senior subordinated notes, due 2011	200,000	200,000
Total subordinated debt	200,000	350,000
Unamortized discount on 2009 Notes	—	(1,739)
Long-term debt	$755,000	$487,261

On December 16, 2004, the Company entered into a new credit agreement (the "Credit Facility") , replacing its then existing credit agreement dated as of March 8, 2001, as amended. The Credit Facility is with various financial institutions and provides for revolving credit borrowings up to a maximum principal amount of $750,000,000 at any one time outstanding, with borrowings not to exceed a borrowing base determined at least semiannually using the administrative agent's usual and customary criteria for oil and gas reserve valuation, adjusted for incurrences of other indebtedness since the last redetermination of the borrowing base. As of December 31, 2004, the borrowing base was $900,000,000. The Credit Facility provides that in specified circumstances involving an increase in ratings assigned to the Company's debt, the Company may elect for the borrowing base limitation to no longer apply to restrict available borrowings. The Credit Facility also includes procedures for additional financial institutions selected by the Company to become lenders under the agreement, or for any existing lender to increase its commitment in an amount approved by the Company and the lender, subject to a maximum of $250,000,000 for all such increases in commitments of new or existing lenders. Additionally, the Credit Facility permits short-term swing-line loans up to $10,000,000 and the issuance of letters of credit up to $75,000,000, which in each case reduce the credit available for revolving credit borrowings. All outstanding amounts owed under the Credit Facility become due and payable no later than the final maturity date of December 16, 2009, and are subject to acceleration upon the occurrence of events of default which the Company considers usual and customary for an agreement of this type, including failure to make payments under the credit agreement, non-performance of covenants and obligations continuing beyond any applicable grace period, default in the payment of other indebtedness in excess in principal amount of $25,000,000 or a default accelerating or permitting the acceleration of any such indebtedness, or the occurrence of a "change in control" of the Company, including the acquisition of beneficial ownership of in excess of 50% of its capital stock. If at any time the outstanding credit extended under the agreement exceeds the applicable borrowing base, the deficiency is required to be amortized in four monthly installments commencing 90 days after the deficiency arises, and until the deficiency is eliminated, increases in some applicable interest rate margins apply.

Borrowings under the Credit Facility bear interest, at the Company's election, at a prime rate or Eurodollar rate, plus in each case an applicable margin. In addition, a commitment fee is payable on the unused portion of each lender's commitment. The applicable interest rate margin varies from 0% to 0.25% in the case of borrowings based on the prime rate and from 1.00% to 2.00% in the case of borrowings based on the Eurodollar rate, depending on the utilization level in relation to the borrowing base and, in the case of Eurodollar borrowings, ratings assigned to the Company's debt.

The Credit Facility contains various covenants, including among others restrictions on liens, restrictions on incurring other indebtedness if a default under the credit agreement exists or would result or if a borrowing base deficiency would result, restrictions on dividends and other restricted payments if a default under the credit agreement exists or would result, restrictions on mergers, restrictions on investments, and restrictions on hedging activity of a speculative nature or with counterparties having credit ratings below specified levels. Financial covenants include a covenant not to permit the Company's ratio of consolidated debt to consolidated total capitalization (determined without reduction for any non-cash write downs after the date of the credit agreement) to exceed 60% at any time, and not to permit the Company's consolidated ratio of EBITDAX to Fixed Charges (as those terms are defined in the credit agreement) for the four most recent fiscal quarters to be less than or equal to 2.5 to 1.0 at the end of any quarter.

The Company gave notice on March 18, 2004 of its intent to redeem all $150,000,000 of its 10⅜% Senior Subordinated Notes due 2009 (the "2009 Notes") at 105.188% of their face amount. On April 19, 2004, the Company paid $157,782,000 (excluding accrued interest) in cash to holders of the 2009 Notes. The cash redemption payment was funded through borrowings under the Company's existing bank credit facility. The Company recorded a pre-tax expense on the redemption of the 2009 Notes of $10,893,000 in "Loss on debt extinguishment" during the year ended December 31, 2004.

On April 10, 2001, the Company issued $200,000,000 principal amount of 2011 Notes. The 2011 Notes bear interest at a rate of $8\frac{1}{4}\%$, 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. 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 indenture governing the 2011 Notes also imposes 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.

(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 $3,096,000 in 2004, $2,942,000 in 2003, and $2,821,000 in 2002. Expenses for the FPSO lease were approximately $10,600,000 in each of the years 2004, 2003 and 2002. Expenses for the FSO were approximately $4,000,000 in each of the years 2004, 2003 and 2002. Rental expense for other equipment was $5,497,000 in 2004, $4,241,000 in 2003 and $2,022,000 in 2002.

Future minimum lease payments related to the Company's operating leases at December 31, 2004 are approximately $23,500,000 in 2005; $23,500,000 in 2006; $20,200,000 in 2007; $16,800,000 in 2008; $9,900,000 in 2009 and $47,100,000 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:

	2004	2003	2002
		(Expressed in thousands)	
Long-Lived Assets:			
As of December 31,			
United States	$2,576,120	$1,943,564	$1,780,431
Kingdom of Thailand	433,032	420,856	378,260
Other	42	11,421	358
Total	$3,009,194	$2,375,841	$2,159,049
Capital Expenditures:			
(including interest capitalized)			
For the year ended December 31,			
United States	$ 931,444	$ 376,430	$ 269,250
Kingdom of Thailand	122,748	132,409	112,440
Other	32,033	11,485	—
Total	$1,086,225	$ 520,324	$ 381,690
Revenues:			
For the year ended December 31,			
United States	$ 987,688	$ 858,505	$ 542,014
Kingdom of Thailand	335,237	303,470	212,763
Other	54	21	77
Total	$1,322,979	$1,161,996	$ 754,854
Depreciation, depletion, and amortization expense:			
For the year ended December 31,			
United States	$ 258,467	$ 237,853	$ 221,646
Kingdom of Thailand	106,556	87,906	66,099
Other	66	61	64
Total	$ 365,089	$ 325,820	$ 287,809
Operating income (loss):			
For the year ended December 31,			
United States	$ 424,790	$ 399,678	$ 138,934
Kingdom of Thailand	147,953	151,830	103,021
Other	(48,264)	(3,779)	(1,782)
Total	$ 524,479	$ 547,729	$ 240,173

(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):

	2004	2003	2002
Shell Trading Company	$147,076	$161,451	$103,714
Pacific Petroleum and Trading Co. Ltd.	135,160	30,018	—

(8) Credit Risk

Substantially all of the Company's accounts receivable at December 31, 2004 and 2003, 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, 2004 and 2003, the Company had provided reserves for receivables from specifically identified receivables from customers and joint interest owners that are considered doubtful of collection of $3,882,000 and $3,810,000, 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 and to the effect of the recent tsunami disaster in the Kingdom. 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 $13,000 in 2004. 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 $1,360,000 to the savings plan in 2004, $1,233,000 in 2003, and $1,068,000 in 2002.

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 2005. 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 2005 are approximately $554,000.

The following table sets forth the plans' status (in thousands of dollars) as of December 31, 2004 and 2003. The Company uses a December 31 measurement date for its plans.

	Retirement Plan		Post-Retirement Medical Plan	
	2004	2003	2004	2003
Change in benefit obligation				
Benefit obligation at beginning of year	$29,519	$24,297	$ 17,145	$ 15,067
Service cost	2,631	2,248	1,385	1,102
Interest cost	1,751	1,546	1,044	915
Benefits paid	(1,302)	(340)	(356)	(338)
Actuarial loss	4,259	1,768	1,984	399
Benefit obligation at end of year	$36,858	$29,519	$ 21,202	$ 17,145
Change in plan assets				
Fair value of plan assets at beginning of year	$32,236	$26,625	$ —	$ —
Actual return on plan assets	1,729	6,234	—	—
Employer contributions	—	—	356	338
Benefits paid	(1,302)	(340)	(356)	(338)
Administrative expenses	(364)	(283)	—	—
Fair value of plan assets at end of year	$32,299	$32,236	$ —	$ —
Reconciliation of funded status				
Funded status	$ (4,559)	$ 2,717	$(21,202)	$(17,145)
Unrecognized actuarial loss	13,849	9,037	5,086	3,292
Unrecognized transition (asset) or obligation	—	—	303	608
Unrecognized prior service cost	625	671	—	—
Prepaid (accrued) benefit cost at year-end	$ 9,915	$12,425	$(15,813)	$(13,245)
Components of net periodic benefit cost				
Service cost	$ 2,631	$ 2,248	$ 1,385	$ 1,102
Interest cost	1,750	1,546	1,044	915
Expected return on plan assets	(2,639)	(2,176)	—	—
Amortization of prior service cost	46	43	—	—
Amortization of transition (asset) obligation	—	—	305	305
Amortization of net loss	722	1,040	190	64
	$ 2,510	$ 2,701	$ 2,924	$ 2,386
Accumulated benefit obligation	$28,248	$23,591		

Plan Assumptions

	Retirement Plan 2004	Retirement Plan 2003	Retirement Plan 2002	Post-Retirement Medical Plan 2004	Post-Retirement Medical Plan 2003	Post-Retirement Medical Plan 2002
Plan assumptions to determine benefit obligations						
Discount rate	5.75%	6.00%	6.50%	5.75%	6.00%	6.50%
Rate of compensation increase	5.50%	4.75%	4.75%	—	—	—
Plan assumptions to determine net cost						
Discount rate	6.00%	6.50%	7.25%	6.00%	6.50%	7.25%
Expected long-term rate of return on plan assets	8.50%	8.50%	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 2004.

Expected benefit payments for the retirement plan for the next ten years are as follows (amounts expressed in thousands):

Year Ending December 31,	Expected Benefit Payment
2005	$ 2,905
2006	3,435
2007	2,761
2008	3,442
2009	3,375
Next 5 years	19,667

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

Asset Category	Target	Actual as of December 31, 2004	Actual as of December 31, 2003
Equity securities	100%	99%	100%
Debt securities	0%	0%	0%
Real estate	0%	0%	0%
Other	0%	1%	0%
Total	100%	100%	100%

For measurement purposes related to the Company's post-retirement medical plan, a 11% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2005. The rate is assumed to decrease gradually to 5% for 2012 and remain at that level thereafter. This compares to the amounts used for 2004 measurement purposes, where a 12% 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 2004	$ 472	$ (376)
Effect on year-end 2004 postretirement benefit obligation	$3,539	$(2,868)

In December 2003, the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act) was signed into law. The Act introduced a prescription drug benefit under Medicare (Medicare Part D), as well as a nontaxable federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. In May 2004, the FASB issued Staff Position No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003" (FSP No. 106-2), which addresses the accounting and disclosure requirements associated with the effects of the Act.

The Company has elected not to reflect changes in the Act in its 2004 financial statements since the Company has concluded that the effects of the Act are not a significant event that calls for remeasurement under FAS 106.

(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 3,975,757, 2,297,657 and 2,911,565 as of December 31, 2004, 2003 and 2002, respectively. Stock options granted during and after 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
2004	303,400	$13,164,429
2003	144,000	$ 6,045,840
2002	40,065	$ 1,192,935

The number of unvested shares of restricted stock was 403,900, 157,019 and 38,621 as of December 31, 2004, 2003 and 2002, respectively.

Stock Options

A summary of the status of the Company's stock option activity as of December 31, 2004, 2003 and 2002, and changes during the years ended on those dates is presented below:

	Number of Awards	Weighted Average Exercise Price
Outstanding, December 31, 2001	3,852,580	$22.01
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
Outstanding, December 31, 2003	2,582,773	$29.16
Granted in 2004	30,000	$48.50
Exercised in 2004	(452,437)	$26.55
Canceled in 2004	(15,000)	$26.98
Outstanding, December 31, 2004	2,145,336	$30.00
Exercisable, December 31, 2004	1,553,567	$27.66
Weighted-average fair value of options granted during 2004		$10.88

The following table summarizes information about stock options outstanding at December 31, 2004

	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	50,800	1,578	$18.35	50,800	$18.35
$20.31 to $24.77	772,702	2,178	$23.33	772,702	$23.33
$25.38 to $29.78	766,834	2,701	$29.60	478,467	$29.50
$31.18 to $33.94	54,000	2,163	$32.03	40,665	$32.24
$36.00	35,000	519	$36.00	35,000	$36.00
$40.63 to $43.46	436,000	1,252	$41.87	175,933	$41.65
$45.89 to $49.48	30,000	1,590	$48.50	—	—
Total	2,145,336	2,127	$30.00	1,553,567	$27.66

(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 years ended December 31, 2004 and 2003 is as follows (in thousands):

	Year Ended December 31, 2004	Year Ended December 31, 2003
Initial ARO as of January 1,	$70,790	$63,643
Liabilities incurred during period	22,224(a)	3,001
Liabilities settled during period	(3,856)	(691)
Accretion expense	5,982	4,837
Balance of ARO as of December 31,	$95,140	$70,790

(a) $14.1 million of this amount relates to acquisitions during 2004.

For the years ended December 31, 2004 and 2003, the Company recognized depreciation expense related to its ARC of $3,017,000 and $3,850,000, respectively. 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 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 SFAS 143 been applied retroactively during the year ended December 31, 2002, 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	
	As Reported	Pro forma
Net Income	$107,031	$106,662
Earnings per share:		
Basic	$ 1.85	$ 1.84
Diluted	$ 1.77	$ 1.76

(12) Minority Interest

Pogo Trust I, a subsidiary of the Company, called for redemption of its 6½% 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 amount 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.

(13) 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.

Current Investments

Fair value is carrying value due to short term holding period.

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(s)	Fair value is carrying value as of December 31, 2004 and 2003 based on the market value interest rates.
LIBOR Rate Advances	Fair value is carrying value as of December 31, 2004 based on the market value interest rates.
2009 Notes	Fair value is 106% of carrying value as of December 31, 2003 based on quoted market value.
2011 Notes	Fair value is 108.1% and 110.6% of carrying value as of December 31, 2004 and 2003, based on quoted market value.

The carrying value and estimated fair value of the Company's financial instruments at December 31, 2004 and 2003 (in thousands of dollars) are as follows:

	2004		2003	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents	$ 86,456	$ 86,456	$ 104,474	$ 104,474
Current investments	$ 135,000	$ 135,000	$ 74,280	$ 74,280
Receivables	$ 178,217	$ 178,217	$ 156,467	$ 156,467
Payables	$(235,079)	$(235,079)	$(148,942)	$(148,942)
Debt:				
Bank revolving credit agreement loans	$(515,000)	$(515,000)	$(139,000)	$(139,000)
LIBOR Rate Advances	$ (40,000)	$ (40,000)	$ —	$ —
2009 Notes	$ —	$ —	$(148,261)	$(159,000)
2011 Notes	$(200,000)	$(216,250)	$(200,000)	$(221,250)

The Company occasionally enters into hedging contracts to minimize the impact of oil and gas price fluctuations. See Note 14 for a further discussion of these contracts.

(14) Hedging Activities

During the year ended December 31, 2004, the Company did not recognize any gains or losses from its hedging activities related to 2004 production. The Company did recognize a pre-tax gain of $657,000 due to ineffectiveness on hedge contracts during the year ended 2004. The Company recognized a pre-tax loss of $22,822,000 ($14,873,000 after taxes) for the year ended December 31, 2003 and a pre-tax gain of $3,640,000 ($2,367,000 after tax) for the year ended December 31, 2002 from its price hedge contracts, which are included in oil and gas revenues. Net unrealized gains on derivative instruments of $2,565,000, net of deferred taxes of $1,381,000, have been reflected as a component of other comprehensive income for the year ended December 31, 2004. Based on the fair market value of the hedge contracts as of December 31, 2004, the Company would reclassify additional pre-tax losses of approximately $6,722,000 (approximately $4,369,000 after taxes) from accumulated other comprehensive loss (shareholders' equity) to net income during the next twelve months.

As of December 31, 2004, the Company held various derivative instruments. During 2004, the Company entered into natural gas and crude oil option agreements referred to as "collars." Collars are designed to establish floor and ceiling prices on anticipated future natural gas and crude oil production. The Company has designated these contracts as cash flow hedges designed to achieve a more predictable cash flow, as well as to reduce its exposure to price volatility. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The use of derivatives also involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. Currently, the Company does not expect losses due to creditworthiness of its counterparties.

The gas hedging transactions are generally settled based upon the average of the reporting settlement prices on the NYMEX for the last three trading days of a particular contract month. The oil hedging transactions are generally settled based on the average of the reporting settlement prices for West Texas Intermediate on the NYMEX for each trading day of a particular calendar month. For any particular collar transaction, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price for such transaction, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price of such transaction.

The estimated fair value of these transactions is based upon various factors that include closing exchange prices on the NYMEX, volatility and the time value of options. Further details related to the Company's hedging activities as of December 31, 2004 are as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price		Fair Value of Asset/(Liability)
		Floor	Ceiling	
Natural Gas Contracts (MMBtu)(a)				
Collar Contracts:				
January 2005 - December 2005	5,475	$ 5.50	$ 8.00	$ 214,810
January 2005 - December 2005	1,825	$ 6.00	$ 9.30	$ 658,634
January 2005 - December 2005	1,825	$ 6.00	$ 9.25	$ 652,362
January 2005 - December 2006	3,650	$ 6.00	$ 9.25	$ 1,304,729
January 2006 - December 2006	5,475	$ 5.00	$ 7.50	$(2,116,689)
January 2006 - December 2006	3,650	$ 5.50	$ 8.25	$ (184,107)
January 2006 - December 2006	3,650	$ 5.75	$ 8.27	$ 182,666
Crude Oil Contracts (Barrels)				
Collar Contracts:				
January 2005 - December 2005	1,825,000	$40.00	$62.50	$ 3,891,103

(a) MMBtu means million British Thermal Units.

In February 2005, the Company entered into additional crude oil collars to establish floor and ceiling prices on anticipated future crude oil production. The Company has designated these contracts as cash flow hedges. Further details related to this hedging activity is as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price Floor	NYMEX Contract Price Ceiling
Crude Oil Contracts (Barrels)			
Collar Contracts:			
March 2005 - December 2005	1,530,000	$40.00	$62.50

(15) Acquisitions

In December 2004, the Company completed the acquisition of two privately held corporations for approximately $282.5 million in cash and a deferred payment of $26.4 million to be made in 2005 to the former owner of one of the corporations. The corporations have subsequently been named Pogo Producing (San Juan) Company and Pogo Producing (Texas Panhandle) Company (the "corporations"). The transactions included properties located primarily in the San Juan basin of New Mexico and the Texas Panhandle. The Company acquired the corporations primarily to strengthen its position in domestic natural gas properties. The corporations had an estimated 133 billion cubic feet of gas equivalent proven reserves (Bcfe) as of the dates of acquisition. The Company recorded the estimated fair values of the assets acquired and the liabilities assumed at the closing date of the transactions, which primarily consisted of oil and gas properties of $423.7 million, long term debt of $50.1 million and deferred tax liabilities of $67.4 million. No goodwill was recorded for the transactions.

In 2004, the Company also completed six other producing property acquisitions for cash consideration totaling approximately $186 million. These acquisitions added approximately 119 Bcfe to the Company's proved reserves.

Pro Forma Information

The following summary presents unaudited pro forma consolidated results of operations as if the acquisitions had occurred as of January 1, 2002. The pro forma results are for illustrative purposes only and include adjustments in addition to the pre-acquisition historical results of the corporations, 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 acquisitions been consummated at that date, nor are they necessarily indicative of future operating results.

	Year Ended December 31,		
	2004	2003	2002
	(Unaudited)		
Pro Forma:			
Revenues	$1,385,056	$1,203,236	$789,382
Income before cumulative effect of change in accounting principle	271,853	298,959	106,499
Net income	271,853	294,830	106,499
Earnings per share:			
Basic—			
Income before cumulative effect of change in accounting principle	$ 4.26	$ 4.78	$ 1.84
Net income	$ 4.26	$ 4.66	$ 1.84
Diluted—			
Income before cumulative effect of change in accounting principle	$ 4.22	$ 4.71	$ 1.76
Net income	$ 4.22	$ 4.59	$ 1.76

POGO PRODUCING COMPANY & SUBSIDIARIES
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)		
		2004		
Revenues	$ 1,308,225	$ 973,083	$ 335,142	$ —
Lease operating expense	(144,444)	(100,506)	(43,938)	—
Exploration expense	(23,063)	(21,557)	(197)	(1,309)(a)
Dry hole and impairment expense	(106,417)	(57,443)	(5,594)	(43,380)(a)
Depreciation, depletion and amortization expense	(360,569)	(255,022)	(105,547)	—
Production and other taxes	(67,984)	(44,104)	(23,880)	—
Transportation and accretion	(21,651)	(19,487)	(2,164)	—
Pretax operating results	584,097	474,964	153,822	(44,689)
Income tax (expense) benefit	(264,503)	(178,416)	(83,663)	(2,424)
Operating results	$ 319,594	$ 296,548	$ 70,159	$ (47,113)
		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)

(a) Included in Other International for 2004, 2003 and 2002 are costs associated with activities related primarily to Hungary with the exception of $5,551 of dry hole and impairment cost related to the Danish North Sea in 2004, $182 of exploration expense in 2004 related to New Zealand, and $271 of dry hole and impairment expense in 2003 related to the Company's British North Sea block that was relinquished in 2003.

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):				
2004:				
Property acquisition				
Proved	$ 608,496	$608,496	$ —	$ —
Unproved	26,707	26,707	—	—
Exploration				
Capitalized	89,673	56,533	2,018	31,122
Expensed	23,063	21,553	379	1,131
Development	340,967	226,804	113,252	911
Asset retirement cost	19,603	15,569	4,034	—
Interest	14,216	6,738	6,960	518
Total oil and gas costs incurred	$1,122,725	$962,400	$126,643	$33,682
Provision for depreciation, depletion and amortization	$ 360,569	$255,022	$105,547	$ —
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 oil and gas costs incurred	$ 383,208	$270,146	$112,984	$ 78
Provision for depreciation, depletion and amortization	$ 283,865	$218,636	$ 65,229	$ —

(a) Included in Other International for 2004 are costs associated with Hungary, the Danish North Sea and New Zealand. Included for the years 2003 and 2002 are costs associated with initial activities related almost entirely to Hungary.

(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.

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, 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
Revisions of previous estimates	4,281,792	5,012,763	(720,527)	(10,444)
Extensions, discoveries and other additions	4,197,673	1,727,761	2,469,912	—
Purchase of properties	13,775,000	13,775,000	—	—
Sale of properties	(1,832,000)	(1,832,000)	—	—
Estimated 2004 production	(18,910,000)	(12,370,000)	(6,540,000)	—
Proved Reserves as of December 31, 2004	116,382,474	83,866,054	32,516,420	—
Proved Developed Reserves as of:				
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	—
December 31, 2004	92,574,224	72,968,008	19,606,216	—

Estimates of Proved Reserves

Natural Gas (MMcf)

	Total Company	United States	Kingdom of Thailand	Other International
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)	—
Proved Reserves as of December 31, 2003	1,012,323	837,004	165,188	10,131
Revisions of previous estimates	(20,854)	(16,357)	5,634	(10,131)
Extensions, discoveries and other additions	37,648	33,610	4,038	—
Purchase of properties	172,022	172,022	—	—
Sale of properties	(2,888)	(2,888)	—	—
Estimated 2004 production	(118,581)	(89,410)	(29,171)	—
Proved Reserves as of December 31, 2004	1,079,670	933,981	145,689	—
Proved Developed Reserves as of:				
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	—
December 31, 2004	852,848	769,753	83,095	—

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 and Hungary, as noted.

	Year Ended December 31, 2004			
	Total Company	United States	Kingdom of Thailand	Hungary
		(Expressed in thousands)		
Beginning balance	$ 2,450,030	$2,009,123	$ 424,439	$ 16,468
Revisions to prior years' proved reserves:				
Net changes in prices and production costs	868,070	631,060	237,010	—
Net changes due to revisions in quantity estimates	25,232	39,661	3,739	(18,168)
Net changes in estimates of future development costs	(161,666)	(154,659)	(7,007)	—
Accretion of discount	369,000	292,866	74,482	1,652
Changes in production rate and other	(43,414)	(51,192)	7,778	—
Total revisions	1,057,222	757,736	316,002	(16,516)
New field discoveries and extensions, net of future production and development costs	212,963	126,167	86,796	—
Purchases of properties	596,173	596,173	—	—
Sales of properties	(58,570)	(58,570)	—	—
Sales of oil and gas produced, net of production costs	(1,074,146)	(808,986)	(265,160)	—
Previously estimated development costs incurred	148,290	98,135	50,155	—
Net change in income taxes	(236,395)	(161,067)	(75,376)	48
Net change in standardized measure of discounted future net cash flows	645,537	549,588	112,417	(16,468)
Ending balance	$ 3,095,567	$2,558,711	$ 536,856	$ —

POGO PRODUCING COMPANY & SUBSIDIARIES

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

	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	(70,226)	(21,781)	(48,445)	—
Accretion of discount	309,836	249,556	60,280	—
Changes in production rate and other	(194,267)	(182,172)	(12,095)	—
Total revisions	865,330	592,992	272,338	—
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	104,624	46,311	58,313	—
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

	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	(103,916)	(56,659)	(47,257)
Accretion of discount	154,066	113,035	41,031
Changes in production rate and other	16,577	60,325	(43,748)
Total revisions	1,608,211	1,416,233	191,978
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	224,980	165,374	59,606
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

POGO PRODUCING COMPANY & SUBSIDIARIES

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

	Total Company	United States	Kingdom of Thailand	Hungary
	(Expressed in thousands)			
	2004			
Future gross revenues	$10,574,504	$ 8,850,237	$1,724,267	$ —
Future production costs:				
Lease operating expense	(2,529,480)	(2,123,530)	(405,950)	—
Future development and abandonment costs	(580,701)	(437,117)	(143,584)	—
Future net cash flows before income taxes	7,464,323	6,289,590	1,174,733	—
Discount at 10% per annum	(2,892,390)	(2,650,272)	(242,118)	—
Discounted future net cash flows before income taxes	4,571,933	3,639,318	932,615	—
Future income taxes, net of discount at 10% per annum	(1,476,366)	(1,080,607)	(395,759)	—
Standardized measure of discounted future net cash flows related to proved oil and gas reserves	$ 3,095,567	$ 2,558,711	$ 536,856	$ —
	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	—
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	$ —

Quarterly Results—Unaudited

Summaries of the Company's results of operations by quarter for the years 2004 and 2003 are as follows:

	Quarter Ended			
	Mar. 31	June 30	Sept. 30	Dec. 31
	(Expressed in thousands, except per share amounts)			
2004				
Revenues	$307,882	$326,893	$364,197	$324,007
Gross profit(a)	$150,911	$152,403	$173,775	$117,165
Net income	$ 71,640	$ 65,189	$ 86,612	$ 38,313
Earnings per share(b):				
Basic	$ 1.13	$ 1.02	$ 1.36	$ 0.60
Diluted	$ 1.12	$ 1.01	$ 1.35	$ 0.59
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

(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.***

None.

ITEM 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

The Company has established disclosure controls and procedures to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to the officers who certify the Company's financial reports and to other members of senior management and the Board of Directors.

Based on their evaluation as of December 31, 2004, the Company's Chairman, President and Chief Executive Officer and its Senior Vice President and Chief Financial Officer have concluded that the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) are effective to ensure that the information required to be disclosed by the Company in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

Management's Report on Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of the Company's management, including the Chairman, President and Chief Executive Officer and its Senior Vice President and Chief Financial Officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Company's evaluation under the framework in *Internal Control—Integrated Framework,* the Company's management concluded that its internal control over financial reporting was effective as of December 31, 2004. The Company's managements assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Controls

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.

ITEM 9B. *Other Information*

There is no information required to be disclosed on Form 8-K for the quarter ended December 31, 2004 that has not been previously reported.

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 26, 2005, to be filed within 120 days of December 31, 2004 pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended (the Company's "2005 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 2005 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 2005 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 2005 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 2005 Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. ***Exhibits and Financial Statement Schedules.***

(a) Documents Filed as Part of this Form 10-K

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, as filed on April 28, 2004 (Exhibit 3.1, Quarterly Report on Form 10-Q for the quarter ended March 31, 2004, File No. 1-7796).
*3.2	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 December 16, 2004 among Pogo Producing Company, as the Borrower, certain commercial lending institutions, as the Lenders, Bank of Montreal, acting through its Chicago, Illinois branch, as the Administrative Agent for the Lenders, Bank of America, N.A., Toronto Dominion (Texas) LLC and BNP Paribas, as Co-Syndication Agents, Wachovia Bank, National Association, as Documentation Agent, and Citibank, N.A. and the Bank of Nova Scotia, as Managing Agents (Exhibit 4.1, Current Report on Form 8-K filed December 22, 2004, File No. 1-7792).
*4.2	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).
*4.3	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).
*4.4	Amendment to Rights Agreement dated as of April 26, 2004 between Pogo Producing Company and Computershare Investor Services, L.L.C., as successor Rights Agent (Exhibit 99.2, Current Report on Form 8-K filed April 29, 2004, 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	Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Paul G. Van Wagenen, dated February 1, 2005.
10.9	Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Stephen R. Brunner, dated February 1, 2005.
10.10	Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Jerry A. Cooper, dated February 1, 2005.
10.11	Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and John O. McCoy, Jr., dated February 1, 2005.
10.12	Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and David R. Beathard, dated February 1, 2005.
10.13	Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Radford P. Laney, dated February 1, 2005.
10.14	Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and J. Don McGregor, dated February 1, 2005.
10.15	Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Gerald A. Morton, dated February 1, 2005.
10.16	Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and James P. Ulm, II, dated February 1, 2005.
10.17	Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Barry W. Acomb, dated February 1, 2005.
10.18	Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Bruce E. Archinal, dated February 1, 2005.
10.19	Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Michael J. Killelea, dated February 1, 2005.
*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, 2003, 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, 2003, 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 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 PricewaterhouseCoopers LLP
23.2	Consent of Ryder Scott Company, L.P.
23.3	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, 2004.
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. for the year ended December 31, 2004.
99.2	Summary Report of Miller and Lents, Ltd. for the year ended December 31, 2004.
*99.3	Summary Report of Ryder Scott Company, L.P. for the year ended December 31, 2003 (Exhibit 99.1, Annual Report on Form 10-K for the year ended December 31, 2003).
*99.4	Summary Report of Miller and Lents, Ltd. for the year ended December 31, 2003 (Exhibit 99.2, Annual Report on Form 10-K for the year ended December 31, 2003).
99.5	Summary Report of Ryder Scott Company, L.P. for the year ended December 31, 2002.
99.6	Summary Report of Miller and Lents, Ltd. for the year ended December 31, 2002.

* Asterisk indicates exhibits incorporated by reference as shown.

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: March 7, 2005

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 March 2, 2005.

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 **William L. Fisher**	Director
/s/ THOMAS A. FRY, III **Thomas A. Fry, III**	Director
/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*	

Non-GAAP to GAAP Reconciliation

Discretionary Cash Flow to Operating Cash Flow Reconciliation (Figure D), as shown on page 5 of Pogo's 2004 Annual Report

Discretionary cash flow is presented because of its wide acceptance as a financial indicator of a company's ability to internally fund exploration and development activities and to service or incur debt. This measure is widely used by investors and professional research analysts in the valuation, comparison, rating and investment recommendations of companies within the oil and gas exploration and production industry. Management also views the non-GAAP measure of discretionary cash flow as a useful tool for comparisons of the Company's financial indicators with those of peer companies that follow the full cost method of accounting. Discretionary cash flow is a financial measure that is not calculated in accordance with generally accepted accounting principles ("GAAP") and should not be considered as an alternative to net cash provided by operating activities, as defined by GAAP, or as a measure of financial performance or liquidity under GAAP. The Company defines discretionary cash flow as net cash provided by operating activities before changes in operating assets and liabilities and exploration expenses. Other companies may define discretionary cash flow differently. A reconciliation to net cash provided by operating activities is as follows:

	1999	2000	2001	2002	2003	2004
Net cash provided by operating activities	$ 68,757	$ 239,059	$ 368,076	$ 466,479	$ 744,559	$ 738,715
Remove changes in operating assets and liabilities	7,051	61,764	(14,120)	21,679	(19,294)	(2,751)
Add back exploration expenses	5,982	15,291	23,373	4,783	7,547	23,063
Discretionary cash flow	$ 81,790	$ 316,114	$ 377,329	$ 492,941	$ 732,812	$ 759,027

Certifications

Pogo submitted to the New York Stock Exchange during 2004 a certification of its Chief Executive Officer regarding compliance with the Exchange's corporate governance listing standards. Pogo also included as exhibits to its Annual Report on Form 10-K for the year ended December 31, 2004 filed with the Securities and Exchange Commission the certifications of its Chief Executive Officer and Chief Financial Officer required under Section 302 of the Sarbanes-Oxley Act of 2002.

Publications

Pogo will make available to any shareholder, without charge, copies of its Annual Report on Form 10-K as filed with the Securities and Exchange Commission. For copies of this or any Pogo publication, please contact:

Pogo Producing Company
Investor Relations Department
P.O. Box 2504
Houston, TX 77252-2504
713.297.5000

Anyone interested in the company's reports, news releases, presentations and other materials also can find such documents, request copies and sign up for email alerts through our website, **www.pogoproducing.com**.

ANNUAL MEETING

The annual meeting of shareholders of Pogo Producing Company will be held in Midland, Texas, April 26, 2005, at 10:30 a.m., CDT at the Petroleum Club of Midland, 501 West Wall Street, Midland, Texas 79701. Notice of the meeting and proxy statement will be sent to shareholders of record as of March 11, 2005.

CORPORATE ADDRESS

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(713) 297-5000
www.pogoproducing.com

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P.O. Box 10340
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THAIPO LIMITED

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All Seasons Place
87 Wireless Road
Khwaeng Lumpini, Khet Patumwam
Bangkok 10330, Thailand
011-662-654-0686

POGO HUNGARY LTD.

1054 Budapest
Kalman Imre U.1.
Hungary
011-361-475-1390

COMMON STOCK

The following table shows the range of low and high prices of Pogo's common stock on the New York Stock Exchange, Inc. composite tape using the symbol PPP. Pogo's common stock is also listed on The Pacific Exchange.

2004	Low	High
First Quarter	39.25	50.45
Second Quarter	44.85	51.34
Third Quarter	41.19	49.71
Fourth Quarter	43.35	51.33

2003	Low	High
First Quarter	34.29	39.98
Second Quarter	38.68	45.41
Third Quarter	40.30	46.42
Fourth Quarter	41.63	49.50

Cash dividends of $0.05 per share were paid in the first, second and third quarters of 2004. During the fourth quarter of 2004, Pogo increased its cash dividend to $0.0625 per share. As of February 1, 2005, there were 2,118 holders of record of Pogo's common stock.

TRANSFER AGENT AND REGISTRAR

Computershare Investor Services, L.L.C.
Chicago, IL.

OFFICERS

Paul G. Van Wagenen
Chairman
President and Chief Executive Officer

Stephen R. Brunner
Executive Vice President - Operations

Jerry A. Cooper
Executive Vice President and
Regional Manager - Western United States

John O. McCoy, Jr.
Executive Vice President and
Chief Administrative Officer

David R. Beathard
Senior Vice President - Engineering

R. Phillip Laney
Senior Vice President and
Manager of Worldwide New Ventures

J. D. McGregor
Senior Vice President - Sales

Gerald A. Morton
Senior Vice President and
Regional Manager - Asia and Pacific

James P. Ulm, II
Senior Vice President and
Chief Financial Officer

Larry W. Acomb
Vice President and
Regional Manager - Gulf of Mexico

Bruce E. Archinal
Vice President and
Regional Manager - Gulf Coast

Frank Davis III
Vice President - Land

Thomas E. Hart
Vice President and
Chief Accounting Officer

Michael J. Killelea
Vice President and General Counsel

Robert C. Marlowe
Vice President – Accounting

Ted E. McElroy
Vice President – Tax

Jerel W. Pierce
Vice President and
Regional Manager - Europe

Leah D. Smith
Vice President - Acquisitions

DIRECTORS

Jerry M. Armstrong
Rancher; Retired Senior Partner and
Oil and Gas Division Head for a major public
accounting firm

Robert H. Campbell
Managing Director, and Director of
Public Finance of the North Pacific Region,
Lehman Brothers, Inc.

William L. Fisher
Barrow Chair and Geological Sciences Professor,
and Director of Jackson School of Geosciences
University of Texas at Austin

Thomas A. Fry III
President, National Ocean Industries Association

Gerrit W. Gong
Assistant to the President of Brigham Young
University for Planning and Assessment;
Senior Associate of Center for Strategic
and International Studies

Carroll W. Suggs
Former Chairman and CEO, Petroleum
Helicopters, Inc.; Past Chairman, National
Ocean Industries Association

Paul G. Van Wagenen
Chairman
President and Chief Executive Officer
Pogo Producing Company

Stephen A. Wells
President, Wells Resources, Inc.

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POGO PRODUCING COMPANY

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