POGO PRODUCING CO
Form 10-K
March 02, 2006

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

x	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the fiscal year ended December 31, 2005** **OR**
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number: 1-7792

Pogo Producing Company

(Exact name of registrant as specified in its charter)

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

(713) 297-5000

(Registrant s telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, $1.00 par value per share	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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes o No x

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. Large accelerated filer x Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

As of June 30, 2005, the aggregate market value of the registrant s common stock held by non-affiliates of the registrant was approximately $3,200,000,000 based on the closing sale price as reported on the New York Stock Exchange.

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

Class	**Outstanding at February 24, 2006**
Common Stock, $1.00 par value per share	57,961,147 shares

DOCUMENTS INCORPORATED BY REFERENCE

Document	Parts Into Which Incorporated
Portions of the Registrant s Proxy Statement for our Annual Meeting of Stockholders to be held April 25, 2006	Part III

FORWARD LOOKING STATEMENTS

The statements included or incorporated by reference in this Annual Report on Form 10-K for the year ended December 31, 2005 (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 Pogo Producing Company s (the Company) forward-looking statements by the words anticipate, estimate, expect, objective, projection, forecast, goal, and similar expressions. Such forward-looki statements include, without limitation, statements regarding expected production volumes, drilling of wells and related expenditures and other statements herein and therein regarding the timing of future events regarding the operations of 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 factors set forth below, the risk factors described under the caption Risk Factors 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 and integrate 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
- covenant restrictions in the Company s debt agreements

Many of these 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 primarily located in North America, both onshore and offshore, and in New Zealand. As of December 31, 2005, the Company owned approximately 3,885,000 gross leasehold acres in major oil and gas provinces in North America and approximately 1,044,000 gross acres in New Zealand. Over the last several years, the Company has transitioned from a predominately offshore-focused company to one with a majority of its reserves located in the onshore regions of North America. As of December 31, 2005, approximately 86% of the Company s reserves are located onshore.

The Company organizes its exploration and production activities principally into five operating regions, as well as a New Ventures Group and an Unconventional Resources Group. The operating regions are its Canadian Operations, 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; its Gulf of Mexico Region, which is responsible for the Company s operations offshore Texas and Louisiana in the Gulf of Mexico; and the Asia and Pacific Region, which has responsibility for the Company s operations in New Zealand. The Company s New Ventures Group is primarily responsible for identifying new projects and opportunities for the Company outside the United States and the Unconventional Resources Group is responsible for identifying new unconventional resource opportunities in North America.

On August 17, 2005, the Company closed the sale of its Thailand properties for approximately $820 million. On September 27, 2005, the Company completed the acquisition of Northrock Resources, Ltd. (Northrock) for approximately $1.7 billion. Northrock s activities are concentrated in Saskatchewan and Alberta with key exploration plays in Canada s Northwest Territories, British Columbia and the Alberta Foothills.

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 Texas Panhandle. The Company conducts its onshore operations in the United States directly and through its wholly-owned subsidiaries. Domestic onshore reserves as of December 31, 2005, accounted for approximately 54% of the Company s total proved reserves, with the Gulf Coast Region and the Western U.S. Region contributing approximately 15% and 39%, respectively, of the Company s total proved reserves. During 2005, approximately 79% of the Company s natural gas production and 38% of its oil and condensate production was from its domestic onshore properties, contributing approximately 60% of the Company s consolidated oil and gas revenues.

Exploration and Development

The Company s onshore capital and exploration expenditures for 2005 were approximately $251,400,000 (excluding approximately $59,500,000 of net property acquisitions). Comparable expenditures for 2004 and 2003 were approximately $196,500,000 (excluding approximately $489,600,000 of net property acquisitions) and $142,400,000 (excluding approximately $177,700,000 of net property acquisitions), respectively. The increase in the Company s onshore capital and exploration expenditures for 2005, compared to 2004, resulted primarily from expenditures related to increased exploratory and development drilling. The Company has currently budgeted approximately $430,000,000 for capital and exploration expenditures during 2006 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 26 years and, during this period, has participated in the discovery or development of over 41 oil and gas fields. In 2005, the Company participated in the drilling of 143 wells in these areas (96% 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 2006, the Company plans to drill approximately six exploratory wells and 104 development wells in various known fields and exploratory prospects located in southeast New Mexico, West Texas and the Texas Panhandle. Drilling objectives for these wells range in vertical depth from 3,500 feet to 18,000 feet below the surface and target numerous formations including, among others, the Brown Dolomite, Canyon, Delaware (Brushy Canyon), Spraberry, Bone Spring, Wolfcamp, Granite Wash, Strawn, Atoka and Morrow formations.

The Company also plans to continue an active development drilling program in the San Juan Basin, which is located in northwest New Mexico. Nineteen wells are expected to be drilled in multiple prospects in this area during 2006. The primary targets are the Fruitland Coal and Mesaverde formations. Drilling depths are expected to range from approximately 1,500 feet to 6,500 feet.

The Company also continues to actively participate in the exploration and development of the Madden Field 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 have historically been found from approximately 5,500 feet to 11,000 feet below the surface). Also in progress is a Frontier exploratory test well with a projected total depth of 20,585 feet.

An active Rocky Mountain drilling program of approximately 64 wells is anticipated for 2006. 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 targeting the Lower Fort Union and Lance formations at total depths ranging from 8,000 feet to 10,000 feet.

During 2005, the Company s Western U.S. Region acquired, in several transactions, proved producing properties located in southeast New Mexico, West Texas and the Texas Panhandle to complement its existing asset base. The aggregate purchase price for these transactions was approximately $46 million.

Gulf Coast Region. The Company s Gulf Coast Region is actively exploring for, acquiring and developing oil and gas reserves, primarily in the coastal onshore areas of Louisiana and Texas. Other areas of activity include the East Texas Basin and the Illinois Basin in southern Indiana. During 2005, the Gulf Coast Region participated in drilling 19 wells, 95% of which were successfully completed. For 2006, the Company has budgeted to participate in 21 exploratory wells and 45 development wells.

The Company s Gulf Coast Region was active during 2005 drilling 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 the Wilcox formation, found at depths ranging from 7,000 to 14,000 feet below the surface. At its Los Mogotes Field, the Company drilled 10 wells in 2005. There were 49 locations identified to drill at Los Mogotes at the beginning of 2006 and 25 of those are currently budgeted to be drilled. Currently, five wells are scheduled to be drilled in South Hundido and Hundido Field in 2006. Elsewhere in South Texas, the Company operated and successfully completed an appraisal gas well offsetting the 2004 South Rosita Prospect discovery well in Duval County, Texas. Additional development drilling is planned for this prospect during 2006. The Company also intends to actively explore various portions of the Vicksburg and Wilcox trends of Texas during 2006.

In East Texas, the Company s Gulf Coast Region is exploring the Woodbine and Austin Chalk Formations for new oil and gas reserves in Polk and Tyler Counties. The Company acquired 128 square miles of new, proprietary 3-D seismic data in 2005 and interpretation of that data has yielded a number of exploratory prospects which are 100% owned and operated by the Company. The Company controls approximately 80,000 acres in this area.

During 2005, the Company s Gulf Coast Region participated in drilling two Miocene exploratory wells in South Louisiana. For 2006 in South Louisiana, the Company has agreed to participate in the drilling of three outside-operated exploratory wells. In addition, the Company will operate four exploratory tests in this area in 2006. The Company also plans to operate and begin to acquire 100-plus square miles of new 3-D seismic in central South Louisiana.

In October 2005, the Company obtained a 50% working interest in an unconventional resource play in southwest Indiana that an industry partner operates. Approximately 225,000 gross acres have been leased, seven horizontal New Albany Shale gas wells have been drilled and gas from a production pilot comprised of four of those wells is being produced and sold. Five exploratory wells and an additional 5 to 15 development wells are contemplated for 2006.

Domestic Offshore Operations

Gulf of Mexico Region. Approximately 14% of the Company s proved reserves as of December 31, 2005 were located in the Gulf of Mexico. During 2005, approximately 14% of the Company s natural gas production and 50% of its oil and condensate production from the Company s domestic offshore properties contributed approximately 30% 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 Company s domestic offshore capital and exploration expenditures for 2005 were $88,700,000. Comparable expenditures for 2004 and 2003 were approximately $150,300,000 and $60,500,000, respectively. The decrease in the Company s domestic offshore capital and exploration expenditures for 2005, compared with 2004, resulted primarily from decreased expenditures for exploration and development wells and facilities construction. During 2005, the Company invested approximately $71,200,000 in exploration and development wells and $11,600,000 in facilities construction for its Gulf of

Mexico operations. The Company has currently budgeted approximately $91,000,000 for capital and exploration expenditures during 2006 in the Gulf of Mexico, of which $63,600,000 is budgeted for exploration and development wells and $23,300,000 for facilities construction. The Company participated in drilling seven wells during 2005 in the Gulf of Mexico Region, two of which were considered successful. At December 31, 2005, 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 56 of the 88 offshore leases in which it had an interest as of December 31, 2005.

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.

Hurricanes Katrina and Rita

On August 29, 2005, after passing through the Gulf of Mexico, Hurricane Katrina made landfall near New Orleans, Louisiana and caused one of the worst natural disasters in U.S. history. On September 24, 2005, Hurricane Rita, one of the strongest measured hurricanes to have entered the Gulf of Mexico, made landfall between Sabine Pass, Texas and Johnson s Bayou, Louisiana. Due to the hurricanes, substantially all of the Company s Gulf of Mexico production was shut-in and most has been restored incrementally since then. As of February 1, 2006, approximately 4,000 Bbls of oil and 20 MMcf of natural gas of the Company s net daily production remain shut-in as a result of the storms. One of the platforms the Company operates, located in Main Pass Block 123, sustained major damage, and significant damage to platforms, plants and pipelines operated by others also occurred, including facilities that are located in Viosca Knoll Block 823, Eugene Island Block 330, and South Marsh Island Block 128. The Company expects remaining shut-in production to come back on-line by the end of the first quarter of 2007. The Company maintains business interruption insurance on some of its blocks in the Gulf of Mexico. Coverage commenced 60 days after the blocks were shut in and continues for a period of one year thereafter, unless the production is fully restored earlier. There is no assurance that recoveries under the policy will be sufficient to cover the cash flow the Company would have otherwise generated from the affected properties.

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, 2005, the Company owned interests in 76 federal leases and 12 state leases offshore Louisiana and Texas. Federal leases generally have primary terms of five, eight or ten years, depending on water depth, and state leases generally have terms of three or five years, depending on location, in each case subject to extension by development and production operations.

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 acreage in Canada and New Zealand. The Company s explorationists continue to evaluate other international opportunities that are consistent with its exploration strategy and expertise. For a discussion of certain risks associated with the Company s international operations, see Risk Factors The Company s foreign operations subject it to additional risks, The Company s integration of Northrock may not be successful and The Company may not be able to obtain sufficient drilling equipment and experienced personnel to conduct its operations.

Exploration and Development

The Company s international capital and exploration expenditures were approximately $162,000,000 (excluding approximately $2,526,000,000 of property acquisitions and approximately $71,095,000 of expenditures related to discontinued Thailand and Hungary operations) for 2005. Expenditures for 2004 and 2003 were approximately $148,900,000 (approximately $5,700,000 excluding Thailand and Hungary operations) and $138,000,000 (approximately $67,000 excluding Thailand and Hungary operations), respectively. The increase in the Company s capital and exploration expenditures for 2005 resulted primarily from expenditures for facilities costs and increased drilling activity.

The Company has currently budgeted approximately $204,000,000 for capital and exploration expenditures during 2006 in areas outside the United States, including approximately $200,000,000 in Canada.

Canadian Operations

The Company s Canadian operations are conducted through Northrock, a wholly-owned subsidiary of the Company. Northrock is headquartered in Calgary, Alberta, Canada, and has field offices in Rocky Mountain House, Alberta, Grande Prairie, Alberta and in Estevan, Saskatchewan. Northrock conducts its activities through joint ventures with other oil and gas companies and operates its properties using field personnel and independent contractors.

Northrock s principal producing properties are located in the Canadian provinces of Alberta, Saskatchewan and British Columbia. In addition, Northrock participates in an active exploration program in the Northwest Territories.

Crude oil and natural gas reserves in Canada, as of December 31, 2005, accounted for approximately 32% of the Company s total proved reserves. During the fourth quarter of 2005, Northrock contributed approximately 27% of the Company s natural gas production and 41% of its oil and condensate production.

Exploration and Development

Since the acquisition by the Company, Northrock has significantly expanded its existing exploration and development program, spending $78.1 million in the fourth quarter of 2005. During that time, Northrock drilled 43 wells, of which 39 wells were successfully completed. For 2006, Northrock will initiate a very active exploration and development program and expects to spend approximately $200 million to drill 184 wells, including 33 exploratory wells.

The exploration and development program in Canada will focus on various known fields in Alberta and Saskatchewan. In 2006, significant drilling activity is planned on recent exploration success in both southern Alberta and in southeast Saskatchewan. In addition to initiatives in Alberta and Saskatchewan, Northrock has an average 32% interest in an exploration project in the Mackenzie Delta in the Northwest Territories near the route of the proposed Mackenzie Valley Gas Pipeline. Since the acquisition, Northrock has participated in drilling two wells in the Mackenzie Delta and is expected to participate in the drilling of two additional wells in the first quarter of 2006.

Acquisitions

Northrock also has an active acquisition program focused on acquiring properties to complement existing initiatives or on new areas with anticipated significant development opportunities.

In the fourth quarter of 2005, Northrock spent $41.5 million on corporate acquisitions and to acquire interests in producing properties located primarily in southern Alberta and in southwest Saskatchewan. For 2006, the Company anticipates that Northrock will continue to pursue incremental acquisition opportunities to supplement its exploration and development program.

Asia and Pacific Region

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 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 seismic data acquisition and 2-D seismic data reprocessing. The 3-D seismic data acquired by the Company has been processed and is being analyzed with a goal of committing to drill multiple exploration wells in 2007, subject to rig availability. The Company has a commitment to drill one well on each of the three licenses by February 2008 or relinquish the license. Production permits of up to 40 years may be applied for if a commercial field is discovered.

Vietnam. The Company, together with a joint venture partner, has been notified that it was the high bidder on Block 124, which covers approximately 1.48 million acres offshore along the coast of Vietnam. As of year end, the Company was negotiating with PetroVietnam, the state oil company of Vietnam, for a Production Sharing Contract covering Block 124.

Thailand and Hungary Dispositions

On August 17, 2005, the Company completed the sale of all of the issued and outstanding shares of Thaipo Limited, a Thailand company and a wholly-owned subsidiary of the Company (Thaipo), and all of the Company s 46.34% interest in B8/32 Partners Limited, also a Thailand company (B8/32 Partners), for a total purchase price of $820 million. The sale of the shares of Thaipo and the Company s interests in B8/32 Partners effected the disposition of all of the Company s Thailand operations. The Company s Thailand concession consisted of approximately 608,000 acres in the central portions of the Gulf of Thailand. The Company recognized an after tax gain of approximately $403 million on the sale of the Thailand assets for 2005.

On June 7, 2005, the Company completed the sale of Pogo Hungary Ltd. (Pogo Hungary) for approximately $9 million. The sale of Pogo Hungary resulted in the disposition of the Company s exploration license and related operations in Hungary. The Hungary license consisted of approximately 778,000 acres. The Company recognized an after tax gain of approximately $5 million on the sale of Pogo Hungary for 2005.

Both the Thailand and Hungary assets have been treated as discontinued operations. For further discussion, please refer to Management s Discussion and Analysis of Financial Condition and Results of Operations.

Geographic and Other Information

For financial information about geographic areas, see Note 8 Geographic Segment Information in the Notes to Consolidated Financial Statements, which is incorporated herein by reference. For a presentation of the Company s revenues, net income and total assets for the years ended December 31, 2005, 2004 and 2003, respectively, see Financial Statements and Supplementary Data.

The business of exploration, development and production of crude oil and natural gas is capital intensive. The Company has historically needed and will continue to need substantial amounts of cash to fund its capital expenditure and working capital requirements. For further discussion, see Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources and Risk Factors The Company has substantial capital requirements.

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. The Company also owns an approximate 15% interest in the Lost Cabin Gas Plant located in the Madden Field, which currently is processing in excess of 340 MMcf 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.

Most of the Company s domestic 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. Domestic 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.

Northrock, the Company s wholly-owned Canadian subsidiary, currently sells the majority of its oil production under contracts with a six-month term but with prices based on monthly market conditions. The remainder of Northrock s crude oil production is sold in the spot market for no more than one month at a time at then currently available prices. The majority of Northrock s gas sales are month-to-month spot market sales at currently available prices. Approximately 60% of Northrock s spot market, month-to-month sales of natural gas are sold under firm delivery requirements for the month of sales. The remaining approximate 40% of sales are sold under a best efforts basis. The Company believes that this 60-40 mix affords it the necessary flexibility in its production to meet all firm delivery requirements. A small portion of Northrock s gas sales are under longer-term contracts but with prices based on monthly market conditions and best efforts delivery obligations.

Other than oil and natural gas forward sales contracts that may exist from time to time, which are described below in Miscellaneous; Competition and Market Conditions, and the natural gas 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 2005, crude oil sales to Shell Trading Company constituted more than 10% of the Company s consolidated revenues.

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. See Risk Factors The Company faces significant competition and is smaller than many of its competitors. 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 Agreement.

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. 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, 2005, the Company was a party to certain natural gas or crude oil option contracts (see Quantitative and Qualitative Disclosures About Market Risk 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.

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, 2005:

	Developed Acreage(a)		Undeveloped Acreage(b)	
	Gross	Net	Gross	Net
Domestic Onshore				
Louisiana	15,614	4,629	59,400	52,861
New Mexico	81,816	64,600	86,156	65,334
Texas	236,072	134,421	213,767	132,578
Indiana	2,240	1,120	222,760	111,380
Wyoming	30,886	3,894	133,746	98,475
Utah			64,217	61,830
Other	15,959	8,739		
Total Domestic Onshore	382,587	217,403	780,046	522,458
Domestic Offshore				
Louisiana	138,456	59,412	180,355	157,256
Texas	11,520	5,286	5,760	2,880
Total Domestic Offshore	149,976	64,698	186,115	160,136
Total Domestic	532,563	282,101	966,161	682,594
International				
Canada	621,701	292,383	1,764,848	946,267
New Zealand			1,043,806	1,043,806
Total International	621,701	292,383	2,808,654	1,990,073
Total Company	1,154,264	574,484	3,774,815	2,672,667

(a) Developed acreage consists of lease acres spaced or assignable to 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.

(b) Approximately 2% of the Company s total onshore net undeveloped acreage is under leases that have minimum terms expiring in 2006. Approximately 0.7% of the Company s total offshore net undeveloped acreage have expiring terms in 2006.

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.

	2005	2004	2003
Average Production (Lifting) Costs per Mcfe(a):			
Located in the United States	$ 1.45	$ 0.97	$ 0.68
Located in Canada	$ 1.47		
Total Company(b)	$ 1.45	$ 0.97	$ 0.68

(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.

(b) Total Company average production costs exclude discontinued operations.

Productive Wells and Drilling Activity

The following table shows the Company s interest in productive oil and natural gas wells as of December 31, 2005. For purposes of this table productive wells are defined as wells producing hydrocarbons and wells capable of production (i.e., 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 that have located commercial quantities of oil or natural gas but that are not capable of commercial production without the installation of material production facilities or that, 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
Domestic Onshore	**1,512**	**910.0**	**1,626**	**917.7**	**3,138**	**1,827.7**
Operated	874	804.6	976	801.2	1,850	1,605.8
Nonoperated	638	105.4	650	116.5	1,288	221.9
Offshore	**120**	**58.0**	**55**	**26.9**	**175**	**84.9**
Operated	45	38.5	32	21.2	77	59.7
Nonoperated	75	19.5	23	5.7	98	25.2
Canada	**1,077**	**529.7**	**670**	**322.4**	**1,747**	**852.1**
Operated	325	265.3	281	229.4	606	494.7
Nonoperated	752	264.4	389	93.0	1,141	357.4
Total	**2,709**	**1,497.7**	**2,351**	**1,267.0**	**5,060**	**2,764.7**
Operated	1,244	1,108.4	1,289	1,051.8	2,533	2,160.2
Nonoperated	1,465	389.3	1,062	215.2	2,527	604.5

(a) One or more completions in the same bore hole are counted as one well. The data in the above table includes 48 gross (31.3 net) oil wells and 143 gross (8.5 net) natural gas wells with multiple completions.

(b) The Company was in the process of drilling a total of 48 gross (11 Canada, 37 U.S.) and 27.1 net (7.5 Canada, 19.6 U.S.) oil and natural gas wells as of December 31, 2005.

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 indicate 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.

	2005		**2004**		**2003**	
	Productive	**Dry**	**Productive**	**Dry**	**Productive**	**Dry**
Gross Wells:						
Onshore United States						
Exploratory	10	3	1	5	9	3
Development	204	12	248	9	169	9
Offshore United States						
Exploratory	2	5	2	2	5	2
Development			8		3	
Canada						
Exploratory	2	1				
Development	37	3				
Total	255	24	259	16	186	14
Net Wells:						
Onshore United States						
Exploratory	7.7	2.2	0.6	3.8	5.9	2.0
Development	70.2	5.1	122.4	4.6	75.9	3.5
Offshore United States						
Exploratory	2.0	3.9	1.6	1.8	2.3	2.0
Development			6.2		2.2	
Canada						
Exploratory	1.5	1.0				
Development	21.9	1.9				
Total	103.3	14.1	130.8	10.2	86.3	7.5

Reserves

The following table sets forth information as to the Company s net proved and proved developed reserves as of December 31, 2005, 2004 and 2003, 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 (PV-10), as set forth in reports prepared by Ryder Scott Company L.P. (Ryder Scott) and reports prepared by the Company and reviewed by Ryder Scott Company Canada (Ryder Scott Canada) and Miller and Lents, Ltd. (Miller and Lents), in accordance with criteria prescribed by the Commission. The summary reports of Ryder Scott, Ryder Scott Canada, 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 the Company s Canadian areas, which are covered by the Ryder Scott Canada report, and certain domestic onshore areas on the Texas/Louisiana Gulf Coast and in Wyoming, which are covered by the Miller and Lents report. Reserves attributable to the Company s operations in Thailand and Hungary, operations that were disposed of in 2005 and are accounted for in the Company s financial statements as discontinued operations, are excluded from the table below and separately presented in the footnotes that follow the table.

	As of December 31, 2005	2004	2003
Total Proved Reserves(a):			
Oil, condensate and natural gas liquids (MBbls)			
Located in the United States	82,238	83,866	77,553
Located in Canada	61,803		
Total Company	144,041	83,866	77,553
Natural Gas (MMcf)			
Located in the United States	891,298	933,981	837,004
Located in Canada	286,427		
Total Company	1,177,725	933,981	837,004
Present value of estimated future net revenues, before income taxes (in thousands)			
Located in the United States	$ 4,666,472	$ 3,639,318	$ 2,928,663
Located in Canada	$ 1,954,086		
Total Company	$ 6,620,558	$ 3,639,318	$ 2,928,663
Total Proved Developed Reserves(b):			
Oil, condensate and natural gas liquids (MBbls)			
Located in the United States	63,161	72,968	67,391
Located in Canada	55,413		
Total Company	118,574	72,968	67,391
Natural Gas (MMcf)			
Located in the United States	685,301	769,753	702,836
Located in Canada	220,704		
Total Company	906,005	769,753	702,836
Present value of estimated future net revenues, before income taxes (in thousands)			
Located in the United States	$ 3,660,148	$ 3,122,860	$ 2,455,495
Located in Canada	$ 1,653,299		
Total Company	$ 5,313,447	$ 3,122,860	$ 2,455,495

(a) Excludes proved reserves located in Thailand and Hungary, as well as the present value of estimated future net revenues from such reserves. As of December 31, 2004 and 2003, the Company s proved reserves in Thailand consisted of 32,517 MBbls and 37,307 MBbls of oil, condensate and natural gas liquids, respectively, and 145,689 MMcf and 165,188 MMcf of natural gas, respectively. As of December 31, 2003, the Company s proved reserves in Hungary consisted of 10,131 MMcf of natural gas. The Company had no proved reserves in Hungary as of December 31, 2004 and no proved reserves in Hungary of oil, condensate and natural gas liquids as of December 31, 2003.

(b) Excludes proved developed reserves located in Thailand and Hungary, as well as the present value of estimated future net revenues from such reserves. As of December 31, 2004 and 2003, the Company s proved developed reserves in Thailand consisted of 19,607 MBbls and 19,878 MMBbls of oil, condensate and natural gas liquids, respectively, and 83,095 MMcf and 77,938 MMcf of natural gas, respectively. The Company had no proved developed reserves in Hungary as of December 31, 2004 or December 31, 2003.

The following table presents a reconciliation of the PV-10 values set forth above for both proved and proved developed reserves to the most directly comparable GAAP financial measure, which is the standardized measure of discounted future net cash flows. Management believes that presentation of PV-10 values is relevant and useful to the Company s investors because it presents the discounted future net cash flows attributable to both the Company s proved and proved developed reserves prior to taking into account the effect of the non-property related expense of estimated future income taxes. Because many factors that are unique to individual companies may impact the amount of future income taxes to be paid, the use of a pre-tax measure such as PV-10 provides greater comparability for investors when evaluating companies. Accordingly, investors may utilize the measure as a basis for comparison of the relative size and value of the Company s reserves to other companies. Management also uses the PV-10 measure when assessing the potential return on investment related to the Company s oil and gas properties. PV-10 is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP. For the Company s presentation of the standardized measure of discounted future net cash flows, please see Standardized Measure of Discounted Future Net Cash Flows Related to Proved Oil and Gas Reserves Unaudited following the notes to the consolidated financial statements in this report.

Present Value GAAP to Non-GAAP Reconciliation

	As of December 31, 2005 (thousands)	**2004**	**2003**
Present value of estimated future net revenues, before income taxes, of proved developed reserves	$ 5,313,447	$ 3,122,860	$ 2,455,495
Present value of estimated future net revenues, before income taxes, of proved undeveloped reserves	1,307,111	516,447	473,168
Present value of estimated future net revenues, before income taxes, of total proved reserves	$ 6,620,558	$ 3,639,307	$ 2,928,663
Future income taxes, net of discount at 10% per annum	(2,057,713)	(1,080,607)	(919,540)
Standardized measure of discounted future net cash flows related to proved oil and gas reserves	$ 4,562,845	$ 2,558,700	$ 2,009,123

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The PV-10 measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of the Company s natural gas and oil 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. Essentially all of the Company s natural gas production is currently sold on the spot market.

Natural gas liquids comprised approximately 14.3% of the Company s total proved liquids reserves and approximately 13.4% of the Company s proved developed liquids reserves as of December 31, 2005. 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.

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 provided by the Company to Ryder Scott Canada and Miller and Lents were as follows:

	As of December 31,		
	2005	**2004**	**2003**
Initial Weighted Average Price (in Dollars):			
Oil, condensate and natural gas liquids (per Bbl)			
Located in the United States	$ 57.06	$ 40.82	$ 31.34
Located in Canada(a)	$ 42.86		
Natural Gas (per Mcf)			
Located in the United States	$ 8.15	$ 6.04	$ 5.70
Located in Canada	$ 9.02		

(a) The difference in initial weighted prices presented for Canada and the United States are primarily due to the medium gravity crude produced from the southwest Saskatchewan assets, which account for approximately 40% of the Canadian crude oil and condensate production.

In computing future revenues from gas reserves attributable to the Company s interests, prices in effect at December 31, 2005 were used, including current market prices, contract prices and fixed and determinable price escalations where applicable. 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 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 interests, prices in effect at December 31, 2005 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 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 2005. 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, Ryder Scott Canada, and Miller and 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. 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, 2005, 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

Domestic and Foreign Tax

The Company s domestic and foreign operations are significantly affected by political developments and changes in federal, provincial, state and local tax laws and regulations.

American Jobs Creation Act of 2004

The American Jobs Creation Act of 2004 (the Act) created a temporary tax 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. In 2005, the Company adopted a Domestic Reinvestment Plan that qualifies for the temporary incentive, provided that repatriated funds are invested pursuant to the plan. The Company repatriated $497 million (the maximum amount that qualified for the dividend received deduction under the Act) during September of 2005.

Environmental Matters

The Company s operations are subject to numerous foreign, federal, state and local environmental laws and regulations governing the release and/or discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies issue regulations to implement and enforce these laws, for which compliance is often costly and difficult. The violation of these laws and regulations may result in the denial or revocation of permits, issuance of corrective action orders, assessment of administrative and civil penalties, and even criminal prosecution. The Company believes it is in substantial compliance with applicable environmental laws and regulations. Further, the Company does not anticipate that compliance with existing environmental laws and regulations will have a material effect on its financial condition or results of operations. However, there can be no assurance that substantial costs for compliance will not be incurred in the future. Moreover, it is possible that other developments, such as the adoption of stricter environmental laws, regulations, and enforcement policies, could result in additional costs or liabilities that the Company cannot currently quantify.

The Company generates wastes, including hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes or Canadian laws. The U.S. Environmental Protection Agency (the EPA), and state agencies have limited the approved methods of disposal for some types of hazardous and nonhazardous wastes. Some wastes handled by the Company in its field service activities that currently are exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes under RCRA or other applicable statutes. If this were to occur, the Company would become subject to more rigorous and costly operating and disposal requirements.

The federal Comprehensive Environmental Response, Compensation, and Liability Act, CERCLA or the Superfund law, and comparable state statutes and Canadian laws impose liability, without regard to fault or legality of the original conduct, on classes of persons that are considered to have contributed to the release of a hazardous substance into the environment. Under CERCLA, liable persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. The Company currently owns interests in or operates numerous properties and facilities that for many years have been used for industrial activities, including oil and gas production operations. Hazardous substances, wastes, or hydrocarbons may have been released on or under the properties owned or leased by the Company, or on or under other locations where such substances have been taken for disposal. In addition, some of these properties have been operated by third parties or by previous owners whose treatment and disposal or release of hazardous substances, wastes, or hydrocarbons, was not under the Company s control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, the Company could be required to remove previously disposed substances and wastes (including substances disposed of or released by prior owners or operators), remediate contaminated property (including groundwater contamination, whether from prior owners or operators or other historic activities or spills), or perform remedial plugging or pit closure operations to prevent future contamination. These laws and regulations may also expose the Company to liability for its acts that were in compliance with applicable laws at the time the acts were performed. 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 also result in the Department of the Interior requiring lessees under federal leases to suspend or cease operation in the affected area.

The Federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws and Canadian laws impose restrictions and strict controls regarding the discharge of pollutants into state waters or waters of the United States and Canada. The discharge of pollutants into jurisdictional waters is prohibited unless the discharge is permitted by the EPA or applicable state agencies. The Company has numerous applications pending before the EPA for National Pollutant Discharge Elimination System (NPDES) water discharge permits with respect to offshore drilling and production operations.

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.

Some of the Company s operations also result in emissions of regulated air pollutants. The federal Clean Air Act and analogous state laws and Canadian laws require permits for facilities that have the potential to emit substances into the atmosphere that could adversely affect environmental quality. Failure to comply with these requirements could result in the imposition of substantial administrative, civil and even criminal penalties.

The Company is also subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state statutes as well as Canadian provincial and local laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and the public.

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called greenhouse gases. Northrock s exploration and production facilities and other operations and activities may emit greenhouse gases that may subject Northrock to legislation regulating emissions of greenhouse gases. The Government of Canada has put forward a Climate Change Plan for Canada, which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. Future federal legislation, together with provincial emission reduction requirements such as those proposed in Alberta s Bill 37: Climate Change and Emissions Management, may require the reduction of emissions or emissions intensity produced by a corporation s operations and facilities. Given the uncertainties regarding implementation of the Kyoto Protocol and related climate change policies, the potential liability associated with future regulations is currently unknown. The Company can provide no assurances that the direct or indirect costs of such regulations will not materially adversely affect the business of Northrock.

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 2005, the Company incurred capital expenditures of approximately $1,297,000 for environmental control facilities, primarily relating to the cost of installing environmental equipment, the installation of pit and firewall spill liners, and routine site restoration costs. The Company has budgeted approximately $2,600,000 for expenditures involving environmental control facilities during 2006, 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, land tenure 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 Minerals Management Service (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.

FERC regulates the rates, terms and conditions applicable to the transportation of natural gas by interstate pipelines and to the storage of gas transported in interstate commerce. FERC generally requires cost-based rates, although under certain circumstances it approves market-based rates and other alternative rate mechanisms. State agencies are generally responsible for regulating intrastate gas transportation and storage. Gathering services are exempt from FERC regulation except in certain circumstances where the services are provided in connection with interstate transportation. State agencies typically have authority to regulate rates for gathering services provided within the respective states. To the extent FERC and the state agencies allow higher rates for transportation, storage, or gathering, gas prices received by the Company for the sale of its gas production may be adversely impacted. However, the impact should not be substantially different on the Company than it will be on other similar situated gas producers and sellers.

FERC also regulates the rates for interstate pipeline transportation of crude oil, while state agencies regulate rates for intrastate crude oil transportation. The transportation rates set by FERC and the state agencies can affect the prices received by the Company for the sale of its crude oil production. However, as in the case of gas transportation regulation, the impact of such rate regulation should not be substantially different on the Company than it will be on other similarly situated crude oil producers and sellers.

The provincial governments in Canada each impose lessor royalties on Crown mineral leases, and these are set by regulation. For leases where the lessor is not the provincial government, the royalty rate is negotiated between lessor and lessee.

Employees

As of December 31, 2005, the Company and its subsidiaries had 421 full-time employees, including 168 in its Calgary 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 1A. *Risk Factors.*

Natural gas and oil prices fluctuate widely, and low prices could have a material adverse impact on the Company s business.

The Company s revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil. Oil and natural gas market prices have historically been seasonal, cyclical and volatile. The average prices that the Company has recently received for its production are significantly higher than their historic average. A future drop in oil and natural gas prices could have a material adverse effect on the Company s cash flow and profitability. A sustained period of low prices could have a material adverse effect on the Company s operations and financial condition and could also result in a reduction in funds available under the Company s credit facility and associated prepayments. Lower prices may also reduce the amount of natural gas and oil that the Company can economically produce.

Among the factors that can cause oil and natural gas price fluctuation are:

- the level of consumer product demand;
- weather conditions;
- domestic and foreign governmental regulations;
- the price and availability of alternative fuels;
- political conditions in natural gas and oil producing regions;
- the domestic and foreign supply of natural gas and oil, including the decisions of the Organization of Petroleum Exporting Countries relating to export quotas and its ability to maintain oil price and production controls;
- the price of foreign imports; and
- overall economic conditions.

The Company s integration of Northrock may not be successful.

The acquisition of Northrock in September, 2005 is the largest acquisition in the Company s history. The Company may not be able to realize anticipated economic, operational and other benefits from the acquisition due to the following risks and difficulties, among others:

- Northrock s properties may not produce revenues, earnings or cash flow at anticipated levels;
- the Company may have exposure to unanticipated liabilities and costs as a result of the acquisition, some of which may materially exceed the Company s estimates;
- the Company may lose key employees on whom management is substantially dependent in the operation of Northrock s assets;
- the Company may lose customers, suppliers, partners and agents of Northrock;
- the Company may experience material difficulties and additional costs in continuing to integrate Northrock s operations, systems and personnel with those of the Company.

Please see The Company will continue to pursue acquisitions and dispositions, below.

The natural gas and oil business involves many operating risks that can cause substantial losses or hinder marketing efforts.

Numerous risks affect the Company s drilling activities, including the risk of drilling non-productive wells or dry holes. The cost of drilling, completing and operating wells and of installing production facilities and pipelines is often uncertain. Also, the Company s drilling operations could diminish or cease because of any of the following:

- title problems;
- weather conditions;
- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of underground natural gas, oil and formation water;
- natural disasters;
- pipe or cement failures;
- casing collapses;
- embedded oilfield drilling and service tools;
- abnormally pressured formations;
- environmental hazards such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases;
- noncompliance with governmental requirements; or

- shortages or delays in the delivery or availability of material, equipment or fabrication yards.

Offshore operations are also subject to a variety of operating risks related to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These hazards may interrupt production and can cause substantial losses to the Company due to injury or loss of life, severe damage to facilities, or pollution or other environmental damage. As a result, the Company could incur substantial liabilities that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions. Information regarding the impact of Hurricanes Katrina and Rita on the Company s operations, please read Business: Domestic Offshore Operations.

Moreover, effective marketing of the Company s natural gas production depends on a number of factors, such as the following:

- existing market supply of and demand for natural gas;
- the proximity of the Company s reserves to pipelines;
- the available capacity of such pipelines; and
- government regulations.

The marketing of oil and natural gas production similarly depends on the availability of pipelines and other transportation, processing and refining facilities, and the existence of adequate markets. As a result, even if hydrocarbons are discovered in commercial quantities, a substantial period of time may elapse before commercial production commences. If pipeline facilities in an area are insufficient, the Company may have to wait for the construction or expansion of pipeline capacity before the Company can market production from that area.

The Company may not be able to obtain sufficient drilling equipment and experienced personnel to conduct its operations.

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. The market for oilfield services is currently very competitive. This may lead to difficulty and delays in consistently obtaining services and equipment from vendors, obtaining drilling rigs and other equipment at favorable rates, and scheduling equipment fabrication at factories and fabrication yards. Obtaining drilling rigs for our New Zealand operations is presently difficult. This, in turn, may lead to projects being delayed or experiencing increased costs.

The Company s foreign operations subject it to additional risks.

The Company s ownership and operations in Canada, New Zealand, Vietnam and any other foreign areas where it does business are subject to the various risks inherent in foreign operations. These risks may include the following:

- currency restrictions and exchange rate fluctuations;
- risks of increases in taxes and governmental royalties and renegotiation of contracts with governmental entities; and
- changes in laws and policies governing operations of foreign-based companies.

United States laws and policies on foreign trade, taxation and investment may also adversely affect the Company s international operations. In addition, if a dispute arises from foreign operations, foreign courts may have exclusive jurisdiction over the dispute, or the Company may not be able to subject foreign persons to the jurisdiction of United States courts.

Local laws and customs in many countries differ significantly from those in the United States. In many foreign countries, particularly in those with developing economies like Vietnam, it is common to engage in business practices that are prohibited by United States regulations applicable to the Company. The U.S.

Foreign Corrupt Practices Act prohibits corporations and individuals, including the Company and its employees, from engaging in certain activities to obtain or retain business or to influence a person working in an official capacity. Although the Company has implemented policies and procedures designed to ensure compliance with these laws, there can be no assurance that all of the Company s employees, contractors and agents, including those based in or from countries where practices which violate such United States laws may be customary, will not take actions in violation of the Company s policies. Any such violation, even if prohibited by the Company s policies, could have a material adverse effect on the Company s business. In addition, the Company s foreign competitors that are not subject to the U.S. Foreign Corrupt Practices Act or similar laws may be able to secure business or other preferential treatment in such countries by means that such laws prohibit with respect to the Company.

The Company cannot control the activities on properties it does not operate; operators of those properties may act in ways that are not in the Company s best interests.

Other companies operate a portion of the oil and natural gas properties in which the Company has an interest. As a result, the Company has limited influence over operations on some of those properties or their associated costs. The Company s limited influence on non-operated properties could result in the following:

- the operator may initiate exploration or development projects on a different schedule than the Company prefers;
- the operator may propose to drill more wells or build more facilities on a project than the Company has funds for, which may mean that the Company cannot participate in those projects or share in revenues from those projects; and
- if the operator refuses to initiate an exploration or development project, the Company may not be able to pursue the project.

Any of these events could significantly affect the Company s anticipated exploration and development activities and the economic value of those properties to the Company.

Maintaining reserves and revenues in the future depends on successful exploration and development activities and/or acquisitions.

The Company must continually explore for and develop or acquire new oil and natural gas reserves to replace those produced and sold. The Company s hydrocarbon reserves and revenues will decline if the Company is not successful in its drilling, exploration or acquisition activities. Although the Company has historically maintained its reserves base primarily through successful exploration and development operations, its future efforts may not be similarly successful.

The Company s operations are subject to casualty risks against which it cannot fully insure.

The Company s operations are subject to inherent casualty risks such as blowouts, fires, explosions, cratering, uncontrollable flows of oil, natural gas or well fluids, pollution and other environmental risks, marine hazards and natural disasters. If any such event occurred, the Company could be subject to substantial financial losses due to personal injury, property damage, environmental discharge, or suspension of operations. The impact on the Company of one of these events could be significant. Although the Company purchases insurance at levels it believes to be customary for a company of its size in its industry, the Company is not fully insured against all risks incident to its business. For some risks, the Company may not obtain insurance if it believes the cost of available insurance is excessive relative to the risks presented. For example, escalating costs for business interruption insurance may lead the Company to reduce or eliminate its business interruption coverage. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect the Company s operations and financial condition. Moreover, there is no assurance that recoveries for insured events will be sufficient to cover cash flow that the Company would have otherwise generated from affected properties.

The Company has substantial capital requirements.

The Company requires substantial capital to replace its reserves and generate sufficient cash flow to meet its financial obligations. If the Company cannot generate sufficient cash flow from operations or raise funds externally in the amounts and at the times needed, it may not be able to replace its reserves or meet its financial obligations. The Company recently paid approximately $1.7 billion in cash to acquire Northrock. The Company s ongoing capital requirements consist primarily of the following items:

- funding its 2006 capital and exploration budget of $725 million;
- other allocations for acquisition, development, production, exploration and abandonment of oil and natural gas reserves;
- future dividends and stock repurchases.

The Company plans to finance anticipated ongoing expenses and capital requirements with funds generated from the following resources:

- available cash and cash investments;
- cash provided by operating activities;
- funds available under the Company s credit facility;
- the Company s uncommitted bank line(s) of credit; and
- capital the Company believes it can raise through opportunistic debt and equity offerings.

However, the Company financed a substantial part of the Northrock acquisition utilizing cash on hand and public debt issuance. In addition, the Company utilized borrowings under its credit facility related to the acquisition, thereby reducing the availability of those resources for other capital requirements. Moreover, the uncertainties and risks associated with future performance and revenues, as described in these Risk Factors, will ultimately determine the Company s liquidity and ability to meet anticipated capital requirements.

The Company will continue to pursue acquisitions and dispositions.

The Company will continue to seek opportunities to generate value through business combinations, purchases and sales of assets. The Company examines potential transactions on a regular basis, depending on market conditions, available opportunities and other factors. In addition, the Company competes with other companies in pursuing acquisitions, many of which have greater financial and other resources to acquire attractive companies and properties. Dispositions of portions of the Company s existing business or properties would be intended to result in the realization of immediate value but would consequently result in lower cash flows over the longer term, unless the proceeds are reinvested in more productive assets. The successful acquisition of oil and gas 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, and the Company s review and assessment of potential acquisitions 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. Furthermore, the Company may not be entitled to contractual indemnification for certain liabilities, or it may acquire the properties on an as is, where is basis. For a discussion of additional risks associated with the Northrock acquisition, see The Company s Acquisition of Northrock may not be successful, above.

The Company s reserve data are estimates and should not be unduly relied on.

No one can measure underground accumulations of oil and natural gas in an exact way. Projecting future production rates and the timing and amount of development expenditures is also an uncertain process. Accuracy of reserve estimates depends on the quality of available data and on economic, engineering and geological interpretation and judgment. As a result, reserve estimates often differ from the quantities of oil and natural gas ultimately recovered. To estimate economically recoverable reserves, various assumptions are made regarding future oil and natural gas prices, production levels and operating and development costs that may prove incorrect. Any significant variance from those assumptions could greatly affect estimates of economically recoverable reserves and future net revenues.

It should not be assumed that the present value of future net cash flows from the Company s proven reserves is the current value of the estimated natural gas and oil reserves. Estimates of discounted future net cash flows from proven reserves are based on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in net present value estimates, and future net present value estimates using then-current prices and costs may be significantly less than current estimates.

The Company faces significant competition and is smaller than many of its competitors.

The oil and gas industry is highly competitive. The Company competes with major and independent oil and natural gas companies for property acquisitions and for the equipment and labor required to operate and develop properties. Many of the Company s competitors have substantially greater financial and other resources. As a result, those competitors may be better able to withstand sustained periods of unsuccessful drilling. In addition, larger competitors may be able to absorb the burden of any changes in applicable laws and regulations more easily than the Company can, which would adversely affect the Company s competitive position. These competitors may also be able to pay more for exploratory prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than the Company can. The Company s ability to explore for oil and natural gas prospects and to acquire additional properties in the future will depend on its ability to conduct operations and to evaluate and select suitable properties and transactions in this highly competitive environment. Moreover, the oil and natural gas industry itself competes with other industries in supplying the energy and fuel needs of industrial, commercial and other consumers. Increased competition causing oversupply or depressed prices could greatly affect the Company s operational revenues.

The Company s competitors may use superior technology.

The Company s industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As the Company s competitors use or develop new technologies, the Company may be placed at a competitive disadvantage, and competitive pressures may force the Company to implement new technologies at a substantial cost. In addition, the Company s competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Company can. The Company cannot be certain that it will be able to implement technologies on a timely basis or at a cost that is acceptable to it. One or more of the technologies that the Company currently uses or that it may implement in the future may become obsolete, and the Company may be adversely affected.

The Company is subject to legal limitations that may adversely affect the cost, manner or feasibility of doing business.

The Company and its subsidiaries are subject to extensive domestic and foreign laws and regulations on taxation, exploration and development, and environmental and safety matters in countries where it owns or operates properties. These laws and regulations are under continuing review for amendment or expansion, and the Company could be forced to expend significant resources to comply with new laws or regulations or changes to existing requirements. Many laws and regulations require drilling permits and govern the spacing of wells, the prevention of waste, rates of production and other matters. These statutes and regulations, and any others that are passed by the jurisdictions where the Company has production could limit the total number of wells drilled or the total allowable production from successful wells, which could limit revenues. Noncompliance with these statutes or failure to establish exemptions from regulations could also result in substantial penalties, require the posting of substantial surety bonds, or in the suspension or termination of the Company s operations.

The Company is subject to various environmental liabilities.

The Company could incur liability to governments or third parties for any unlawful discharge of oil, natural gas or other pollutants into the air, soil or water, including responsibility for remedial costs. The Company s onshore and offshore operations could potentially discharge oil or natural gas into the environment in any of the following ways:

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

Environmental discharges may move through soil to water supplies or adjoining properties, giving rise to additional liabilities. Some laws and regulations could impose liability for failure to notify the proper authorities of a discharge and other failures to comply with those laws. Environmental laws may also affect the Company s costs to acquire properties. The Company does not believe that its environmental risks are materially different from those of comparable companies in the oil and gas industry. However, there is no assurance that environmental laws will not, in the future, result in decreased production, substantially increased operational costs or other adverse effects to the Company s combined operations and financial condition. Pollution and similar environmental risks generally are not fully insurable.

Derivative instruments expose the Company to risks of financial loss in a variety of circumstances.

The Company uses derivative instruments in an effort to reduce its exposure to fluctuations in the prices of oil and natural gas. The Company s derivative instruments expose it to risks of financial loss in a variety of circumstances, including when:

- a counterparty to the Company s derivative instruments is unable to satisfy its obligations;
- production is delayed or less than expected; or
- there is an adverse change in the expected differential between the underlying price in the derivative instrument and actual prices received for the Company s production.

Derivative instruments also may limit the Company s ability to realize increased revenue from increases in the prices for oil and natural gas.

The Company follows the provisions of Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, which generally requires the Company to record each hedging transaction as an asset or liability measured at its fair value. Each quarter, the Company must record changes in the fair value of its hedges, which could result in significant fluctuations in net income and stockholders equity from period to period.

The Company is subject to restrictive debt covenants.

Covenants in the credit facility and the indentures governing the Company s senior subordinated notes impose significant operating and financial restrictions on it, including the maintenance of specified financial ratios. These restrictions may adversely affect the Company s ability to finance its future operations and capital needs, to react to changes in its business or industry or to pursue available business opportunities. If certain events of default occurred under these debt instruments, the Company s outstanding indebtedness thereunder may be accelerated, and its assets may not be sufficient to repay such indebtedness. Moreover, any new indebtedness that the Company incurs may impose similar or more restrictive covenants on the Company.

ITEM 1B. *Unresolved Staff Comments.*

None.

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 Regulations; 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, 2005.

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, 2005, 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	59	1991
Stephen R. Brunner	Executive Vice President Operations	47	2002
Jerry A. Cooper	Executive Vice President and Regional Manager Western United States	57	2002
John O. McCoy, Jr.	Executive Vice President and Chief Administrative Officer	54	2002
David R. Beathard	Senior Vice President Engineering	47	2002
Michael J. Killelea	Senior Vice President, General Counsel and Corporate Secretary	43	2005
James P. Ulm, II	Senior Vice President and Chief Financial Officer	42	2002
Thomas E. Hart	Vice President and Chief Accounting Officer	62	1999

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 from 1997 - 2002; Mr. Cooper, who joined the Company in 1979, served as Senior Vice President and Western Division Manager from 1998 - 2002; Mr. McCoy, who joined the Company in 1978, served as Senior Vice President from 1998 - 2002 and has served as Chief Administrative Officer since 1989; Mr. Beathard, who joined the Company in 1982, served as Vice President Engineering from 1997 - 2002; Mr. Killelea who joined the Company in 2000, served as Vice President from 2001 - 2005, and has served as Corporate Secretary and General Counsel since 2004 and 2000, respectively; Mr. Ulm, who joined the Company in 1999, served as Vice President from 1999 - 2002, and has served as Chief Financial Officer since 1999; and Mr. Hart, who joined the Company in 1977, has served as Vice President and Chief Accounting Officer since 1999.

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
2005		
1st Quarter	$ 41.59	$ 53.30
2nd Quarter	$ 43.38	$ 54.53
3rd Quarter	$ 51.59	$ 59.69
4th Quarter	$ 48.04	$ 59.52
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, 2006, there were 2,006 holders of record of the Company s 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. In 2005, the Company paid four quarterly dividends of $0.0625 per share on its Common Stock. On January 24, 2006, the Company s quarterly dividend was increased by 20% to $0.075 per share on its Common Stock. The declaration and payment of future dividends, and the amount of such dividends, will depend upon, among other things, the Company s future earnings and financial condition, liquidity and capital requirements, the general economic and regulatory climate and other factors deemed relevant by the Company s Board of Directors.

The Company s revolving credit facility (the Facility), under which the Company has borrowed funds, and the Indentures relating to the Company s 8.250% Senior Subordinated Notes due 2011 (the 2011 Notes), 6.625% Senior Subordinated Notes due 2015 (the 2015 Notes) and 6.875% Senior Subordinated Notes due 2017 (the 2017 Notes) contain covenants that may restrict the ability of the Company to pay future dividends on the Company s Common Stock. For further discussion of the covenants, see Note 4, Long Term Debt to the Consolidated Financial Statements in this report. The Company does not believe that any of these agreements will restrict the Company s ability to pay dividends on its Common Stock in the reasonably foreseeable future.

No equity securities of the Company not registered under the Securities Act of 1933 were sold by the Company during the year ended December 31, 2005.

The following table sets forth certain information with respect to repurchases of the Company s equity securities during the three months ended December 31, 2005:

Period	Total Number of Shares Purchased(a)	Average Price Paid per Share	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plan
Oct 1 - 31 2005	1,245,000	$ 55.23	$ 52,758,953
Nov 1 - 30 2005	300,000	$ 49.28	$ 37,963,821
Dec 1 - 31 2005	455,000	$ 49.42	$ 15,458,779
Total	2,000,000		

(a) All of these shares were purchased under the plan announced on January 25, 2005.

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

In the following table, the Company s financial, production and other data for 2005 reflect the Company s acquisition of Northrock Resources from and on September 27, 2005. The Company s results for all periods presented reflect its oil and gas exploration, development and production activities in the Kingdom of Thailand and Hungary as discontinued operations. 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,				
	2005	2004	2003	2002	2001
	(Expressed in thousands, except per share and production data)				
Financial Data					
Revenues:					
Crude oil and condensate	$ 468,274	$ 417,093	$ 426,395	$ 281,990	$ 132,933
Natural gas	695,462	512,598	397,303	231,301	267,678
Natural gas liquids	52,511	43,392	32,376	24,426	12,461
Oil and gas revenues	1,216,247	973,083	856,074	537,717	413,072
Other	9,452	3,472	2,431	4,359	13,970
Total	$ 1,225,699	$ 976,555	$ 858,505	$ 542,076	$ 427,042
Income from continuing operations before cumulative effect of change in accounting principle	$ 290,069	$ 249,035	$ 235,235	$ 68,647	$ 26,260
Income from discontinued operations, net of tax	460,634 (a)	12,719	59,872	38,384	61,694
Cumulative effect of change in accounting principle			(4,166)(b)		
Net income	$ 750,703	$ 261,754	$ 290,941	$ 107,031	$ 87,954
Per share data:					
Basic income from operations before cumulative effect of change in accounting principle					
From continuing operations	$ 4.80	$ 3.90	$ 3.76	$ 1.18	$ 0.51
From discontinued operations	7.63	0.20	0.96	0.67	1.21
Basic income from operations before cumulative effect of change in accounting principle	$ 12.43	$ 4.10	$ 4.72	$ 1.85	$ 1.72
Diluted income from operations before cumulative effect of change in accounting principle					
From continuing operations	$ 4.76	$ 3.87	$ 3.67	$ 1.16	$ 0.51
From discontinued operations	7.56	0.19	0.93	0.61	1.11
Diluted income from operations before cumulative effect of change in accounting principle	$ 12.32	$ 4.06	$ 4.60	$ 1.77	$ 1.62
Cash dividends on common stock	$ 0.2500	$ 0.2125	$ 0.20	$ 0.12	$ 0.12
Price range of common stock:					
High	$ 59.69	$ 51.34	$ 49.50	$ 39.28	$ 34.50
Low	$ 41.59	$ 39.25	$ 34.29	$ 23.00	$ 20.45
Basic weighted average number of common shares outstanding	60,372	63,848	62,538	57,963	51,031
Long-term debt at year end	$ 1,643,452	$ 755,000	$ 487,261	$ 722,903	$ 792,561
Minority interest at year end	$	$	$	$	$ 145,086
Shareholders equity at year end	$ 2,098,582	$ 1,727,895	$ 1,453,653	$ 1,077,784	$ 824,885
Total assets at year end	$ 5,675,748	$ 3,481,109	$ 2,758,651	$ 2,491,593	$ 2,423,979
Production (Sales) Data					
Net daily average production and weighted average price:					
Natural gas (Mcf per day)	250,200	244,300	210,400	201,300	172,800
Price (per Mcf)	$ 7.62	$ 5.73	$ 5.17	$ 3.15	$ 4.25
Crude oil and condensate (Bbl per day)	25,734	29,530	40,173	30,971	14,804
Price (per Bbl)	$ 49.85	$ 38.59	$ 29.08	$ 24.95	$ 24.60
Natural gas liquids (Bbl per day)	4,162	4,220	4,109	4,480	2,118
Price (per Bbl)	$ 34.56	$ 28.09	$ 21.59	$ 14.94	$ 16.12

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	For the Year Ended December 31, 2005 (Expressed in thousands)	2004	2003	2002	2001
Capital Expenditures (including interest capitalized)					
Oil and gas:					
Domestic Onshore					
Exploration	$ 117,100	$ 29,000	$ 26,200	$ 14,500	$ 38,300
Development	143,300	159,500	118,000	117,200	113,600
Purchase of reserves	46,000	583,800	177,700		1,027,200
Domestic Offshore					
Exploration	63,800	54,300	28,100	33,600	18,000
Development	20,900	74,000	23,900	100,700	169,000
Purchase of reserves		24,700			87,700
Canada					
Exploration	9,100				
Development	55,800				
Purchase of reserves	1,786,900				
Purchase of unproved properties	830,000				
Other international					
Exploration		5,600	100		2,000
Development	100				1,200
Total oil and gas	3,073,000	930,900	374,000	266,000	1,457,000
Other	6,000	6,200	2,500	3,300	4,800
Total	$ 3,079,000	$ 937,100	$ 376,500	$ 269,300	$ 1,461,800

(a) Includes approximately $408 million of after-tax gain on the sale of the Company s operation in Hungary and Thailand.

(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.

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. 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. For further discussion of risks and uncertainties that may affect the Company s results, see Risk Factors and the discussion below.

The following discussion of the Company s financial condition and results of operations reflects the recasting as discontinued operations of the Company s Thailand and Hungary operations. See Executive

Overview Closed Sale of Thailand . Except where noted, the following discussion relates to the Company s continuing activities only.

Executive Overview

The Company s objective is to explore for, develop, acquire and produce oil and gas in select locations. In pursuit of that objective, the Company s goal for each year is to add more oil and gas reserves than it produces. The year 2005 marked the fourteenth 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 onshore Canada and also conducts exploration activities in offshore New Zealand. The Company also seeks to maintain a balanced mixture of the gas/oil ratio of its proven reserves base. Over the last several years, the Company has transitioned from a predominately offshore focused company to a company with the majority of its reserves located in the onshore regions of North America. As of December 31, 2005, approximately 86% of the Company s reserves are located onshore. As a result of this transition, the Company has lengthened its reserves to production index to over 9.3 years.

At the end of 2005, proven reserves reached 2,042 Bcfe and production for the year averaged more than 71,500 BOE per day (429,000 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 2005, oil and gas pricing for the Company was strong, with the average price increasing 30% over 2004 on an equivalent barrel basis.

Oil and gas capital and exploration cash expenditures for 2005 were approximately $2.2 billion. Exploration and development operations were allocated approximately $437 million, and approximately $1.8 billion was spent on selective acquisitions in the Company s core areas of operations. For 2005, in the Company s continuing operations, 279 wells were drilled with 255 successfully completed, a 91% success rate. During 2005, approximately 762 Bcfe of proven reserves were added to the Company s reserves ledger.

Closed acquisition of Northrock Resources

On September 27, 2005, the Company completed the acquisition of Northrock Resources Ltd. for approximately $1.7 billion in cash. The purchase price of Northrock was funded using available cash on hand, the net proceeds from the Company s offering of $500 million aggregate principal amount of senior subordinated notes in September 2005 and additional borrowings under the credit facility.

As of December 31, 2005, Northrock owned 657 Bcfe of estimated proven reserves on approximately 300,000 net acres, plus approximately 950,000 net acres of undeveloped leasehold. Northrock s exploitation and development activities are concentrated in Saskatchewan and Alberta with key exploration plays in Canada s Northwest Territories, British Columbia and the Alberta Foothills. The Company expects to have an active drilling program in Canada in 2006, allocating approximately $200 million of capital to drill 184 wells. By allocating significant resources and capital, the Company anticipates growth in both reserves and production from this important new area.

Closed Sale of Thailand

On August 17, 2005, the Company closed the sale of its wholly owned subsidiary Thaipo Ltd. and its 46.34% interest in B8/32 Partners Ltd., effectively a sale of all of its Thailand operations, for a purchase price of $820 million. The company recognized an after-tax gain from discontinued operations of approximately $403 million on the transaction.

Hurricanes Katrina and Rita

On August 29, 2005, after passing through the Gulf of Mexico, Hurricane Katrina made landfall near New Orleans, Louisiana and caused one of the worst natural disasters in U.S. history. On September 24, 2005, Hurricane Rita, one of the strongest measured hurricanes to have entered the Gulf of Mexico, made landfall between Sabine Pass, Texas and Johnson s Bayou, Louisiana. Due to the hurricanes, substantially all of the Company s Gulf of Mexico production was shut-in and, as of February 1, 2006, approximately 4,000 Bbls of oil and 20 MMcf of natural gas of the Company s net daily production remain shut-in as a result of the storms. One of the platforms the Company operates, located in Main Pass Block 123, sustained major damage and significant damage to platforms and pipelines operated by others occurred, including facilities that are located in Viosca Knoll Block 823, Eugene Island Block 330, and South Marsh Island Block 128. The Company expects production to come back on-line by the end of the first quarter of 2007. Also, damage to processing plants and other onshore infrastructure owned and operated by others will likely continue to delay some of the shut-in production from coming back on-line. The Company maintains business interruption insurance on some of its blocks in the Gulf.

Senior Subordinated Notes Issuances

In March 2005, the Company issued and sold $300 million aggregate principal amount of 6.625% Senior Subordinated Notes due 2015. Proceeds from the offering were used to reduce outstanding senior indebtedness under the Company s revolving credit facility.

In September 2005, the Company issued and sold $500 million aggregate principal amount of 6.875% Senior Subordinated Notes due 2017. Proceeds from the offering were used to fund a portion of the purchase price of the Northrock acquisition.

Share Repurchases

During 2005, the Company announced a share repurchase plan. The Company is authorized to expend up to a maximum of $375 million dollars to effect the repurchases. As of February 23, 2006, 7.3 million shares of company stock have been repurchased for $360 million, which represents approximately 11% of the Company s outstanding shares as of January 1, 2005.

2005 Results

Total revenue for 2005 was $1,225.6 million and net income from continuing operations totaled $290.1 million, or $4.80 per share. Cash flow from continuing operations totaled $700.8 million. As of December 31, 2005, long-term debt was $1,646 million, increasing from December 31, 2004 by $891 million. The Company s debt to total capitalization ratio, an indicator of a company s financial strength, was 44% at December 31, 2005 and cash and cash equivalents decreased from $221 million at December 31, 2004 to approximately $58 million at December 31, 2005. The increase in debt and the decrease in cash are both due primarily to the closing of the Northrock acquisition.

2006 Capital Budget

The Company has established a $725 million exploration and development budget (excluding property acquisitions). The Company expects to spend approximately $222 million on exploration and $503 million on development activities. The capital budget calls for the drilling of approximately 451 wells during 2006, including wells in the United States and Canada.

2006 Production Outlook Update

The Company currently expects its production volumes to average approximately 100,000 Boepd during 2006. In addition, the Company currently expects its production volumes to exit 2006 at approximately 112,500 Boepd. These estimates are subject to change, and actual results could differ materially, depending upon the amount of Gulf of Mexico production that remains shut-in, the timing of any such production coming back on-line, the availability of oilfield services, acquisitions, divestitures and many other factors that are beyond the Company s control. Please read Forward-Looking Statements.

Exposure to Oil and Gas Prices and Availability of Oilfield Services

Oil and natural gas prices have historically been seasonal, cyclical and volatile. Prices depend on many factors that the Company cannot control such as weather and economic, political and regulatory conditions. The average prices the Company is currently receiving for production are higher than historical average prices. A future drop in oil and gas prices could have a serious adverse effect on cash flow and profitability. Sustained periods of low prices could have a serious adverse effect on the Company s operations and financial condition. Additionally, the cost of drilling, completing and operating wells and installing facilities and pipelines is often uncertain and have each increased substantially during 2005. The market for oil field services is currently very competitive and shortages or delays in delivery or availability of equipment or fabrication yards could impact the Company s ability to conduct oil and gas drilling and completion operations.

Results of Operations

Oil and Gas Revenues

The Company s oil and gas revenues for 2005 were $1,216,247,000, an increase of approximately 25% from oil and gas revenues of $973,083,000 for 2004, which were an increase of approximately 14% from oil and gas revenues of $856,074,000 for 2003. The following table reflects an analysis of variances in the Company s oil and gas revenues (expressed in thousands) between years:

	2005 Compared to 2004	**2004 Compared to 2003**
Increase (decrease) in oil and gas revenues resulting from variances in:		
Natural gas		
Price .	$ 168,448	$ 43,010
Production .	14,416	72,285
	182,864	115,295
Crude oil and condensate		
Price .	121,758	139,431
Production .	(70,577)	(148,733)
	51,181	(9,302)
Natural gas liquids (NGL)	9,119	11,016
Increase in oil and gas revenues	$ 243,164	$ 117,009

The increase in the Company s oil and gas revenues in 2005, compared to 2004, 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 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 oil and gas revenues for 2005, compared to 2004 and 2003 was also the result of an increase in the average price that the Company received for its NGL production volumes from $21.59 and $28.09 in 2003 and 2004, respectively, to $34.56 in 2005.

	2005	2004	% Change 2004 to 2005	2003	% Change 2003 to 2004
Comparison of Increases (Decreases) in:					
Natural Gas					
Average prices					
United States(a)	**$ 7.46**	$ 5.73	**30 %**	$ 5.17	**11 %**
Canada	**$ 10.96**	$	**N/A**	$	**N/A**
Company-wide average price	**$ 7.62**	$ 5.73	**33 %**	$ 5.17	**11 %**
Average daily production volumes (MMcf per day):					
United States	**231.6**	244.3	**(5)%**	210.4	**16 %**
Canada(c)	**18.6**		**N/A**		**N/A**
Company-wide average daily production	**250.2**	244.3	**2 %**	210.4	**16 %**
Crude Oil and Condensate					
Average prices					
United States(b)	**$ 50.90**	$ 38.59	**32 %**	$ 29.08	**33 %**
Canada	**$ 44.29**	$	**N/A**	$	**N/A**
Company-wide average price	**$ 49.85**	$ 38.59	**29 %**	$ 29.08	**33 %**
Average daily production volumes (Bbls per day):					
United States	**22,337**	29,530	**(24)%**	40,173	**(26)%**
Canada(c)	**3,397**		**N/A**		**N/A**
Company-wide average daily production	**25,734**	29,530	**(13)%**	40,173	**(26)%**

(a) Average prices for the United States reflect the impact of the Company s price hedging activity. Price hedging activity reduced the average price per Mcf. of the Company s United States natural gas production $0.11 and $0.17 during 2005 and 2003, respectively. The Company had no price hedging activity related to 2004 production.

(b) Average prices for the United States include the impact of the Company s price hedging activity. Price hedging activity reduced the average price per Bbl of the Company s crude oil and condensate production $0.20 and $0.69 during 2005 and 2003, respectively. The Company had no price hedging activity related to 2004 production. For average prices, sales volumes equate to actual production.

(c) Northrock Resources was acquired by the Company on September 27, 2005.

Natural Gas Production. The increase in the Company s natural gas production during 2005, compared to 2004, was primarily related to the addition of production from acquisitions made during late 2005 and late 2004, partially offset by shut-in offshore production caused by Hurricanes Ivan, Katrina and Rita and, to a lesser extent, natural production declines. 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 success of the Company s exploration program

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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.

Crude Oil and Condensate Production. The decrease in the Company s crude oil and condensate production during 2005, compared to 2004, resulted primarily from the shut-in of Gulf of Mexico platforms due to the effects of Hurricanes Ivan, Katrina and Rita (including Main Pass Block 61/62) during 2005 and, to a lesser extent, natural production declines. This decrease was partially offset by the addition of production from the Northrock acquisition made on September 27, 2005. 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 and natural production declines at the Company s Main Pass Blocks 61/62 Field in the Gulf of Mexico.

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 2005, compared with 2004, related to an increase in the average price that the Company received for its NGL production to $34.56 in 2005 from $28.09 in 2004. 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 and, to a lesser extent, a slight increase in NGL production volumes.

Other Revenues

Other revenue is derived from sources other than the current production of hydrocarbons. This revenue includes, among other items, natural gas inventory sales, pipeline imbalance settlements and revenue from salt water disposal activities. The increase in the Company s other revenues in 2005, compared to 2004 and 2003, is related primarily to $5.6 million of natural gas inventory sales from the Company s Canadian operations in 2005. No gas inventory sales were made in either 2004 or 2003.

Costs and Expenses

	2005	2004	% Change 2004 to 2005	2003	% Change 2003 to 2004
	(expressed in thousands, except DD&A rate)				
Comparison of Increases (Decreases) in:					
Lease Operating Expenses	**$ 153,659**	**$ 100,506**	**53 %**	$ 81,731	**23 %**
General and Administrative Expenses	**$ 87,319**	**$ 62,506**	**40 %**	$ 54,068	**16 %**
Exploration Expenses	**$ 26,473**	**$ 21,739**	**22 %**	$ 6,899	**215 %**
Dry Hole and Impairment Expenses	**$ 87,170**	**$ 61,634**	**41 %**	$ 30,673	**101 %**
Depreciation, Depletion and Amortization (DD&A) Expenses	**$ 312,247**	**$ 251,876**	**24 %**	$ 229,881	**10 %**
DD&A rate	**$ 1.99**	**$ 1.54**	**29 %**	$ 1.32	**17 %**
Mcfe produced	**156,782**	**163,528**	**(4)%**	173,780	**(6)%**
Production and Other Taxes	**$ 59,527**	**$ 44,104**	**35 %**	$ 23,735	**86 %**
Transportation and Other	**$ (9,079)**	**$ 8,355**	**(209)%**	$ 23,892	**(65)%**
Interest					
Charges	**$ (68,654)**	**$ (29,333)**	**134 %**	$ (46,360)	**(37)%**
Interest Income	**$ 8,291**	**$ 522**	**1488 %**	$ 673	**(22)%**
Capitalized Interest Expense	**$ 23,480**	**$ 14,216**	**65 %**	$ 16,531	**(14)%**
Commodity Derivative Expense	**$ (13,618)**	**$**	**N/M**	$	**N/A**
Loss on debt extinguishment	**$**	**$ (13,759)**	**(100)%**	$ (5,893)	**133 %**
Income Tax Expense	**$ (167,884)**	**$ (148,866)**	**13 %**	$ (137,371)	**8 %**

Lease Operating Expenses

The increase in lease operating expenses for 2005, compared to 2004, is related primarily to increased expenses incurred related to onshore properties acquired by the Company in the fourth quarter of 2004 and throughout 2005, increased maintenance expenses on several of the Company s significant offshore properties due to damage from Hurricanes Ivan, Katrina and Rita (which were only partially offset by insurance recoveries), and also to higher costs being charged by oilfield service companies in 2005. The Company currently expects lease operating expenses to increase in future periods with the addition of Northrock related expenses for an entire reporting period. The increase in 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.

On a per unit of production basis, the Company s total lease operating expenses were $0.47 per Mcfe for 2003, $0.61 per Mcfe for 2004 and $0.98 per Mcfe for 2005. The increased unit costs in 2005 were primarily related to the increased expense and the decreased production volumes discussed above.

General and Administrative Expenses

The increase in general and administrative expenses for 2005, compared with 2004, is primarily related to increases in the size of the Company s workforce due to acquisitions, increased benefit expenses and normal increases in compensation. The Company currently expects general and administrative expenses to increase in future periods with the addition of Northrock related expenses for an entire reporting period. 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). On a per unit of production basis, the Company s general and administrative expenses were $0.56 per Mcfe in 2005, $0.38per Mcfe in 2004 and $0.31 per Mcfe in 2003.

Exploration Expenses

Exploration expenses consist primarily of exploratory geological and geophysical costs that are expensed as incurred and rental payments required under oil and gas leases to hold non-producing properties (delay rentals). The increase in exploration expenses for 2005, compared to 2004, resulted primarily from increased seismic operations in the Company s New Zealand and Canadian operations, which were partially offset by decreased 3-D seismic acquisition activities in the Gulf of Mexico and decreased seismic operations in the Company s Gulf Coast region. 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 increased seismic operations in the Company s Gulf Coast 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 2005 the Company drilled 9 gross unsuccessful exploratory wells (7.1 net to the Company s interest) for a total cost of approximately $67.1 million; in 2004 the Company drilled 7 unsuccessful exploratory wells (5.6 net to the Company s interest) for a total cost of $40.2 million; and in 2003 the Company drilled 5 unsuccessful exploratory wells (4.0 net to the Company s interest) for a total cost of $20.2 million.

Generally accepted accounting principles require that if the expected future cash flow of the Company s reserves on a proved 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. The evaluation of unproved properties requires management s judgment to estimate the fair value of leasehold and exploratory costs related to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn unproved properties. As a result of its review of proved and unproved properties, the Company recognized impairments to oil and gas properties of approximately $20.1 million during 2005, approximately $21.4 million during 2004 and $10.5 million during 2003.

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 establishes cost centers on the basis of an oil or gas trend or play for its onshore oil and gas activities. The Company generally creates cost centers on a field-by-field basis for oil and gas activities in the Gulf of Mexico.

The increase in the Company s DD&A expense for 2005, compared to 2004, resulted primarily from an increased DD&A rate caused by 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 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 properties acquired by corporate acquisitions).

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 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 onshore properties acquired by acquisition).

Production and Other Taxes

The increase in production and other taxes for 2005, compared to 2004, and for 2004, compared to 2003, is primarily related to increased severance taxes due to higher prices and higher onshore production volumes.

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 generally accepted accounting principles, natural gas purchase costs, recognition of recoveries from business interruption insurance, write-down of tubular inventory values and various other operating expenses. The following table shows the significant items included in Transportation and other and the changes between periods (expressed in thousands):

	For the Year Ended December 31,		
	2005	**2004**	**2003**
Business interruption insurance	$ (40,743)	$ (11,133)	$
Transportation costs	14,568	13,318	12,980
Accretion expense	7,995	4,802	4,972
Gas inventory purchases	4,540		
Write-down of tubular inventory value			1,450
Other	4,561	1,368	4,490
Total	$ (9,079)	$ 8,355	$ 23,892

The business interruption insurance relates to claims from the shut-in of a significant portion of the Company s Gulf of Mexico production during 2005 and the fourth quarter of 2004 as a result of the infrastructure damage caused by Hurricanes Ivan, Katrina and Rita. Accretion expense increased in 2005 compared to 2004 due to increased estimates of future liabilities due to rising service costs and the acquisition of Northrock in the third quarter of 2005. Gas inventory purchases are related solely to the Company s Canadian operations and were therefore not present in 2004 and 2003.

Interest

Interest Charges. The increase in the Company s interest charges for 2005, compared to 2004, resulted primarily from an increase in the average amount of the Company s outstanding debt during 2005. The Company incurred approximately $690 million in additional debt in connection with the Northrock acquisition, which had a significant impact on the Company s 2005 interest expense. 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 incurred $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.

Interest Income. The increase in the Company s interest income for 2005, compared to 2004 and 2003 resulted from an increase in the amount of cash and cash equivalents temporarily invested. The cash and cash equivalents invested during 2005 increased primarily due to the sales proceeds from the sale of the Thailand Entities. These proceeds were subsequently used to fund a portion of the Northrock purchase.

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 increase in capitalized interest for 2005, compared to 2004, resulted from an increase in the average amount of capital expenditures subject to interest capitalization during 2005 (approximately $358,000,000) compared to 2004 (approximately $210,000,000). 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 average amount of capital expenditures subject to interest capitalization during 2004 (approximately $210,000,000) compared to 2003 (approximately $192,000,000).

Commodity Derivative Expense

Commodity derivative expense for 2005 represents losses on derivative contracts that no longer qualify for hedge accounting treatment. Although all of the Company s collars are effective as economic hedges, the forecasted shut-in hydrocarbon production from the Company s Gulf of Mexico properties (resulting primarily from hurricane activity during the third quarter of 2005) caused certain of the gas and crude oil collar contracts to lose their qualification for hedge accounting under SFAS 133. The forecasted hydrocarbon production used to identify those derivative contracts that qualify for hedge accounting is subject to change based on the condition of third party infrastructure including pipelines, onshore facilities and many other factors. If hydrocarbon production is deferred beyond the currently forecast schedule, additional contracts may lose their qualification for hedge accounting and further adjustments may be necessary. No such expense was incurred during either 2004 or 2003, as all of the Company s derivative contracts qualified for hedge accounting at that time.

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.

Income Tax Expense

Changes in the Company s income tax expense are a function of the Company s consolidated effective tax rate, the Company s pre-tax income and the jurisdiction in which the income is earned. The increase in the Company s tax expense for 2005, compared to 2004, and for 2004, compared to 2003, resulted primarily from increased pre-tax income in the later years. The Company s consolidated effective tax rate for 2005, 2004 and 2003 was 36.7%, 37.4%, and 36.9%, respectively. The Company currently expects its effective tax rate to decrease approximately 4 to 6 percentage-points over the next two years, based on current earnings levels. This reduction is expected due to the favorable impact of cross-border financing related to the acquisition of Northrock Resources, reductions in the statutory federal income tax rates in Canada from approximately 26% to 22%, the phase-in of a deduction in Canada for Crown royalties, and the phase-in of the deduction for qualified domestic production activities in the United States.

Discontinued Operations

The Thailand Entities and Pogo Hungary are classified as discontinued operations in the Company s financial statements. The summarized financial results and financial position data of the discontinued operations were as follows (amounts expressed in thousands):

Operating Results Data

	Year Ended December 31,		
	2005	**2004**	**2003**
Revenues	$ 252,840	$ 335,291	$ 303,491
Costs and expenses	(126,496)	(237,097)	(163,388)
Other income	4,962	308	2,520
Income before income taxes	131,306	98,502	142,623
Income taxes	(78,456)	(85,783)	(82,751)
Income before gain from discontinued operations, net of tax	52,850	12,719	59,872
Gain on sale, net of tax of $9,736	407,784		
Income from discontinued operations, net of tax	$ 460,634	$ 12,719	$ 59,872

The increase in income from discontinued operations for 2005, compared to 2004, primarily relates to gains recognized on the sale of the discontinued operations. The decrease in revenues and expenses was primarily caused by the absence of Thailand revenues and expenses after the sale date. The decrease in income from discontinued operations for 2004, compared to 2003, primarily relates to dry hole and impairment costs incurred in Hungary and to increased Special Remunitory Benefit (SRB) costs incurred in the Kingdom of Thailand, which were only partially offset by increased revenues in the Kingdom of Thailand. The Company recognized no tax benefit for its costs in Hungary, resulting in a high effective tax rate for each of the periods presented.

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 2005 was $845,537,000. This compares to cash flow from operating activities of $738,715,000 in 2004 and $744,559,000 in 2003. The resulting changes are attributable to the reasons described under Results of Operations above. Cash flow from operating activities during 2005 was more than adequate to fund $564,614,000 in cash expenditures ($506,798,000 for continuing operations and $57,816,000 for discontinued operations) for capital and exploration projects and property acquisitions, excluding corporate acquisition transactions. The approximately $1.7 billion Northrock transaction was funded using available cash on hand, proceeds from the sale of the Company s Thailand Entities, the net proceeds from the Company s offering of the 2017 Notes and additional borrowings under the revolving credit facility. During 2005, the Company issued $300,000,000 principal amount of 2015 Notes, $500,000,000 principal amount 2017 Notes (see descriptions below) and borrowed cash of $91,000,000 (net of repayments) under its revolving credit facility. During 2005, the Company also paid for the repurchase of $351,813,000 of its common stock and paid $15,212,000 of common stock dividends. As of December 31, 2005, the Company had cash and cash equivalents of $57,749,000 and long-term debt obligations of $1,646,000,000 (excluding debt discount) with no repayment obligations until 2009. The Company may determine to repurchase outstanding debt in the future, including in market transactions, privately negotiated transactions or otherwise, depending on market conditions, liquidity requirements, contractual restrictions and other factors.

Effective December 15, 2005, the Company s lenders redetermined the borrowing base under its revolving credit facility at $1,500,000,000. As of February 23, 2006, the Company had an outstanding balance of $585,000,000 under its facility. As such, the available borrowing capacity under the facility was $415,000,000.

Purchase of Northrock Resources Ltd.

On September 27, 2005, the Company completed the acquisition of Northrock for approximately $1.7 billion in cash. Pogo Canada, ULC, a Canadian company and wholly owned subsidiary of the Company, purchased all of the outstanding shares of Northrock pursuant to a share purchase agreement that was entered into on July 8, 2005. As of December 31, 2005, Northrock owned 657 billion cubic feet of gas equivalent (Bcfe) of estimated proven reserves on approximately 292,000 net acres, plus approximately 950,000 net acres of undeveloped leasehold. Northrock s activities are concentrated in Saskatchewan and Alberta with key exploration plays in Canada s Northwest Territories, British Columbia and the Alberta Foothills. The Company acquired Northrock primarily to strengthen its position in North American exploration and development properties.

2017 Notes

On September 23, 2005, the Company issued $500,000,000 principal amount of 2017 Notes. The proceeds from the sale of the 2017 Notes were used to fund a portion of the Northrock acquisition. The

2017 Notes bear interest at a rate of 6.875%, payable semi-annually in arrears on April 1 and October 1 of each year. The 2017 Notes are general unsecured senior subordinated obligations of the Company, and are subordinated in right of payment to the Company s senior indebtedness, which includes the Company s obligations under the revolving credit facility and LIBOR rate advances. The Company, at its option, may redeem the 2017 Notes in whole or in part, at any time on or after October 1, 2010, at a redemption price of 103.4375% of their principal amount and decreasing percentages thereafter. The Company may also redeem a portion of the 2017 Notes prior to October 1, 2008 and some or all of the Notes prior to October 1, 2010, in each case by paying specified premiums. The indenture governing the 2017 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.

2015 Notes

On March 29, 2005, the Company issued $300,000,000 principal amount of 2015 Notes at 99.101%. The proceeds from the sale of the 2015 Notes were used to pay down obligations under the Company s bank credit facility. The 2015 Notes bear interest at a rate of 6.625%, payable semi-annually in arrears on March 15 and September 15 of each year. The 2015 Notes are general unsecured senior subordinated obligations of the Company, and are subordinated in right of payment to the Company s senior indebtedness, which includes the Company s obligations under the revolving credit facility and LIBOR advances. The Company, at its option, may redeem the 2015 Notes in whole or in part, at any time on or after March 15, 2010, at a redemption price of 103.3125% of their principal amount and decreasing percentages thereafter. The Company may also redeem a portion of the 2015 Notes prior to March 15, 2008 and some or all of the Notes prior to March 15, 2010, in each case by paying specified premiums. The indenture governing the 2015 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.

LIBOR Rate Advances

Under separate Promissory Note Agreements dated May 8, 2004 and September 13, 2004, two of the Company s lenders make available to the Company LIBOR rate advances on an uncommitted basis up to $50,000,000. Advances drawn under these agreements are reflected as long-term debt on the Company s balance sheet because the Company currently has the ability and intent to reborrow such amounts under its Credit Agreement. The Company s 2011 Notes, 2015 Notes and 2017 Notes may restrict all or a portion of the amounts that may be borrowed under the Promissory Note Agreements as senior debt. The Promissory Note Agreements permit either party to terminate the letter agreements at any time upon three-business days notice. As of February 23, 2006 there was $40,000,000 outstanding under these agreements.

Future Capital and Other Expenditure Requirements

The Company s capital and exploration budget for 2006, 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 $725,000,000. The Company has included 451 gross wells in its 2006 capital and exploration budget, including wells to be drilled in the United States, Canada and New Zealand. As of February 23, 2006, the Company anticipates that its available cash and cash investments, cash provided by operating activities and funds available under its revolving credit facility 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 February 23, 2006, the Company had completed the purchase of 7,310,000 shares at a total cost of $359.5 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 7A. Quantitative and Qualitative Disclosure about Market Risk. A summary of the Company s known contractual obligations as of December 31, 2005 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)	$ 2,302.7	$ 70.8	$ 141.5	$ 787.5	$ 1,302.9
Operating Lease Obligations(b)	$ 141.7	$ 16.8	$ 29.9	$ 24.0	$ 71.0
Purchase Obligations(c)	$ 23.4	$ 9.6	$ 2.6	$ 2.1	$ 9.1
Asset Retirement Obligations(d)	$ 614.5	$ 4.7	$ 12.3	$ 5.7	$ 591.8
Other Obligations(e)	$ 14.6	$ 14.6	$ 0.0	$ 0.0	$ 0.0
Total	$ 3,096.9	$ 116.5	$ 186.3	$ 819.3	$ 1,974.8

(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 Company s office lease commitments, gas storage fee 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 drilling rigs that have a term greater than six months or which cannot be terminated at the end of the well that is currently being drilled 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 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 14 to the Consolidated Financial Statements.

(e) This represents the Company s estimate of retention bonus payments to be made to those persons employed by Northrock as of September 27, 2005, if those persons remain employees of Northrock on September 27, 2006.

Commitments under Joint Operating Agreements. As is common in the oil and gas industry, the Company operates in many instances through joint ventures under joint operating agreements. 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, 2005, 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 $8.8 million that are not included in the table presented above. 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. As of February 23, 2006, approximately $2 million in letters of credit had been issued on the Company s behalf relating to its Canadian operations.

Credit Agreement and Borrowing Base Determination

Credit Agreement. The Company has a revolving credit facility (the Credit Agreement) that provides for a $1.0 billion 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. As of February 23, 2006, the borrowing base was $1.5 billion. 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, 2006. 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 February 23, 2006, there was $585 million 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 the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. The Company s significant accounting policies are described in Note 1 to the consolidated financial statements included in this Annual Report on Form 10-K. We have identified below policies that are of particular importance to the portrayal of its financial position and results of operations and which require the application of significant judgment by management. The Company analyzes its 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 bases its estimates on historical experience and various other assumptions that management believes to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. The Company believes the following critical accounting policies affect its 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 included in unproved properties 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 2.75%, 1.05% and 3.66% of proved reserves during the years ended December 31, 2005, 2004 and 2003, 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 at December 31, 2005 of 1% would result in an annual increase in DD&A expense of approximately $3.6 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 2005, 2004 and 2003. 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 initially 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.

Derivative contracts that do not initially qualify for hedge accounting treatment or lose their qualification for hedge accounting treatment (such as those contracts that lost the qualification for hedge accounting treatment during 2005 due to curtailed production resulting from hurricane damage) are carried at their fair value on the Company s consolidated balance sheet. The Company recognizes all changes in the fair value of these contracts in the Company s consolidated results of operations in the period in which the change occurs in the caption Commodity derivative expense.

Business Combinations/Acquisitions

In 2005, the Company grew through the acquisition of Northrock Resources. This acquisition was 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 estimated fair value of both proved and unproved 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 fair value of proved reserves is then used to estimate the fair value of proved property costs acquired in a business combination. 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. The fair value of probable and possible reserves is then used to estimate the fair value of unproved property costs acquired in a business combination. 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, 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 $16 million (representing an increase of approximately 10% to the Company s December 31, 2005 asset retirement obligation) to increase the Company s DD&A rate by $0.01 per Mcfe for the year ended December 31, 2005.

Recognition of Insurance Recoveries

The Company recognizes estimated proceeds from insurance recoveries only when the amount of the recovery is determinable and when the Company believes that the proceeds are probable of recovery. When the amount of the estimated recoveries has been determined and when the Company has concluded that the recovery is probable, the recoveries are recognized in the results of operations. Business interruption proceeds are recorded as a reduction of Transportation and other expense and property damage recoveries are recorded as a reduction of Lease operating expense .

Pension and Other Post-Retirement Benefits

Accounting for pensions and other post-retirement 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 10 to the Consolidated Financial Statements.

Income Taxes

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

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

Other Matters

Inflation. Publicly held companies are asked to comment on the effects of inflation on their business. As of February 23, 2006, 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 considered significant as of February 23, 2006.

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

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

Commodity Price Risk

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

Interest Rate Risk

From time to time, the Company has entered into various financial instruments, such as interest rate swaps, to manage the impact of changes in interest rates. As of February , 2006, 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, 2005:

	2006	2007	2008	2009	2010	Thereafter	Total	Fair Value
Long-Term Debt:								
Variable Rate	$ 0	$ 0	$ 0	$ 646,000	$ 0	$ 0	$ 646,000	$ 646,000
Average Interest Rate				5.82 %			5.82 %	
Fixed Rate	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,000,000	$ 1,000,000	$ 985,250
Average Interest Rate						7.08 %	7.08 %	

Foreign Currency Exchange Rate Risk

In addition to the U.S. dollar, the Company and certain of its subsidiaries conduct a substantial portion of their business in Canadian dollars and are therefore subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing and investing transactions conducted in Canada. As of February 23, 2006, the Company is not a party to any foreign currency exchange agreement.

Current Hedging Activity

As of December 31, 2005, the Company held various derivative instruments. The Company has 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 a significant portion of 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 derivative 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 derivative 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, 2005 are as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price Floor	Ceiling	Fair Value of Liability
Natural Gas Contracts (MMBtu)(a)				
Collar Contracts:				
January 2006 - December 2006	5,475	$ 5.00	$ 7.50	$ (18,527,528)
January 2006 - December 2006	1,825	$ 5.50	$ 8.25	$ (5,106,509)
January 2006 - December 2006	3,650	$ 5.75	$ 8.27	$ (10,053,301)
January 2006 - December 2006	10,950	$ 6.00	$ 13.50	$ (4,942,274)
January 2006 - December 2006	1,825	$ 6.00	$ 13.55	$ (809,200)
January 2006 - December 2006	3,650	$ 6.00	$ 13.60	$ (1,589,865)
January 2006 - December 2006	10,950	$ 6.00	$ 14.00	$ (4,134,399)
January 2007 - December 2007	5,475	$ 6.00	$ 12.00	$ (5,536,823)
January 2007 - December 2007	9,125	$ 6.00	$ 12.15	$ (8,878,679)
January 2007 - December 2007	3,650	$ 6.00	$ 12.20	$ (3,505,893)
January 2007 - December 2007	9,125	$ 6.00	$ 12.50	$ (8,106,668)
Crude Oil Contracts (Barrels)				
Collar Contracts:				
January 2006 - December 2006	1,460,000	$ 50.00	$ 78.00	$ (976,728)
January 2006 - December 2006	365,000	$ 50.00	$ 79.00	$ (195,932)
January 2006 - December 2006	1,460,000	$ 50.00	$ 81.00	$ (439,482)
January 2006 - December 2006	365,000	$ 50.00	$ 81.04	$ (108,279)
January 2006 - December 2006	1,825,000	$ 50.00	$ 82.00	$ (357,749)
January 2007 - December 2007	1,460,000	$ 50.00	$ 75.00	$ (3,463,645)
January 2007 - December 2007	365,000	$ 50.00	$ 75.25	$ (842,944)
January 2007 - December 2007	3,650,000	$ 50.00	$ 77.50	$ (6,439,226)

(a) MMBtu means million British Thermal Units.

Although all of the Company s collars are effective as economic hedges, the forecasted shut-in hydrocarbon production from the Company s Gulf of Mexico properties (resulting primarily from hurricane activity during the third quarter of 2005) caused certain of the gas and crude oil collar contracts to lose their qualification for hedge accounting under SFAS 133. As a result, the Company reclassified $18.7 million of previously deferred losses from accumulated other comprehensive income to Commodity derivative expense in the income statement during the third quarter of 2005. Additionally, the Company now recognizes all future changes in the fair value of these collar contracts in the consolidated statement of income for the period in which the change occurs under the caption Commodity derivative expense. As of December 31, 2005, the Company had the following collar contracts that no longer qualify for hedge accounting:

Contract Period and Type of Contract	Volume	NYMEX Contract Price Floor	Ceiling	Fair Value of Liability
Natural Gas Contracts (MMBtu)				
Collar Contracts:				
January 2006 - November 2006	1,825	$ 5.50	$ 8.25	$ (5,034,443)

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 integrated audits of Pogo Producing Company s 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 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, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 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 14 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, 2005 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, 2005, 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.

As described in Management s Report on Internal Control Over Financial Reporting, management has excluded the Company s Canadian division from it assessment of internal control over financial reporting as of December 31, 2005 because the division was formed with the acquisition of Northrock Resources Ltd. in a purchase business combination during 2005. We have also excluded the Canadian division from our audit of internal control over financial reporting. The Canadian division is a wholly-owned subsidiary of the Company whose total assets and total revenues represent 49% and 11%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2005.

PRICEWATERHOUSECOOPERS LLP

Houston, Texas
March 2, 2006

POGO PRODUCING COMPANY & SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2005	2004	2003
	(Expressed in thousands, except per share amounts)		
Revenues:			
Oil and gas	$ 1,216,247	$ 973,083	$ 856,074
Other	9,452	3,472	2,431
Total	1,225,699	976,555	858,505
Operating Costs and Expenses:			
Lease operating	153,659	100,506	81,731
General and administrative	87,319	62,056	54,068
Exploration	26,473	21,739	6,899
Dry hole and impairment	87,170	61,634	30,673
Depreciation, depletion and amortization	312,247	251,876	229,881
Production and other taxes	59,527	44,104	23,735
Transportation and other	(9,079)	8,355	23,892
Total	717,316	550,270	450,879
Operating Income	508,383	426,285	407,626
Interest:			
Charges	(68,654)	(29,333)	(46,360)
Income	8,291	522	673
Capitalized	23,480	14,216	16,531
Commodity Derivative Expense	(13,618)		
Loss on debt extinguishment		(13,759)	(5,893)
Foreign Currency Transaction Gain (Loss)	71	(30)	29
Income From Continuing Operations Before Taxes and Cumulative Effect of Change in Accounting Principle	457,953	397,901	372,606
Income Tax Expense	(167,884)	(148,866)	(137,371)
Income From Continuing Operations Before Cumulative Effect of Change in Accounting Principle	290,069	249,035	235,235
Income from Discontinued Operations, net of tax	460,634	12,719	59,872
Cumulative Effect of Change in Accounting Principle			(4,166)
Net Income	$ 750,703	$ 261,754	$ 290,941
Earnings (Loss) per Common Share:			
Basic			
Income from continuing operations before cumulative effect of change in accounting principle	$ 4.80	$ 3.90	$ 3.76
Income from discontinued operations	7.63	0.20	0.96
Cumulative effect of change in accounting principle			(0.07)
Net income	$ 12.43	$ 4.10	$ 4.65
Diluted			
Income from continuing operations before cumulative effect of change in accounting principle	$ 4.76	$ 3.87	$ 3.67
Income from discontinued operations	7.56	0.19	0.93
Cumulative effect of change in accounting principle			(0.06)
Net income	$ 12.32	$ 4.06	$ 4.54
Dividends per Common Share	$ 0.25	$ 0.2125	$ 0.20

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

POGO PRODUCING COMPANY & SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2005	2004
	(Expressed in thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 57,749	$ 86,456
Accounts receivable	198,792	120,466
Other receivables	19,957	20,875
Federal income taxes receivable	21,661	10,708
Deferred income tax	12,165	
Inventories product	13,220	
Inventories tubulars	19,057	9,112
Price hedge contracts		6,722
Other	4,220	3,987
Assets of discontinued operations		187,084
Total current assets	346,821	445,410
Property and Equipment:		
Oil and gas, on the basis of successful efforts accounting		
Proved properties	6,254,516	4,003,332
Unproved properties	872,164	76,890
Other, at cost	40,531	28,656
	7,167,211	4,108,878
Accumulated depreciation, depletion, and amortization		
Oil and gas	(1,858,275)	(1,551,502)
Other	(24,551)	(19,194)
	(1,882,826)	(1,570,696)
Property and equipment, net	5,284,385	2,538,182
Other Assets:		
Other	44,542	17,420
Assets of discontinued operations		480,097
	44,542	497,517
	$ 5,675,748	$ 3,481,109

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

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POGO PRODUCING COMPANY & SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (Continued)

	December 31, 2005	2004
	(Expressed in thousands)	
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities:		
Accounts payable operating activities	$ 167,323	$ 62,156
Accounts payable investing activities	137,137	86,582
Income taxes payable	2,034	131
Accrued interest payable	20,225	4,550
Accrued payroll and related benefits	3,717	3,566
Price hedge contracts	52,245	
Deferred income tax		4,919
Other	12,480	8,187
Liabilities of discontinued operations		109,928
Total current liabilities	395,161	280,019
Long-Term Debt	1,643,452	755,000
Deferred Income Tax	1,316,895	536,823
Asset Retirement Obligation	149,374	74,046
Other Liabilities and Deferred Credits	72,284	21,367
Liabilities of Discontinued Operations		85,959
Total liabilities	3,577,166	1,753,214
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 65,275,106 and 64,580,639 shares issued, respectively	65,275	64,581
Additional capital	977,885	943,690
Retained earnings	1,464,214	728,723
Accumulated other comprehensive income (loss)	(30,019)	2,565
Deferred compensation	(17,522)	(9,954)
Treasury stock (7,365,359 and 55,359 shares, respectively), at cost	(361,251)	(1,710)
Total shareholders equity	2,098,582	1,727,895
	$ 5,675,748	$ 3,481,109

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

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POGO PRODUCING COMPANY & SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2005	2004	2003
	(Expressed in thousands)		
Cash flows from operating activities:			
Cash received from customers	$ 1,238,472	$ 978,541	$ 876,016
Operating, exploration and general and administrative expenses paid	(332,041)	(243,276)	(178,653)
Income taxes paid	(197,833)	(159,559)	(121,923)
Income taxes received	166	381	
Interest paid	(51,322)	(30,043)	(45,527)
Cash paid related to price hedge contracts	(11,354)		(15,037)
Business interruption insurance proceeds	47,077		
Other	7,636	(1,752)	7,773
Net cash provided by continuing operating activities	700,801	544,292	522,649
Net cash provided by discontinued operating activities	144,736	194,423	221,910
Net cash provided by operating activities	845,537	738,715	744,559
Cash flows from investing activities:			
Capital expenditures	(374,960)	(285,885)	(191,379)
Purchase of properties	(131,838)	(189,597)	(189,083)
Acquisition of corporations, net of $32,870 and $11,970 cash acquired, respectively	(1,704,590)	(270,452)	
Proceeds from the sale of corporations, net of $51,529 cash on hand	763,618		
Purchase of current investments	(16,750)	(15,000)	
Sale of current investments	122,250	15,000	
Other	9,831	1,522	521
Net cash used in continuing investing activities	(1,332,439)	(744,412)	(379,941)
Net cash used in discontinued investing activities	(57,816)	(217,314)	(186,516)
Net cash used in investing activities	(1,390,255)	(961,726)	(566,457)
Cash flows from financing activities:			
Borrowings under senior debt agreements	3,865,000	2,010,000	854,012
Payments under senior debt agreements	(3,774,000)	(1,594,000)	(875,000)
Proceeds from issuance of new financing	797,303		
Purchase of Company stock	(351,813)		
Payments (to) from discontinued operations	138,287	(24,955)	32,464
Redemption of debt		(157,782)	(176,578)
Proceeds from exercise of stock options	11,169	12,013	33,370
Payment of cash dividends on common stock	(15,212)	(13,607)	(12,520)
Payment of senior debt acquired through corporate purchase		(50,000)	
Payment of financing issue costs and other	(14,806)	(3,820)	(100)
Net cash (used in) provided by continuing financing activities	655,928	177,849	(144,352)
Net cash (used in) provided by discontinued financing activities	(139,630)	24,955	(32,464)
Net cash (used in) provided by financing activities	516,298	202,804	(176,816)
Effect of exchange rate changes on cash from discontinued operations	(287)	2,189	739
Net increase in cash and cash equivalents	(28,707)	(18,018)	2,025
Cash and cash equivalents from continuing operations, beginning of the year	33,488	55,759	57,403
Cash and cash equivalents from discontinued operations, beginning of the year	52,968	48,715	45,046
Cash and cash equivalents at the end of the year	$ 57,749	$ 86,456	$ 104,474

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

POGO PRODUCING COMPANY & SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

	Year Ended December 31, 2005	2004	2003
	(Expressed in thousands)		
Reconciliation of net income to net cash provided by operating activities:			
Net income	$ 750,703	$ 261,754	$ 290,941
Adjustments to reconcile net income to net cash provided by operating activities			
Income from discontinued operations, net of tax	(460,634)	(12,719)	(59,872)
Cumulative effect of change in accounting principle			4,166
(Gains) losses on sales	(72)	275	(386)
Depreciation, depletion and amortization	312,247	251,876	229,881
Dry hole and impairment	87,170	61,634	30,673
Interest capitalized	(23,480)	(14,216)	(16,531)
Price hedge contracts	1,314	(657)	8,346
Other	15,433	23,375	14,732
Deferred income taxes	9,110	3,070	26,800
Change in assets and liabilities:			
Increase in accounts receivable	(9,949)	(26,716)	(16,091)
Increase in federal income taxes receivable	(43,199)	(12,735)	(4,743)
Increase in inventory product	(12,101)		
Decrease in other assets	2,314	3,505	4,568
Increase in accounts payable	54,337	12,683	13,467
Increase (decrease) in income taxes payable	1,900	(652)	(6,607)
Increase (decrease) in accrued interest payable	15,675	(5,400)	(1,146)
Increase in accrued payroll and related benefits	151	333	226
Increase (decrease) in other current liabilities	(2,661)	(3,713)	982
Increase in deferred credits	2,543	2,595	3,243
Net cash provided by continuing operating activities	700,801	544,292	522,649
Net cash provided by discontinued operating activities	144,736	194,423	221,910
Net cash provided by operating activities	$ 845,537	$ 738,715	$ 744,559

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	Accumulated Other Compre-hensive Income (Loss)	Deferred Compen-sation Restricted Stock	Treasury Stock	Share-holders Equity	Compre-hensive Income (Loss)
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	
Reclassification adjustment included in net income								
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	
Net income			750,703				750,703	$ 750,703
Stock option activity and other	363	15,928					16,291	
Shares issued as compensation	331	18,267					18,598	
Issuance of restricted stock, less amortization of $4,585					(7,568)		(7,568)	
Dividends ($0.25 per common share)			(15,212)				(15,212)	
Share repurchase						(359,541)	(359,541)	
Unrealized loss arising during the year on price hedge contracts				(72,189)			(72,189)	
Reclassification adjustment included in net income				16,672			16,672	
Net unrealized gains on price hedge contracts								(55,517)

Foreign currency translation adjustment				22,933			22,933	22,933
Comprehensive income								$ 718,119
Balance at December 31, 2005	65,275	$ 977,885	$ 1,464,214	$ (30,019)	$ (17,522)	$ (361,251)	$ 2,098,582	

(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 North America, both onshore principally in Canada and the states of New Mexico, Texas, Louisiana, Wyoming and Indiana, and offshore in the Gulf of Mexico (primarily in federal waters offshore Louisiana and Texas). The Company also conducts exploration activities in offshore New Zealand.

The Company s results for all periods presented reflect its oil and gas exploration, development and production activities in the Kingdom of Thailand and Hungary as discontinued operations. Except where noted, the discussions in the following notes relate to the Company s continuing activities only.

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, the impairment of oil and gas properties, and the Company s allocation of purchase price to acquired properties are all 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, after elimination of all significant intercompany transactions. Majority owned subsidiaries are fully consolidated. The Company s operating and working interests in oil and gas joint ventures are pro rata consolidated.

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. The Company s crude oil and natural gas 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

The Company maintains natural gas and crude oil and condensate inventories in storage facilities and pipelines in Canada. These inventories are stated at the lower of average cost or market value. The product inventory at December 31, 2005 consisted of approximately 1,892,276 Mcf of natural gas valued at its estimated average cost of $8.25 per Mcf and 77,462 barrels of crude oil and condensate at its estimated average cost of $22.63 per barrel. Natural gas inventory used as storage facility cushion gas to maintain operation pressures is carried as a long-term asset.

Inventories Tubulars

Tubular inventories consist primarily of tubular pipe and general equipment 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. Estimated fair value includes the estimated present value of all reasonably expected future production, prices, and costs. 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 evaluation of unproved properties requires management s judgment to estimate the fair value of leasehold and exploratory costs related to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn unproved properties. 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 2005, 2004 and 2003 (amounts expressed in thousands):

	2005	2004	2003
Balance at January 1,	$ 11,806	$ 976	$ 11,080
Additions to capitalized exploratory well costs pending the determination of proved reserves	7,098	10,830	39
Reclassifications to proved oil and gas properties	(6,748)		(10,143)
Capitalized exploratory well costs charged to expense	(5,057)		
Balance at December 31,	$ 7,099	$ 11,806	$ 976

As of December 31, 2005, the Company has no exploratory well costs that have been capitalized for a period greater than one year since the completion of drilling.

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. 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 Company generally creates cost centers on a field-by-field basis for oil and gas activities in the Gulf of Mexico. 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) losses on sales 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, the historical volatility of oil and gas commodity prices and the recent production disruptions resulting from hurricanes, 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.

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. To the extent the forecasted transaction in a designated and qualifying hedge relationship is no longer probable of occurring, gains and losses previously deferred in other comprehensive income are immediately reclassified to earnings under the caption Commodity derivative expense. For those derivative instruments that do not qualify as a cash flow hedge instrument, the Company recognizes all future changes in the fair value of these instruments in the consolidated statement of income for the period in which the change occurs under the caption Commodity derivative expense.

Insurance Recoveries

The Company recognizes estimated proceeds from insurance recoveries only when the amount of the recovery is determinable and when the Company believes that the proceeds are probable of recovery. When the amount of the estimated recoveries has been determined and when the Company has concluded that the recovery is probable, the recoveries are recognized in the results of operations. Business interruption proceeds are recorded as a reduction of Transportation and other expense and property damage recoveries are recorded as a reduction of Lease operating expense . During the years ended December 31, 2005 and 2004 the Company recognized $40,743,000 and $11,133,000, respectively of business interruption insurance recoveries related to deferred production resulting from Hurricanes Ivan, Katrina and Rita.

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 December 31, 2005, the Company had completed the purchase of 7,310,000 shares at a total cost of $359.5 million.

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. 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, Stock Awards). 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. On January 1, 2006, the Company will adopt the provisions of SFAS No. 123 (revised 2004) (SFAS 123R), Share-Based Payment , which replaces the provisions of SFAS 123. The adoption of SFAS 123R is not expected to have a material effect on the Company s financial statements.

Compensation cost for restricted stock, 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 351,800 shares of common stock with a fair market value of $19,528,000

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

during the year ended December 31, 2005. 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 following table illustrates the effect on the Company s net income and earnings per share (including the results of discontinued operations) 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, 2005, 2004 and 2003 (in thousands of dollars, except per share amounts):

	Year Ended December 31, 2005	2004	2003
Net income, as reported	$ 750,703	$ 261,754	$ 290,941
Add: Employee stock-based compensation expense, net of related tax effects, included in net income, as reported	5,389	3,006	1,408
Deduct: Total employee stock-based compensation expense, determined under fair value method for all awards, net of related tax effects	(6,802)	(6,759)	(7,017)
Net income, pro forma	$ 749,290	$ 258,001	$ 285,332
Earnings per share:			
Basic as reported	$ 12.43	$ 4.10	$ 4.65
Basic pro forma	$ 12.41	$ 4.04	$ 4.56
Diluted as reported	$ 12.32	$ 4.06	$ 4.54
Diluted pro forma	$ 12.30	$ 4.01	$ 4.45

The fair value of restricted stock grants was estimated based on the average of the high and low share price on the date of grant. The fair value of stock option grants was estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used in 2004 and 2003, respectively: risk free interest rates of 3.00% and 2.30%, expected volatility of 25.7% and 28.4%, dividend yields of 0.48% and 0.61%, and an expected life of the options of three and a half and three years. No stock options were granted in 2005.

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. Significant non-cash transactions are disclosed in the Consolidated Statements of Shareholders Equity relating to shares issued as compensation and in Note 14 relating to asset retirement costs.

Foreign Currency

The Canadian dollar is the functional currency for the Company s Canadian operations. Accordingly, foreign exchange translation adjustments resulting from translating the Northrock financial statements from Canadian dollars to U.S. dollars are included as a separate component of other comprehensive income in shareholders equity on the consolidated balance sheet. Gains or losses incurred on currency transactions in other than Canadian dollars are included in the consolidated statements of income for the period in which the transactions occur.

The U.S. dollar is the functional currency for all areas of operations of the Company other than Canada. 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

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

(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 indicated. 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.

	2005	2004	2003
Income (numerator):			
Income from continuing operations	$ 290,069	$ 249,035	$ 235,235
Income from discontinued operations, net of tax	460,634	12,719	59,872
Income before cumulative effect of change in accounting principle	750,703	261,754	295,107
Cumulative effect of change in accounting principle			(4,166)
Net income basic	750,703	261,754	290,941
Interest expense incurred, net of taxes, and shares issued related to the assumed conversion at $42.185 per share of the 2006 Notes			2,106
Net income diluted	$ 750,703	$ 261,754	$ 293,047
Weighted average shares (denominator):			
Weighted average shares basic	60,372	63,848	62,538
Shares assumed issued from the exercise of options to purchase common shares and restriced stock, net of treasury shares assumed purchased from the proceeds, at the average market price for the period	552	545	683
Dilution effect of 2006 Notes			1,391
Weighted average shares diluted	60,924	64,393	64,612
Earnings per share:			
Basic:			
Income from continuing operations	$ 4.80	$ 3.90	$ 3.76
Income from discontinued operations	7.63	0.20	0.96
Cumulative effect of change in accounting principle			(0.07)
Basic earnings per share	$ 12.43	$ 4.10	$ 4.65
Diluted:			
Income from continuing operations	$ 4.76	$ 3.87	$ 3.67
Income from discontinued operations	7.56	0.19	0.93
Cumulative effect of change in accounting principle			(0.06)
Diluted earnings per share	$ 12.32	$ 4.06	$ 4.54
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	467
Average price	$	$ 49.02	$ 41.87

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POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(3) Income Taxes

The components of income from continuing operations before income taxes and cumulative effect of change in accounting principle for each of the three years in the period ended December 31, 2005, are as follows (expressed in thousands):

	2005	2004	2003
United States	$ 417,655	$ 403,845	$ 373,267
Foreign	40,298	(5,944)	(661)
Income from continuing operations before income taxes and cumulative effect of change in accounting principle	$ 457,953	$ 397,901	$ 372,606

The components of income tax expense (benefit) for each of the three years in the period ended December 31, 2005, are as follows (expressed in thousands):

	2005	2004	2003
Current			
United States	$ 156,882	$ 145,730	$ 110,572
Foreign	1,908	60	397
Deferred			
United States	(6,141)	3,076	26,402
Foreign	15,235		
Income tax expense	$ 167,884	$ 148,866	$ 137,371

Total income tax expense for each of the three years in the period ended December 31, 2005, 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):

	2005	2004	2003
Federal statutory income tax rate	35.0 %	35.0 %	35.0 %
Increases resulting from:			
State income taxes, net of federal benefits	1.6	1.5	1.0
Other	0.1	0.9	0.9
	36.7 %	37.4 %	36.9 %

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The principal components of the Company s deferred income tax assets and liabilities at December 31, 2005 and 2004 (expressed in thousands) are as follows:

	December 31, 2005	2004
Deferred tax assets:		
Foreign deferred tax assets and net operating loss carry forwards	$ 6,347	$ 3,049
Valuation allowance of deferred tax assets and foreign net operating loss	(6,347)	(3,049)
Tax basis in excess of book basis for price hedge contracts	35,203	
Tax basis in excess of book basis for deferred compensation and benefit plans	20,004	12,691
Net operating loss carryforwards	2,386	
Other	4,278	3,561
	61,871	16,252
Deferred tax liabilities:		
Book basis in excess of tax basis for oil and gas properties and equipment	(1,360,860)	(548,799)
Other	(5,741)	(9,195)
	(1,366,601)	(557,994)
Net deferred tax liability	$ (1,304,730)	$ (541,742)

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 acquired corporations during 2004 and 2005.

As of December 31, 2005, the Company had foreign net operating loss (NOL) carryforwards of approximately $20 million that may be used in future years to offset foreign taxable income. The majority of these NOL carryforwards have no expiration date, however their utilization may be subject to limitations due to enacted tax legislation within the applicable foreign jurisdiction and their realization is dependent upon generating sufficient taxable income within the applicable foreign jurisdiction. The $6.3 million valuation allowance at December 31, 2005 was related to exploration expenses the Company incurred in its foreign operations. During 2005, the Company recorded an additional valuation allowance of $3.3 million, primarily related to exploration expenses in New Zealand.

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 $29,117,000 at December 31, 2005. 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 provides a deduction for income from qualified domestic production activities, which will be phased in from 2005 through 2010. The Act also created a temporary incentive for U.S. corporations to repatriate accumulated income earned abroad by providing an 85 percent dividends received deduction for certain dividends from controlled foreign corporations. The Company adopted a Domestic Reinvestment Plan

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

that qualifies for the temporary incentive. Based on that decision, the Company repatriated $497 million in extraordinary dividends, as defined in the Act, during the third quarter of 2005. The Company also repatriated an additional $315 million that did not qualify for the temporary incentive. As a result of the repatriation of $812 million, the Company recorded a U.S. tax expense of $24.1 million during 2005.

(4) Long-Term Debt

Long-term debt at December 31, 2005 and 2004, consists of the following (dollars expressed in thousands):

	December 31, 2005	2004
Senior debt		
Bank revolving credit facility:		
LIBOR based loans, borrowings at December 31, 2005 and 2004 at interest rates of 5.837% and 3.665%, respectively	$ 606,000	$ 515,000
LIBOR Rate Advances, borrowings at December 31, 2005 and 2004 at interest rates of 5.618% and 3.5275%, respectively	40,000	40,000
Total senior debt	646,000	555,000
Subordinated debt		
8.25% Senior subordinated notes, due 2011	200,000	200,000
6.625% Senior subordinated notes, due 2015	300,000	
6.875% Senior subordinated notes, due 2017	500,000	
Total subordinated debt	1,000,000	200,000
Unamortized discount on 2015 Notes	(2,548)	
Long-term debt	$ 1,643,452	$ 755,000

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 $1,000,000,000 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, 2005, the borrowing base was $1,500,000,000. 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,

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 Facility) 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.

On September 23, 2005, the Company issued $500,000,000 principal amount of 2017 Notes. The proceeds from the sale of the 2017 Notes were used to fund a portion of the Northrock acquisition. The 2017 Notes bear interest at a rate of 6.875%, payable semi-annually in arrears on April 1 and October 1 of each year. The 2017 Notes are general unsecured senior subordinated obligations of the Company, and are subordinated in right of payment to the Company s senior indebtedness, which includes the Company s obligations under the bank revolving credit agreement and LIBOR rate advances. The Company, at its option, may redeem the 2017 Notes in whole or in part, at any time on or after October 1, 2010, at a redemption price of 103.4375% of their principal amount and decreasing percentages thereafter. The Company may also redeem a portion of the 2017 Notes prior to October 1, 2008 and some or all of the Notes prior to October 1, 2010, in each case by paying specified premiums. The indenture governing the 2017 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.

On March 29, 2005, the Company issued $300,000,000 principal amount of 2015 Notes at 99.101%. The proceeds from the sale of the 2015 Notes were used to pay down obligations under the Company s bank credit facility. The 2015 Notes bear interest at a rate of 6.625%, payable semi-annually in arrears on March 15 and September 15 of each year. The 2015 Notes are general unsecured senior subordinated

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

obligations of the Company, and are subordinated in right of payment to the Company s senior indebtedness, which includes the Company s obligations under the bank revolving credit agreement and LIBOR rate advances. The Company, at its option, may redeem the 2015 Notes in whole or in part, at any time on or after March 15, 2010, at a redemption price of 103.3125% of their principal amount and decreasing percentages thereafter. The Company may also redeem a portion of the 2015 Notes prior to March 15, 2008 and some or all of the Notes prior to March 15, 2010, in each case by paying specified premiums. The indenture governing the 2015 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 asset sales; non-guarantor restricted subsidiaries; dividends and other payment restrictions affecting restricted subsidiaries; and merger, consolidations and the sale of assets.

On April 10, 2001, the Company issued $200,000,000 principal amount of 2011 Notes. The 2011 Notes bear interest at a rate of 8.25%, 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 amount 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 asset sales; non-guarantor restricted subsidiaries; dividends and other payment restrictions affecting restricted subsidiaries; and merger, consolidations and the sale of assets.

The Company gave notice on March 18, 2004 of its intent to redeem all $150,000,000 of its 10.375% 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.

(5) Commitments and Contingencies

The Company has commitments for operating leases (primarily for office space) in Houston, Calgary, Midland, Laredo, and for other equipment (including gas compressors). Rental expense for office space was $3,305,000 in 2005, $2,859,000 in 2004, and $2,739,000 in 2003. Rental expense for other equipment was $6,782,000 in 2005, $5,497,000 in 2004 and $4,241,000 in 2003.

Future minimum lease payments related to the Company s operating leases at December 31, 2005 are approximately $16,729,000 in 2006; $16,302,000 in 2007; $13,630,000 in 2008; $12,997,000 in 2009; $11,047,000 in 2010 and $70,952,000 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.

The Company has in place a retention incentive plan that covers only those employees who were employed by Northrock on September 27, 2005 (the date of acquisition). If the covered employees are still employed by Northrock on September 27, 2006, they will receive an incentive plan payment. The Company estimates that the total liability related to the retention incentive plan will be approximately $14.6 million.

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(6) 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 the customer who has exceeded 10% of revenues in any given year (expressed in thousands):

	2005	2004	2003
Shell Trading Company	$ 117,456	$ 147,076	$ 161,451

(7) Credit Risk

Substantially all of the Company s accounts receivable at December 31, 2005 and 2004, 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 The Company provides reserves for specifically identified receivables from customers and joint interest owners that, in the opinion of management, are considered doubtful. As of December 31, 2005 and 2004, the Company s allowances for doubtful accounts were not material.

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(8) 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:

	2005	2004	2003
	(Expressed in thousands)		
Long-Lived Assets:			
As of December 31,			
United States	$ 2,624,663	$ 2,538,182	$ 1,904,676
Canada	2,659,722		
Other			67
Total	$ 5,284,385	$ 2,538,182	$ 1,904,743
Capital Expenditures:			
(including interest capitalized)			
For the year ended December 31,			
United States	$ 397,192	$ 931,444	$ 376,430
Canada	2,681,855		
Other		5,656	70
Total	$ 3,079,047	$ 937,100	$ 376,500
Revenues:			
For the year ended December 31,			
United States	$ 1,085,712	$ 976,555	$ 858,505
Canada	139,636		
Other	351		
Total	$ 1,225,699	$ 976,555	$ 858,505
Depreciation, depletion, and amortization expense:			
For the year ended December 31,			
United States	$ 261,324	$ 251,876	$ 229,881
Canada	50,923		
Other			
Total	$ 312,247	$ 251,876	$ 229,881
Operating income (loss):			
For the year ended December 31,			
United States	$ 474,138	$ 432,741	$ 408,830
Canada	43,876		
Other	(9,631)	(6,456)	(1,204)
Total	$ 508,383	$ 426,285	$ 407,626

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(9) Discontinued Operations

Under SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, the Company classifies assets to be disposed of as held for sale or, if appropriate, discontinued operations when they have received appropriate approvals by the Company s management or Board of Directors and when they meet other criteria. As of December 31, 2005, the Company had completed the sale of the assets discussed below.

Thaipo Ltd. and B8/32 Partners Ltd.

On August 17, 2005, the Company completed the sale of its wholly owned subsidiary Thaipo Ltd. and its 46.34% interest in B8/32 Partners Ltd. (collectively referred to as the Thailand Entities) for a purchase price of $820 million. The Company recognized an after tax gain of approximately $403 million on the sale of the Thailand Entities.

Pogo Hungary Ltd.

On June 7, 2005, the Company completed the sale of its wholly owned subsidiary Pogo Hungary, Ltd. (Pogo Hungary) for a purchase price of $9 million. The Company recognized an after tax gain of approximately $5 million on the sale of Pogo Hungary.

The Thailand Entities and Pogo Hungary are classified as discontinued operations in the Company s financial statements for all periods presented. The summarized financial results and financial position data of the discontinued operations were as follows (amounts expressed in thousands):

Operating Results Data

	Year Ended December 31,		
	2005	**2004**	**2003**
Revenues	$ 252,840	$ 335,291	$ 303,491
Costs and expenses	(126,496)	(237,097)	(163,388)
Other income	4,962	308	2,520
Income before income taxes	131,306	98,502	142,623
Income taxes	(78,456)	(85,783)	(82,751)
Income before gain from discontinued operations, net of tax	52,850	12,719	59,872
Gain on sale, net of tax of $9,736	407,784		
Income from discontinued operations, net of tax	$ 460,634	$ 12,719	$ 59,872

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Financial Position Data

	December 31, 2004
Assets of Discontinued Operations	
Current Investments	$ 135,000
Accounts receivable	36,876
Inventories	13,800
Other current assets	1,408
Total current assets	187,084
Property, plant and equipments, net	471,012
Other long-term assets	9,085
Total assets	$ 667,181
Liabilities of Discontinued Operations	
Accounts payable	$ 51,565
Income taxes payable	34,645
Other current liabilities	23,718
Total current liabilities	109,928
Deferred income tax	64,865
Asset retirement obligation	21,094
Total liabilities	$ 195,887

(10) 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 $14,000 in 2005. 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 $1,524,000 to the savings plan in 2005, $1,360,000 in 2004, and $1,233,000 in 2003.

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. During 2005, the Company contributed $4.5 million to the plan. The Company does not expect to make a contribution to the plan in 2006. 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

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 2006 are approximately $552,000.

The following two tables set forth the plans status (in thousands of dollars) as of and for the years ended December 31 of the applicable year. The Company uses a December 31 measurement date for its plans.

	Retirement Plan		Post-Retirement Medical Plan	
	2005	2004	2005	2004
Change in benefit obligation				
Benefit obligation at beginning of year	$ 36,858	$ 29,519	$ 21,202	$ 17,145
Service cost	3,394	2,631	1,371	1,385
Interest cost	2,069	1,751	1,038	1,044
Benefits paid	(2,370)	(1,302)	(422)	(356)
Actuarial loss	6,615	4,259	(1,259)	1,984
Benefit obligation at end of year	$ 46,566	$ 36,858	$ 21,930	$ 21,202
Change in plan assets				
Fair value of plan assets at beginning of year	$ 32,299	$ 32,236	$	$
Actual return on plan assets	1,566	1,729		
Employer contributions	4,500		422	356
Benefits paid	(2,370)	(1,302)	(422)	(356)
Administrative expenses	(314)	(364)		
Fair value of plan assets at end of year	$ 35,681	$ 32,299	$	$
Reconciliation of funded status				
Funded status	$ (10,885)	$ (4,559)	$ (21,930)	$ (21,202)
Unrecognized actuarial loss	20,606	13,849	3,795	5,086
Unrecognized transition (asset) or obligation				303
Unrecognized prior service cost	539	625		
Prepaid (accrued) benefit cost at year-end	$ 10,260	$ 9,915	$ (18,135)	$ (15,813)
Accumulated benefit obligation	$ 35,646	$ 28,248		

	Retirement Plan			Post-Retirement Medical Plan		
	2005	2004	2003	2005	2004	2003
Components of net periodic benefit cost						
Service cost	$ 3,393	$ 2,631	$ 2,248	$ 1,371	$ 1,385	$ 1,102
Interest cost	2,069	1,750	1,546	1,038	1,044	915
Expected return on plan assets	(2,591)	(2,639)	(2,176)			
Amortization of prior service cost	86	46	43			
Amortization of transition (asset) obligation				303	305	305
Amortization of net loss	1,197	722	1,040	32	190	64
	$ 4,154	$ 2,510	$ 2,701	$ 2,744	$ 2,924	$ 2,386

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Plan Assumptions

	Retirement Plan			Post-Retirement Medical Plan		
	2005	2004	2003	2005	2004	2003
Plan assumptions to determine benefit obligations						
Discount rate	5.50 %	5.75 %	6.00 %	5.50 %	5.75 %	6.00 %
Rate of compensation increase	5.50 %	5.50 %	4.75 %			
Plan assumptions to determine net cost						
Discount rate	5.75 %	6.00 %	6.50 %	5.75 %	6.00 %	6.50 %
Expected long-term rate of return on plan assets	8.50 %	8.50 %	8.50 %			
Rate of compensation increase	5.50 %	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 2005.

The Company determines the discount rate used to measure plan liabilities as of the December 31 measurement date for the retirement plan. The discount rate reflects the current rate at which the associated liabilities could be effectively settled at the end of the year. In determining this rate, the Company reviews rates of return on fixed-income investments of similar duration to the liabilities in the plan that receive high, investment grade ratings by recognized ratings agencies. Using this methodology, the Company determined a discount rate of 5.50% to be appropriate as of December 31, 2005, which is a reduction of 0.25 percentage points from the rate used as of December 31, 2004.

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

Year Ending December 31,	Expected Benefit Payment
2006	$ 4,153,874
2007	3,025,019
2008	4,210,836
2009	4,194,414
2010	4,056,835
Next 5 Years	27,289,415

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Asset Category	Target	Actual as of December 31, 2005	2004
Equity securities	100 %	87 %	99 %
Debt securities	0 %	0 %	0 %
Real estate	0 %	0 %	0 %
Other	0 %	13 %	1 %
Total	100 %	100 %	100 %

For measurement purposes related to the Company s post-retirement medical plan, a 10% 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 11% 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 2005	$ 503	$ (397)
Effect on year-end 2005 postretirement benefit obligation	$ 4,058	$ (3,251)

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 2005 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.

(11) 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 of Company common stock available for future issuance was 3,637,057, 3,975,757and 2,297,657 as of December 31, 2005, 2004 and 2003, respectively. Stock options granted during and after

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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
2005	351,800	$ 19,528,106
2004	303,400	$ 13,164,429
2003	144,000	$ 6,045,840

The number of unvested shares of restricted stock was 630,600, 403,900 and 157,019 as of December 31, 2005, 2004 and 2003, respectively.

Restricted Stock Units

On November 1, 2005 the Company awarded 135,000 Restricted Stock Units (the Units) to certain employees of Northrock. The Units vest ratably over a three year period. Vested Units are payable in cash in an amount equal to the fair market value of the Company s common stock for the five-day trading period ending on the vesting date. The Company recognizes compensation expense and a liability based on the average fair market value of Company common stock for the last five trading days of the period. For the year ended December 31, 2005, the Company recognized compensation expense of $370,440 related to the Units.

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Stock Options

A summary of the status of the Company s stock option activity as of December 31, 2005, 2004 and 2003, and changes during the years ended on those dates is presented below:

	Number of Awards	Weighted Average Exercise Price
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
Outstanding, December 31, 2004	2,145,336	$ 30.00
Exercised in 2005	(352,767)	$ 31.66
Canceled in 2005	(10,333)	$ 26.09
Outstanding, December 31, 2005	1,782,236	$ 29.69
Exercisable, December 31, 2005	1,635,901	$ 28.51
Weighted-average fair value of options granted during 2005		N/A

The following table summarizes information about stock options outstanding at December 31, 2005

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	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	47,500	1,200	$ 18.30	47,500	$ 18.30
$20.31 to $24.77	655,101	1,884	$ 23.27	655,101	$ 23.27
$25.38 to $29.78	638,500	2,335	$ 29.59	638,500	$ 29.59
$31.18 to $33.94	54,000	1,798	$ 32.03	54,000	$ 32.03
$36.00	30,000	154	$ 36.00	30,000	$ 36.00
$40.63 to $43.46	332,134	2,419	$ 41.83	205,800	$ 41.71
$45.89 to $49.48	25,001	3,049	$ 48.58	5,000	$ 48.93
Total	1,782,236	2,112	$ 29.69	1,635,901	$ 28.51

(12) Commodity Derivatives and Hedging Activities

During the year ended December 31, 2005, the Company recognized $11,323,000 of pre-tax losses related to settled contracts in its oil and gas revenues from its price hedge contracts. The Company also recognized a pre-tax loss of $1,314,000 due to ineffectiveness on these hedge contracts during the year ended December 31, 2005. 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 from its price hedge contracts, which are included in oil and gas revenues. Net unrealized losses on derivative instruments of $52,952,000, net of deferred taxes of $30,437,000, have been reflected as a component of other comprehensive income for the year ended December 31, 2005. Based on the fair market value of the hedge contracts as of December 31, 2005, the Company would reclassify additional pre-tax losses of approximately $46,805,000 (approximately $29,721,000 after taxes) from accumulated other comprehensive loss (shareholders equity) to net income during the next twelve months.

As of December 31, 2005, the Company held various derivative instruments. During 2004 and 2005, 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

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2005 are as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price Floor	Ceiling	Fair Value of Liability
Natural Gas Contracts (MMBtu) (a)				
Collar Contracts:				
January 2006 - December 2006	5,475	$ 5.00	$ 7.50	$ (18,527,528)
January 2006 - December 2006	1,825	$ 5.50	$ 8.25	$ (5,106,509)
January 2006 - December 2006	3,650	$ 5.75	$ 8.27	$ (10,053,301)
January 2006 - December 2006	10,950	$ 6.00	$ 13.50	$ (4,942,274)
January 2006 - December 2006	1,825	$ 6.00	$ 13.55	$ (809,200)
January 2006 - December 2006	3,650	$ 6.00	$ 13.60	$ (1,589,865)
January 2006 - December 2006	10,950	$ 6.00	$ 14.00	$ (4,134,399)
January 2007 - December 2007	5,475	$ 6.00	$ 12.00	$ (5,536,823)
January 2007 - December 2007	9,125	$ 6.00	$ 12.15	$ (8,878,679)
January 2007 - December 2007	3,650	$ 6.00	$ 12.20	$ (3,505,893)
January 2007 - December 2007	9,125	$ 6.00	$ 12.50	$ (8,106,668)
Crude Oil Contracts (Barrels)				
Collar Contracts:				
January 2006 - December 2006	1,460,000	$ 50.00	$ 78.00	$ (976,728)
January 2006 - December 2006	365,000	$ 50.00	$ 79.00	$ (195,932)
January 2006 - December 2006	1,460,000	$ 50.00	$ 81.00	$ (439,482)
January 2006 - December 2006	365,000	$ 50.00	$ 81.04	$ (108,279)
January 2006 - December 2006	1,825,000	$ 50.00	$ 82.00	$ (357,749)
January 2007 - December 2007	1,460,000	$ 50.00	$ 75.00	$ (3,463,645)
January 2007 - December 2007	365,000	$ 50.00	$ 75.25	$ (842,944)
January 2007 - December 2007	3,650,000	$ 50.00	$ 77.50	$ (6,439,226)

(a) MMBtu means million British Thermal Units.

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Although all of the Company s collars are effective as economic hedges, the forecasted shut-in hydrocarbon production from the Company s Gulf of Mexico properties (resulting primarily from hurricane activity during the third quarter of 2005) caused certain of the gas and crude oil collar contracts to lose their qualification for hedge accounting under SFAS 133. As a result, the Company reclassified $18.7 million of previously deferred losses from accumulated other comprehensive income to Commodity derivative expense in the income statement during the third quarter of 2005. Additionally, the Company now recognizes all future changes in the fair value of these collar contracts in the consolidated statement of income for the period in which the change occurs under the caption Commodity derivative expense. As of December 31, 2005, the Company had the following collar contracts that no longer qualify for hedge accounting:

Contract Period and Type of Contract	**Volume**	**NYMEX Contract Price Floor**	**Ceiling**	**Fair Value of Liability**
Natural Gas Contracts (MMBtu)				
Collar Contracts:				
January 2006 - November 2006	1,825	$ 5.50	$ 8.25	$ (5,034,443)

(13) Acquisitions

On September 27, 2005, the Company completed the acquisition of Northrock for approximately $1.7 billion in cash. The Company purchased all of the outstanding shares of Northrock pursuant to a share purchase agreement that was entered into on July 8, 2005. As of September 27, 2005, Northrock owned approximately 292,000 net producing acres, plus approximately 950,000 net acres of undeveloped leasehold. Northrock s activities are concentrated in Saskatchewan and Alberta with key exploration plays in Canada s Northwest Territories, British Columbia and the Alberta Foothills. The Company acquired Northrock primarily to strengthen its position in North American exploration and development properties. The following is a calculation and allocation of purchase price to the acquired assets and liabilities based on their relative fair values:

CALCULATION OF PURCHASE PRICE (IN THOUSANDS)	
Cash paid, including transaction costs	$ 1,737,464
Plus fair market value of liabilites assumed:	
Other liabilites	97,123
Asset retirement obligation	38,810
Deferred income taxes	771,558
Total purchase price for assets acquired	$ 2,644,955
ALLOCATION OF PURCHASE PRICE (IN THOUSANDS)	
Proved oil and gas properties	$ 1,715,777
Unproved oil and gas properties	809,860
Other assets	119,318
Total	$ 2,644,955

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The purchase price allocation noted above is subject to change based on the Company s final analysis of the oil and gas properties and tax attributes it has acquired, which is expected to be completed in the first quarter of 2006.

In addition to the Northrock acquisition, during 2005 the Company also completed two corporate acquisitions in Canada for cash consideration totaling approximately $32.9 million and six other producing property acquisitions for cash consideration totaling approximately $51million. The Company recorded the estimated fair value of assets and liabilities on the two corporate transactions which consisted primarily of $50 million of oil and gas properties and deferred tax liabilities of $15.8 million. No goodwill was recorded for these transactions.

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 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 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.

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Pro Forma Information

The following summary presents unaudited pro forma consolidated results of operations for the three years ended December 31, 2005 for the Company s continuing operations as if the acquisitions of Northrock and the corporations had each occurred as of January 1, 2003. The pro forma results are for illustrative purposes only and include adjustments in addition to the pre-acquisition historical results of Northrock and the corporations, such as increased depreciation, depletion and amortization expense resulting from the allocation of fair value to oil and gas properties acquired, increased interest expense on acquisition debt and the related tax effects of these adjustments. 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, 2005	2004	2003
	(Unaudited)		
Pro Forma:			
Revenues	$ 1,531,066	$ 1,380,893	$ 1,203,580
Income before cumulative effect of change in accounting principle	330,487	266,063	248,173
Net income	330,487	266,063	247,806
Earnings per share:			
Basic			
Income before cumulative effect of change in accounting principle	$ 5.47	$ 4.17	$ 3.97
Net income	$ 5.47	$ 4.17	$ 3.96
Diluted			
Income before cumulative effect of change in accounting principle	$ 5.42	$ 4.13	$ 3.87
Net income	$ 5.42	$ 4.13	$ 3.87

(14) 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.

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Activity related to the Company s ARO during the years ended December 31, 2005 and 2004 is as follows (in thousands):

	Year Ended December 31, 2005		2004	
Initial ARO as of January 1,	$ 74,046		$ 58,509	
Liabilities incurred during period	41,872	(a)	15,569	(a)
Liabilities settled during period	(7,145	)	(3,595	)
Revisions to previous estimate	39,672	(b)	(1,239	)
Accretion expense	7,884		4,802	
Balance of ARO as of December 31,	$ 156,329		$ 74,046	
Less: Current portion of ARO as of December 31,	(6,955	)		
Long term portion of ARO as of December 31,	$ 149,374		$ 74,046	

(a) $39.1 million and $14.1 million of this amount relates to acquistions during 2005 and 2004, respectively.

(b) Related primarily to increased estimated future service costs based on substantial inflation in the pricing environment during 2005.

For the years ended December 31, 2005, 2004, and 2003, the Company recognized depreciation expense related to its ARC of $4,529,000, $984,000 and $2,867,000, respectively. The Company recognized $3,989,000 of accretion expense in the year ended December 31, 2003. As a result of the adoption of SFAS 143 on January 1, 2003, the Company recorded a $47,893,000 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). This after-tax charge includes the effect on the Company s discontinued operations.

(15) Fair Value of Financial Instruments

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

Cash and Cash Equivalents

Fair value is carrying value.

Receivables and Payables

Fair value is approximately carrying value.

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2005 and 2004 based on the market value interest rates.
LIBOR Rate Advances	Fair value is carrying value as of December 31, 2005 and 2004 based on the market value interest rates.
2011 Notes	Fair value is 104.1% and 108.1% of carrying value as of December 31, 2005 and 2004, based on quoted market value.
2015 Notes	Fair value is 97.1% of carrying value as of December 31, 2005, based on quoted market value.
2017 Notes	Fair value is 97.1% of carrying value as of December 31, 2005, based on quoted market value.

The carrying value and estimated fair value of the Company s financial instruments at December 31, 2005 and 2004 (in thousands of dollars) are as follows:

	2005		**2004**	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
Cash and cash equivalents	$ 57,749	$ 57,749	$ 86,456	$ 86,456
Receivables	$ 218,749	$ 218,749	$ 141,341	$ 141,341
Payables	$ (304,460)	$ (304,460)	$ (148,738)	$ (148,738)
Debt:				
Bank revolving credit agreement loans	$ (606,000)	$ (606,000)	$ (515,000)	$ (515,000)
LIBOR Rate Advances	$ (40,000)	$ (40,000)	$ (40,000)	$ (40,000)
2011 Notes	$ (200,000)	$ (208,250)	$ (200,000)	$ (216,250)
2015 Notes	$ (297,452)	$ (291,375)	$	$
2017 Notes	$ (500,000)	$ (485,625)	$	$

The Company occasionally enters into hedging contracts to minimize the impact of oil and gas price fluctuations. See Note 12 for a further discussion of these contracts.

POGO PRODUCING COMPANY & SUBSIDIARIES
UNAUDITED SUPPLEMENTARY FINANCIAL AND RESERVES DATA

Oil and Gas Producing Activities

The results of operations from oil and gas producing activities (expressed in thousands) exclude non-oil and gas revenues, corporate 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 pre-tax operating results with adjustments for permanent differences. Except as noted, all of the Company s oil and gas producing activities were conducted in the United States during 2004 and 2003

	2005 Total Company	United States	Canada	Other International
Revenues	$ 1,216,247	$ 1,082,065	$ 134,182	$
Lease operating expense	(153,659)	(135,969)	(17,690)	
Exploration expense	(26,473)	(14,047)	(3,397)	(9,029)(a)
Dry hole and impairment expense	(87,170)	(82,217)	(4,953)	
Depreciation, depletion and amortization expense	(307,109)	(256,579)	(50,530)	
Production and other taxes	(59,527)	(56,783)	(2,744)	
Transportation and accretion	(27,124)	(24,983)	(2,141)	
Pretax operating results	555,185	511,487	52,727	(9,029)
Income tax (expense) benefit	(200,508)	(182,361)	(18,147)	
Operating results	$ 354,677	$ 329,126	$ 34,580	$ (9,029)

	2004	2003
Revenues	$ 973,083	$ 856,074
Lease operating expense	(100,506)	(81,731)
Exploration expense	(21,739)	(6,899)
Dry hole and impairment expense	(61,634)(b)	(30,673)
Depreciation, depletion and amortization expense	(248,431)	(226,607)
Production and other taxes	(44,104)	(23,735)
Transportation and accretion	(19,488)	(16,949)
Pretax operating results	477,181	469,480
Income tax (expense) benefit	(175,576)	(170,750)
Operating results	$ 301,605	$ 298,730

(a) Related to New Zealand.

(b) Included is $5,551 related to the Danish North Sea.

POGO PRODUCING COMPANY & SUBSIDIARIES
UNAUDITED SUPPLEMENTARY FINANCIAL AND RESERVES DATA (Continued)

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

	2005 Total Company	United States	Canada	Other International
Costs incurred (capitalized unless otherwise indicated):				
Property acquisition				
Proved	$ 1,832,897	$ 45,981	$ 1,786,916	$
Unproved	880,859	50,843	830,016	
Exploration				
Capitalized	139,206	130,079	9,127	
Expensed	26,473	14,013	3,397	9,063
Development	220,119	164,194	55,796	129
Asset retirement cost	53,183	3,256	49,927	
Total oil and gas costs incurred	$ 3,152,737	$ 408,366	$ 2,735,179	$ 9,192
Provision for depreciation, depletion and amortization	$ 307,109	$ 256,579	$ 50,530	$

	2004		2003	
Property acquisition				
Proved	$ 612,975		$ 182,660	
Unproved	26,904		12,403	
Exploration				
Capitalized	62,500	(a)	43,499	
Expensed	21,739		6,832	
Development	228,473		135,424	
Asset retirement cost	14,330		49,706	(b)
Total oil and gas costs incurred	$ 966,921		$ 430,524	
Provision for depreciation, depletion and amortization	$ 248,431		$ 226,607	

(a) Includes $5,551 of costs related to the Danish North Sea.

(b) Includes $47,893 of cumulative asset retirement cost recorded to adopt the provisions of SFAS 143 on January 1, 2003.

POGO PRODUCING COMPANY & SUBSIDIARIES
UNAUDITED SUPPLEMENTARY FINANCIAL AND RESERVES DATA (Continued)

The following information regarding estimates of the Company s proved oil and gas reserves, which are located onshore in the United States and Canada and offshore in United States waters of the Gulf of Mexico is based on reports prepared by Ryder Scott Company, L.P. and reports prepared by the Company and reviewed by Ryder Scott Company Canada 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	Canada
Proved Reserves as of December 31, 2002	80,092,262	80,092,262	
Revisions of previous estimates	6,338,668	6,338,668	
Extensions, discoveries and other additions	2,982,400	2,982,400	
Purchase of properties	4,301,200	4,301,200	
Estimated 2003 production	(16,162,000)	(16,162,000)	
Proved Reserves as of December 31, 2003	77,552,530	77,552,530	
Revisions of previous estimates	5,012,763	5,012,763	
Extensions, discoveries and other additions	1,727,761	1,727,761	
Purchase of properties	13,775,000	13,775,000	
Sale of properties	(1,832,000)	(1,832,000)	
Estimated 2004 production	(12,370,000)	(12,370,000)	
Proved Reserves as of December 31, 2004	83,866,054	83,866,054	
Revisions of previous estimates	5,513,972	5,537,272	(23,300)
Extensions, discoveries and other additions	4,884,697	1,801,097	3,083,600
Purchase of properties	60,688,379	588,379	60,100,000
Estimated 2005 production	(10,912,237)	(9,554,925)	(1,357,312)
Proved Reserves as of December 31, 2005	144,040,865	82,237,877	61,802,988
Proved Developed Reserves as of:			
December 31, 2002	74,041,149	74,041,149	
December 31, 2003	67,391,031	67,391,031	
December 31, 2004	72,968,008	72,968,008	
December 31, 2005	118,573,719	63,160,705	55,413,014

POGO PRODUCING COMPANY & SUBSIDIARIES
UNAUDITED SUPPLEMENTARY FINANCIAL AND RESERVES DATA (Continued)

Estimates of Proved Reserves

Natural Gas (MMcf)

	Total Company	United States	Canada
Proved Reserves as of December 31, 2002	713,906	713,906	
Revisions of previous estimates	5,686	5,686	
Extensions, discoveries and other additions	65,095	65,095	
Purchase of properties	129,119	129,119	
Estimated 2003 production	(76,802)	(76,802)	
Proved Reserves as of December 31, 2003	837,004	837,004	
Revisions of previous estimates	(16,357)	(16,357)	
Extensions, discoveries and other additions	33,610	33,610	
Purchase of properties	172,022	172,022	
Sale of properties	(2,888)	(2,888)	
Estimated 2004 production	(89,410)	(89,410)	
Proved Reserves as of December 31, 2004	933,981	933,981	
Revisions of previous estimates	7,234	6,280	954
Extensions, discoveries and other additions	61,709	29,063	32,646
Purchase of properties	266,110	6,500	259,610
Estimated 2005 production	(91,309)	(84,526)	(6,783)
Proved Reserves as of December 31, 2005	1,177,725	891,298	286,427
Proved Developed Reserves as of:			
December 31, 2002	600,255	600,255	
December 31, 2003	702,836	702,836	
December 31, 2004	769,753	769,753	
December 31, 2005	906,005	685,301	220,704

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.

4. The cash flows are discounted at 10% per annum.

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.

	Year Ended December 31, 2005 Total Company	United States	Canada
Future gross revenues	$ 16,504,944	$ 11,670,396	$ 4,834,548
Future production costs	(3,754,999)	(2,585,215)	(1,169,784)
Future development and abandonment costs	(914,104)	(709,555)	(204,549)
Future net cash flows before income taxes	11,835,841	8,375,626	3,460,215
Discount at 10% per annum	(5,215,283)	(3,709,154)	(1,506,129)
Discounted future net cash flows before income taxes	6,620,558	4,666,472	1,954,086
Future income taxes, net of discount at 10% per annum	(2,057,713)	(1,445,038)	(612,675)
Standardized measure of discounted future net cash flows related to proved oil and gas reserves	$ 4,562,845	$ 3,221,434	$ 1,341,411

	Year Ended December 31, 2004	2003
Future gross revenues	$ 8,850,237	$ 6,912,547
Future production costs	(2,123,530)	(1,417,118)
Future development and abandonment costs	(437,117)	(324,813)
Future net cash flows before income taxes	6,289,590	5,170,616
Discount at 10% per annum	(2,650,272)	(2,241,953)
Discounted future net cash flows before income taxes	3,639,318	2,928,663
Future income taxes, net of discount at 10% per annum	(1,080,607)	(919,540)
Standardized measure of discounted future netcash flows related to proved oil and gas reserves	$ 2,558,711	$ 2,009,123

POGO PRODUCING COMPANY & SUBSIDIARIES

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

The following are the principal sources of change in the standardized measure of discounted future net cash flows.

	For the Year Ended December 31, 2005		
	Total Company	**United States**	**Canada**
Beginning balance	$ 2,558,711	$ 2,558,711	$
Revisions to prior years proved reserves:			
Net changes in prices and production costs	1,528,299	1,528,299	
Net changes due to revisions in quantity estimates	142,471	150,026	(7,555)
Net changes in estimates of future development costs	(334,605)	(334,605)	
Accretion of discount	363,932	363,932	
Changes in production rate and other	215,382	(154,108)	369,490
Total revisions	1,915,479	1,553,544	361,935
New field discoveries and extensions, net of future production and development costs	339,394	145,537	193,857
Purchases of properties	1,542,005	32,207	1,509,798
Sales of oil and gas produced, net of production costs	(976,009)	(864,505)	(111,504)
Previously estimated development costs incurred	160,371	160,371	
Net change in income taxes	(977,106)	(364,431)	(612,675)
Net change in standardized measureof discounted future net cash flows	2,004,134	662,723	1,341,411
Ending balance	$ 4,562,845	$ 3,221,434	$ 1,341,411

	For the Years Ended December 31,	
	2004	**2003**
Beginning balance	$ 2,009,123	$ 1,714,788
Revisions to prior years proved reserves:		
Net changes in prices and production costs	631,060	434,060
Net changes due to revisions in quantity estimates	39,661	113,329
Net changes in estimates of future development costs	(154,659)	(21,781)
Accretion of discount	292,866	249,556
Changes in production rate and other	(51,192)	(182,172)
Total revisions	757,736	592,992
New field discoveries and extensions, net of future production and development costs	126,167	241,946
Purchases of properties	596,173	289,484
Sales of properties	(58,570)	
Sales of oil and gas produced, net of production costs	(808,986)	(737,628)
Previously estimated development costs incurred	98,135	46,311
Net change in income taxes	(161,067)	(138,770)
Net change in standardized measure of discounted future net cash flows	549,588	294,335
Ending balance	$ 2,558,711	$ 2,009,123

Quarterly Results Unaudited

Summaries of the Company s results of operations by quarter for the years 2005 and 2004 are as follows:

	Quarter Ended Mar. 31	June 30	Sept. 30	Dec. 31
	(Expressed in thousands, except per share amounts)			
2005				
Revenues	$ 255,746	$ 274,564	$ 275,812	$ 419,577
Gross profit(a)	$ 92,424	$ 144,757	$ 152,200	$ 206,321
Income from continuing operations	$ 39,509	$ 73,978	$ 61,903	$ 114,679
Income (loss) from discontinued operations, net of tax	$ 19,727	$ 29,461	$ 411,625 (c)	$ (179)
Net income	$ 59,236	$ 103,439	$ 473,528	$ 114,500
Basic earnings per share(b):				
Income from continuing operations	$ 0.62	$ 1.23	$ 1.04	$ 1.98
Income (loss) from discontinued operations	$ 0.31	$ 0.48	$ 6.92	$
Basic earnings per share	$ 0.93	$ 1.71	$ 7.96	$ 1.98
Diluted earnings per share(b):				
Income from continuing operations	$ 0.63	$ 1.22	$ 1.03	$ 1.96
Income (loss) from discontinued operations	$ 0.30	$ 0.48	$ 6.86	$
Diluted earnings per share	$ 0.93	$ 1.70	$ 7.89	$ 1.96
2004				
Revenues	$ 235,133	$ 250,697	$ 259,711	$ 242,147
Gross profit(a)	$ 125,183	$ 136,991	$ 132,748	$ 93,419
Income from continuing operations	$ 66,701	$ 67,080	$ 69,004	$ 46,250
Income (loss) from discontinued operations, net of tax	$ 4,939	$ (1,891)	$ 17,608	$ (7,937)
Net income	$ 71,640	$ 65,189	$ 86,612	$ 38,313
Basic earnings per share(b):				
Income from continuing operations	$ 1.05	$ 1.05	$ 1.08	$ 0.72
Income (loss) from discontinued operations	$ 0.08	$ (0.03)	$ 0.28	$ (0.12)
Basic earnings per share	$ 1.13	$ 1.02	$ 1.36	$ 0.60
Diluted earnings per share(b):				
Income from continuing operations	$ 1.04	$ 1.04	$ 1.07	$ 0.72
Income (loss) from discontinued operations	$ 0.08	$ (0.03)	$ 0.28	$ (0.13)
Diluted earnings per share	$ 1.12	$ 1.01	$ 1.35	$ 0.59

(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.

(c) Includes approximately $403 million of after-tax gain on the sale of the Company s Thailand operations.

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 s management has evaluated, as of the end of the period covered by this report, with the supervision and participation of its Chairman, President and Chief Executive Officer and its Senior Vice President and Chief Financial Officer, the effectiveness of the Company s disclosure controls and procedures as defined by Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934. Based on that evaluation, such officers concluded that the disclosure controls and procedures were effective as of the date of that evaluation.

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, 2005. The Company excluded the Canadian division from our assessment of internal control over financial reporting as of December 31, 2005 because the division was formed with the acquisition of Northrock Resources Ltd. in a purchase business combination on September 27, 2005. The Canadian division is a wholly-owned subsidiary of the Company whose total assets and total revenues represent 49% and 11%, respectively, of the related consolidated financial statement amounts, as of and for the year ended December 31, 2005.

The Company s management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005 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.

None.

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 25, 2006, to be filed within 120 days of December 31, 2005 pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended (the Company s 2006 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 2006 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 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 2006 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 2006 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 2006 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:

*2.1	Share Purchase Agreement dated July 8, 2005 among Unocal Canada Limited, Unocal Canada Alberta Hub Limited, Unocal Corporation, Pogo Canada, ULC and Pogo Producing Company (a copy of any omitted schedule will be furnished supplementally to the Commission upon request) (Exhibit 10.1, Current Report on Form 8-K filed July 12, 2005, File No. 1-7792).
*2.2	Stock Purchase Agreement dated as of June 17, 2005 among Pogo Producing Company and Pogo Overseas Production B.V., as sellers, PTTEP Offshore Investment Company Limited and Mitsui Oil Exploration Co., Ltd., as purchasers, and PTT Exploration and Production Public Company Limited, as guarantor for PTTEP Offshore Investment Company Limited (a copy of any omitted schedule will be furnished supplementally to the Commission upon request) (Exhibit 2.1, Quarterly Report on Form 10-Q for the quarter ended June 30, 2005, File No. 1-7792).
*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. 1-7792).
*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	Indenture, dated as of March 29, 2005 between Pogo Producing Company and The Bank of New York Trust Company, N.A., as Trustee (Exhibit 4.1, Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, File No. 1-7792).
*4.2	Form of 6.625% Senior Subordinated Note (Exhibit 4.1, Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, File No. 1-7792).
*4.3	Registration Rights Agreement dated March 29, 2005, by and among Pogo Producing Company and the parties thereto (Exhibit 4.3, Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, File No. 1-7792).
*4.4	Indenture dated as of September 23, 2005 between Pogo Producing Company and The Bank of New York Trust Company, N.A. (Exhibit 4.1, Current Report on Form 8-K filed September 29, 2005, File No. 1-7792).
*4.5	Form of 6.875% Senior Subordinated Note (Exhibit 4.1, Current Report on Form 8-K filed September 29, 2005, File No. 1-7792).
*4.6	Registration Rights Agreement dated as of September 23, 2005 among Pogo Producing Company and the initial purchasers named therein (Exhibit 4.2, Current Report on Form 8-K filed September 29, 2005, File No. 1-7792).
*4.7	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).

*4.8 First Amendment to Credit Agreement, dated as of August 31, 2005 but effective as of September 27, 2005, among Pogo Producing Company, the various financial institutions which are or may become parties to the Credit Agreement, as amended thereby (collectively, the Lenders), Bank of Montreal, as administrative agent for the Lenders, Bank of America, N.A., Toronto Dominion (Texas) LLC and BNP Paribas, as Co-Syndication Agents for the Lenders, Wachovia Bank, National Association, as Documentation Agent for the Lenders, and Citibank, N.A. and The Bank of Nova Scotia, as managing agents for the Lenders (Exhibit 4.3, Current Report on Form 8-K filed September 29, 2005, File No. 1-7792).

*4.9 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).

*4.10 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).

*4.11 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 10.34, 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	Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Paul G. Van Wagenen, dated August 1, 2005.
10.9	Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Stephen R. Brunner, dated August 1, 2005.
10.10	Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Jerry A. Cooper, dated August 1, 2005.
10.11	Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and John O. McCoy, Jr., dated August 1, 2005.
10.12	Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and David R. Beathard, dated August 1, 2005.
10.13	Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Radford P. Laney, dated August 1, 2005.
10.14	Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and J. Don McGregor, dated August 1, 2005.
10.15	Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Gerald A. Morton, dated August 1, 2005.
10.16	Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and James P. Ulm, II, dated August 1, 2005.
10.17	Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Bruce E. Archinal, dated August 1, 2005.
10.18	Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Michael J. Killelea, dated August 1, 2005.
*10.32	Form of Restricted Stock Award Agreement Under Incentive Plans (Exhibit 10.2, Current Report on Form 8-K filed August 1, 2005, 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	Pogo Producing Company Retention Incentive Plan effective September 27, 2005 (Exhibit 10.4, Quarterly Report on Form 10-Q for the quarter ended September 30, 2005, File No. 1-7792).
12.1	Statement showing computation of ratios of earnings to fixed charges.
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 Ryder Scott Company - Canada
23.4	Consent of Miller and Lents, Ltd.
24	Powers of Attorney from each director of Pogo Producing Company whose signature is affixed to this Form 10-K for year ended December 31, 2005.
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, 2005.
99.2	Summary Report of Ryder Scott Company Canada for the year ended December 31, 2005.
99.3	Summary Report of Miller and Lents, Ltd. for the year ended December 31, 2005.
*99.4	Summary Report of Ryder Scott Company, L.P. for the year ended December 31, 2004 (Exhibit 99.1, Annual Report on Form 10-K for the year ended December 31, 2004).
*99.5	Summary Report of Miller and Lents, Ltd. for the year ended December 31, 2004 (Exhibit 99.2, Annual Report on Form 10-K for the year ended December 31, 2004).
*99.6	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).
*99.7	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).

* 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 2, 2006

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, 2006.

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/ CHARLES G. GROAT **Charles G. Groat**	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*	