POGO PRODUCING CO
Form 10-K
March 01, 2007

# 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, 2006**

**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**<br>(State or other jurisdiction of incorporation or organization) | **74-1659398**<br>(I.R.S. Employer Identification No.) |
| **5 Greenway Plaza, P.O. Box 2504, Houston, Texas**<br>(Address of principal executive offices) | **77252-2504**<br>(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<br>NYSE Arca |
| 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, 2006, the aggregate market value of the registrant s common stock held by non-affiliates of the registrant was approximately $2,675,000,000 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 23, 2007** |
|---|---|
| Common Stock, $1.00 par value per share | 58,480,047 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 May 15, 2007 | 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, 2006 (this Annual Report ) of Pogo Producing Company (the Company ) include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements included or incorporated by reference herein, other than statements of historical fact, are forward-looking statements. In some cases, you can identify the Company s forward-looking statements by the words anticipate, estimate, expect, objective, projection, forecast, goal, and similar expressions. Su forward-looking 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, results of operations, 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
- strategic transactions, including the sale of part or all of the Company, or changes to the Company s business plan, that may result from its strategic alternative process

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 Vietnam and New Zealand. As of December 31, 2006, the Company had interests in approximately 4,800,000 gross leasehold acres in major oil and gas provinces in North America, approximately 6,354,000 gross acres in New Zealand and approximately 1,480,000 gross acres in Vietnam. 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, 2006, approximately 94% 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. The operating regions are its Canadian Operations, its Western U.S. Region, which is active in the Permian Basin area of West Texas and Southeast New Mexico, the Panhandle of Texas, the San Juan Basin in New Mexico and the Wind River Basin 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 its Asia and Pacific Region, which has responsibility for the Company s operations in New Zealand and Vietnam. The New Ventures Group is primarily responsible for identifying new projects and opportunities for the Company outside the United States.

On May 31, 2006, the Company closed the sale of an undivided 50% interest in each of Pogo s Gulf of Mexico oil and gas leasehold interests to Mitsui & Co., Ltd., Mitsui & Co. (U.S.A.), Inc. and Mitsui Oil Exploration Co., Ltd. for approximately $448.8 million. On May 2, 2006, the Company completed the acquisition of Latigo Petroleum, Inc. ( Latigo ) for approximately $764.9 million. Latigo s activities are concentrated in the Permian Basin and the Panhandle of Texas.

*Recent Developments*

On February 15, 2007, the Company issued a press release confirming that its Board of Directors had previously initiated the exploration of a range of strategic alternatives to enhance shareholder value, and was continuing to do so, including the possible sale or merger of the Company, the sale of its Canadian, Gulf Coast, Gulf of Mexico or other significant assets, and changes to its business plan. The Company also announced that it had retained Goldman, Sachs & Co. and TD Securities Inc. as financial advisors for the process.

**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 is headquartered in

Midland, Texas, and maintains an additional office in Tulsa, Oklahoma. In addition the Company has four field offices in West Texas, three field offices in southeastern New Mexico and three 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, 2006, accounted for approximately 62% of the Company s total proved reserves, with the Gulf Coast Region and the Western U.S. Region contributing approximately 12% and 50%, respectively, of the Company s total proved reserves. During 2006, approximately 64% of the Company s natural gas production and 39% of its oil and condensate production was from its domestic onshore properties, contributing approximately 51% of the Company s consolidated oil and gas revenues.

The Los Mogotes Field, which is part of the Company s Gulf Coast Region, consists of approximately 22,420 gross acres located in South Texas. The Company owns various working interests in the Los Mogotes Field, which average approximately 71% across the field, and is the operator of a majority of those working interests. In 2006, the Company s interests in Los Mogotes produced an average of approximately 35 MMcf per day of natural gas, accounting for approximately 13% of the Company s natural gas production for the period. As of December 31, 2006, the Company s proved reserves associated with the Los Mogotes Field were 45 MBbls of oil, condensate and natural gas liquids and 97,252 MMcf of natural gas, which together represented approximately 4.4% of the Company s total proved reserves. As of that date, the Company s leasehold interests in the field included 13,329 net acres of developed lands and 1,953 net acres of undeveloped lands, with approximately 107 net producing wells and 161 gross producing wells. The map below depicts the location of the field.

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The Madden Unit, which is part of the Company s Western Region, is a federal unit operated by a third party and consists of approximately 80,000 acres in the Wind River Basin located in Central Wyoming. The Company owns various working interests in the Madden Unit, which average approximately 14% across the unit area. In 2006, the Company s interests in the Madden Unit produced an average of approximately 36 MMcf per day of natural gas, accounting for approximately 13% of the Company s natural gas production for the period. As of December 31, 2006, the Company s proved reserves associated with the Madden Unit were 59 MBbls of oil, condensate and natural gas liquids and 241,501 MMcf of natural gas, which together represented approximately 10.9% of the Company s total proved reserves. As of that date, the Company s leasehold interests in the unit included 3,094 net acres of developed lands and 7,353 net acres of undeveloped lands, with approximately 33 net producing wells and 236 gross producing wells. The map below depicts the location of the unit.

*Exploration and Development*

The Company s onshore capital and exploration expenditures for 2006 were approximately $577,400,000, excluding approximately $998,500,000 of net property acquisitions. Comparable expenditures for 2005 and 2004 were approximately $251,400,000 (excluding approximately $59,500,000 of net property acquisitions) and $196,500,000 (excluding approximately $489,600,000 of net property acquisitions), respectively. The increase in the Company s onshore capital and exploration expenditures for 2006, compared to 2005, resulted primarily from expenditures related to increased exploratory and development drilling. The Company has currently budgeted approximately $720,000,000 for capital and exploration expenditures during 2007 in its domestic onshore areas.

The Company generally conducts its onshore activities through 100% ventures as well as 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 Southeastern New Mexico for more than 27 years. In addition to those areas, in recent years the Company has expanded its exploration and production efforts to also include the Texas Panhandle, the San Juan Basin of northwest New Mexico and the Wind River Basin of Wyoming. In 2006, the Company participated in the drilling of 258 wells in all of these areas (88% of which were successfully completed). The Company believes that during recent years it has been one of the more active companies drilling for oil and natural gas in the Permian Basin of West Texas, Southeastern New Mexico and the Texas Panhandle.

During 2007, the Company plans to drill approximately 21 exploratory wells and 103 development wells in various known fields and exploratory prospects located in West Texas, southeast New Mexico, and the Texas Panhandle. Drilling objectives for these wells range in vertical depth from 4,500 feet to 17,000 feet below the surface and target numerous formations including, among others, the Grayburg, Delaware (Bell Canyon, Cherry Canyon, Brushy Canyon), Spraberry, Bone Spring, Wolfcamp, Granite Wash, Strawn, Atoka, Morrow and Mississippian and Hunton formations.

The Company also plans to continue an active development drilling program in the San Juan Basin of northwest New Mexico. Twenty wells are expected to be drilled in several prospects in this area during 2007. The primary targets are the Fruitland Coal and Dakota formations. Drilling depths are expected to range from approximately 1,500 feet to 6,500 feet.

The Company has actively participated in the exploration and development of the Madden Unit since it first acquired its non-operated working interest in 2001. The Madden Unit is characterized by gas production from multiple stratigraphic horizons of the Lower Fort Union, Lance, Mesaverde and Cody sands and the Madison dolomite. Production from the Madden Unit is typically found at depths ranging from 5,500 to 25,000 feet. Some of the gas produced from the Madden Unit requires processing by the Lost Cabin Gas Plant (in which the Company owns a partial interest) to make it pipeline quality. Of the 258 wells drilled in the Western Region in 2006, 36 of those wells were drilled in the Madden Unit. Recent drilling activity in the unit has focused on the Lower Fort Union formation, where productive zones have historically been found at depths from approximately 5,500 feet to 11,000 feet below the surface. The company expects that the unit operator will conduct a 2007 drilling program of approximately 25 to 30 wells which will target, among other objectives, the Lower Fort Union Sands and the shallower (3,500 feet) Shotgun Sands.

*Acquisition of Latigo.* On May 2, 2006, the Company acquired Latigo Petroleum, Inc. a privately owned exploration and production company, for a purchase price of approximately $764.9 million, including approximately $210 million to retire Latigo s bank debt and purchase price adjustments. As of December 31, 2006, proved reserves attributed to Latigo properties were approximately 29 MMBls of oil, condensate and natural gas liquids and 153,623 MMcf of natural gas. This acquisition included approximately 404,000 net acres of leasehold. Its development activities are concentrated in Texas, including the Collie Field in Reeves and Ward counties in West Texas, and the Courson Ranch area located primarily in Roberts and Ochiltree Counties in the Texas Panhandle. Exploration opportunities in the Panhandle have been identified in multiple areas, including on a concentration of ranches controlled by Latigo which are principally located in Roberts and Hutchinson Counties, Texas. During 2007, the company plans to drill approximately 52 exploratory and development wells on its Latigo properties.

*Gulf Coast Region.* The Company s Gulf Coast Region is actively exploring for and developing oil and gas reserves, primarily in the coastal onshore areas of Louisiana and Texas. The Region s staff is also responsible for the Company s activities in the Illinois Basin in southern Indiana and the North Dakota portion of the Williston Basin. The Company has interests in over 715,000 gross developed and undeveloped leasehold acres in this Region. During 2006, the Gulf Coast Region participated in drilling 65 wells, 82% of which were successfully completed. For 2007, the Company s budget for the Region includes participation in a total of 59 wells of which 14 are exploratory wells and 45 are development wells.

The Gulf Coast Region s development activities in 2006 were focused on its 64,000 gross acres of leasehold in South Texas Webb and Zapata Counties. The Region has been developing gas reserves primarily in its Los Mogotes, Hundido, South Hundido and Hereford Ranch Fields that produce from the Eocene Wilcox formation, found at depths generally ranging from 7,000 to 14,000 feet below the surface. The Company s working interest in these wells ranges from 49% to 100% and the Company has historically operated over 80% of its working interest in these wells. A total of 34 wells were drilled in these fields in 2006. The Company has planned an active drilling program here and has 27 locations budgeted for drilling in 2007. Identification of additional development drilling locations in these fields is an iterative and continuing process. The Company believes that as additional locations are identified there will be continued successful development of these properties in future years.

In Jefferson County, Texas, the Company is a 50% partner in an outside-operated venture to explore for Oligocene, Hackberry and Vicksburg reservoirs. Approximately 77,000 gross acres are leased or optioned and three exploratory test wells are budgeted to be drilled in 2007.

In Polk and Tyler Counties, Texas, the Company s Gulf Coast Region is exploring the Cretaceous Woodbine and Austin Chalk Formations for new oil and gas reserves. The Company owns 128 square miles of new, proprietary 3-D seismic data and interpretation of that data has yielded a number of exploratory prospects, which are generally 100% owned and operated by the Company. The Company has interests in approximately 72,000 gross acres in this area. During 2006, the Company drilled and completed two high volume Austin Chalk discovery wells.

During 2006, the Company s Gulf Coast Region participated in drilling four Miocene exploratory wells in South Louisiana that were unsuccessful. The Company expects to operate one exploratory test and participate in one outside operated exploratory test in this area in 2007. The Company is in the process of acquiring over 100 square miles of new 3-D seismic data in central South Louisiana to explore for new Miocene prospects. The Company has interests in over 51,000 gross acres in the area and it intends to maintain a 50% working interest in any prospects developed.

The Company is actively evaluating its contiguous 8,000 gross acres of leasehold in Jack and Wise Counties, Texas to determine the potential of the Mississippian Barnett Shale unconventional resource play. The Company holds a 75% working interest in this acreage. If test results warrant, the Company may drill additional wells here in 2007.

In southwest Indiana, the Company owns a 50% working interest in a Devonian New Albany Shale unconventional resource play that an industry partner operates. Approximately 253,000 gross acres are under lease. During 2006, the Company participated in drilling 13 productive gas wells. Fourteen horizontal New Albany Shale wells are connected to a central facility.

The Company s Gulf Coast Region also evaluates the Company s Mississippian Bakken Shale unconventional resource play in Williams and Dunn Counties, North Dakota. During 2006, the Company acquired a 100% working interest in over 81,000 gross acres and began drilling test wells. The Company anticipates that it will drill additional wells to appraise and develop this play in 2007.

**Domestic Offshore Operations**

*Gulf of Mexico Region.* Approximately 6% of the Company s total proved reserves as of December 31, 2006 were located in the Gulf of Mexico. During 2006, approximately 8% of the Company s natural gas production and 21% of its oil, condensate and natural gas liquids production were from the Company s domestic offshore properties and together contributed approximately 17% 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.

During 2006, the Company s wells in the Main Pass Block 61/62 Field, which is located on the continental shelf off the southeastern tip of Louisiana, produced an average of approximately 5,370 Bbls per day of oil, condensate and natural gas liquids, accounting for approximately 15% of the Company s liquid hydrocarbon production for the period. As of December 31, 2006, the Company s proved reserves for the Main Pass Block 61/62 Field were 7,858 MBbls of oil, condensate and natural gas liquids and 4,142 MMcf of natural gas, which together represented approximately 2.3% of the Company s total proved reserves. The Company is the operator of a 50% working interest in Main Pass Block 61/62 Field, subject to a 5% overriding royalty interest in Main Pass Block 61. The Company s interests are owned through federal leases administered by the Minerals Management Service ( MMS ), in which the MMS has retained a 16.67% royalty interest. As of December 31, 2006, the Company s leasehold interests in the Main Pass Block 61/62 Field included 4,995 net acres of developed lands and no undeveloped lands, with 17 net producing wells.

The Main Pass Block 61/62 Field, which was brought online by the Company in 2002, consists of a series of stratigraphic traps located on a regionally dipping slope, downdip at the Upper Miocene Shelf/Slope break. As of December 31, 2006, the Company is injecting water for both pressure support and enhanced recovery in the two larger reservoirs of the field through injection wells, while producing from 17 wells. The map below depicts the location of the field.

*Exploration and Development*

The Company s domestic offshore capital and exploration expenditures for 2006 were $47,700,000. Comparable expenditures for 2005 and 2004 were approximately $88,700,000 and $150,300,000, respectively. The decrease in the Company s domestic offshore capital and exploration expenditures for

2006 were due in part to the sale of 50% of the Company s position in all offshore properties and from decreased expenditures for exploration and development wells and facilities construction. During 2006, the Company invested approximately $24,900,000 in exploration and development wells and $19,900,000 in facilities construction for its Gulf of Mexico operations. The Company has currently budgeted $37,000,000 for capital expenditures and development wells during 2007 in the Gulf of Mexico, of which $9,700,000 is budgeted for development wells and $27,300,000 for workovers, facilities and abandonment operations. The Company participated in drilling two wells during 2006 in the Gulf of Mexico Region, one of which was considered successful. At December 31, 2006, the Company held varying interests in 201 proved producing and proved shut-in 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 53 of the 84 offshore leases in which it had an interest as of December 31, 2006.

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, sea floor conditions, and type of production handling equipment.

*Sale of 50% Interest in Gulf of Mexico Properties.* On May 31, 2006, the Company completed the sale of one-half of its federal and state Gulf of Mexico oil and gas leasehold interests and related pipelines and equipment for a purchase price of $500 million, or approximately $448.8 million after customary purchase price adjustments, to MitEnergy Upstream LLC, an affiliate of Mitsui & Co., Ltd., Mitsui & Co. (U.S.A.), Inc. and Mitsui Oil Exploration Co., Ltd. The sale of the 50% interest in these properties is equivalent to approximately 8 MBbls per day of oil production and 24 MMcf per day of natural gas production, in each case as of March 31, 2006.

*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, 2006, the Company owned interests in 73 federal leases and 11 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, New Zealand and Vietnam. 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 recent acquisitions are significant and 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 $327,100,000 (excluding approximately $22,400,000 of net property acquisitions) for 2006. Expenditures for 2005 and 2004 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) and $148,900,000 (approximately $5,700,000 excluding Thailand and Hungary operations), respectively. The increase in the Company s capital and exploration expenditures for 2006 resulted primarily from increased expenditures for facilities costs and increased drilling activity.

The Company has currently budgeted approximately $258,000,000 for capital and exploration expenditures during 2007 in areas outside the United States, including approximately $250,000,000 in Canada.

**Canadian Operations**

The Company s Canadian operations are conducted through a wholly-owned subsidiary, Northrock Resources Ltd. ( Northrock ), which was acquired by the Company from Unocal Corporation on September 27, 2005 for approximately $1.7 billion. Northrock is headquartered in Calgary, Alberta, Canada and has Canadian field offices in Rocky Mountain House, Alberta, Grande Prairie, Alberta and in Estevan, Saskatchewan.

Northrock conducts its activities through joint ventures with other Canadian oil and gas companies and operates its properties using both independent contractors and field personnel.

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, 2006, accounted for approximately 32% of the Company s total proved reserves. During 2006, Northrock contributed approximately 28% of the Company s natural gas production and 40% of its crude oil, condensate and natural gas liquids production.

In addition to crude oil and natural gas reserves and production, Northrock has a significant undeveloped land base. As of December 31, 2006, Northrock had more than one million net acres of undeveloped land for future exploration purposes including almost 300,000 net acres of undeveloped land in the Northwest Territories.

*Exploration and Development*

In 2006 Northrock drilled 163 gross wells of which 152 gross wells were successfully completed, for an overall success rate of 93%. Drilling activity included 33 natural gas wells in the Sunchild/Ferrier area of West Central Alberta and 25 wells in the Mikwan/Huxley area of southern Alberta following a successful exploration program in 2005. These activities contributed significantly to the natural gas production growth that was experienced in Canada in 2006. The 2006 drilling program also included eight successful Coal Bed Methane wells in the Mikwan/Huxley area of Alberta of which five wells are expected to be tied-in by the middle of 2007.

For 2007, Northrock expects to continue an equally active exploration and development program and expects to drill 139 wells including a large scale natural gas exploration program in the Alberta foothills. The exploration and development program in Canada for 2007 will focus on various known fields in both Alberta and Saskatchewan.

In addition to exploration and development initiatives in western Canada, Northrock has an approximate 32% working interest in an exploration project in the Central Mackenzie Valley in the Northwest Territories near the route of the proposed Mackenzie Valley Gas Pipeline. For 2006, Northrock participated in drilling two wells in the Central Mackenzie Valley. The 2007 and 2008 winter exploration program is anticipated to include the acquisition of both 2-D seismic and 3-D seismic with the potential of drilling an additional well in the first quarter of 2008.

*Acquisitions*

Northrock also has an acquisition program focused on properties that compliment existing exploration and development initiatives and on identifying new areas where significant development opportunities are anticipated. In 2006, Northrock spent $34 million to acquire interests in producing properties located primarily in the Mikwan/Huxley area of Alberta. For 2007, 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. During 2006, the Company farmed-out 50% of its working interest in these three permits to two industry partners. 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. The Company and its partners have agreed to drill at least one well in 2007 with a rig that the Company has under contract. The Company also anticipates acquiring additional 3-D seismic data over a portion of its Northern Taranaki permit areas in 2007. The Company has a commitment to drill one well on each of the three licenses by February 2008 or relinquish the licenses. Production permits of up to 40 years may be applied for if a commercial field is discovered.

During 2006, the Company was granted a petroleum exploration license over approximately 21,460 square kilometers (approximately 5.31 million acres) in the offshore East Coast Basin. The primary term of this license is for five years, subject to extension for up to an additional ten years, provided that at least half of the acreage under the license has been relinquished and the permit holder has substantially complied with the terms of the permit. The Company committed to reprocess 3,800 kilometers of existing 2-D seismic data and acquire 2000 kilometers of new 2-D seismic data over the permit area within the first year of the primary term. The Company must commit to drill one well within the permit area prior to May 2008 or relinquish the license. As in the Northern Taranaki permit areas, a production permit of up to 40 years may be applied for if a commercial field is discovered.

*Vietnam.* The Company, together with a joint venture partner, entered into a Production Sharing Contract with PetroVietnam, the state oil company of Vietnam, for Block 124, which covers approximately 1.48 million acres offshore central Vietnam. The initial term of the contract is seven years, consisting of a three year primary phase during which the Company is committed to acquire, process and interpret at least 800 square kilometers of 3-D seismic data and drill two exploration wells, followed by two consecutive year optional phases. The contract may be extended to a maximum term of 35 years if a commercial field is discovered.

*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 sales 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.

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.

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 10 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, 2006, 2005 and 2004, 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 owns an approximate 13.68% interest in the Lost Cabin Gas Plant located in the Madden Unit, which currently is processing approximately 336 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 approximately 50% 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 2006, crude oil sales to Shell Trading Company and gas sales to NGX each 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, 2006, 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 in such acres or wells.

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, 2006:

| | **Developed Acreage(a)** | | **Undeveloped Acreage(b)** | |
|---|---|---|---|---|
| | **Gross** | **Net** | **Gross** | **Net** |
| Domestic Onshore | | | | |
| Louisiana | 9,999 | 4,872 | 92,092 | 88,382 |
| New Mexico | 116,886 | 86,568 | 115,405 | 74,060 |
| Texas | 429,142 | 263,173 | 570,322 | 428,846 |
| Indiana | 24,130 | 10,983 | 228,693 | 108,125 |
| Wyoming | 30,885 | 3,895 | 137,149 | 100,549 |
| Utah | 0 | 0 | 70,978 | 68,591 |
| Other | 34,663 | 13,481 | 287,968 | 177,357 |
| Total Domestic Onshore | 645,705 | 382,972 | 1,502,607 | 1,045,910 |
| Domestic Offshore | | | | |
| Louisiana | 126,176 | 27,876 | 174,595 | 78,052 |
| Texas | 11,520 | 2,643 | 11,520 | 2,016 |
| Total Domestic Offshore | 137,696 | 30,519 | 186,115 | 80,068 |
| Total Domestic | 783,401 | 413,491 | 1,688,722 | 1,125,978 |
| International | | | | |
| Canada | 654,874 | 319,998 | 1,950,162 | 1,012,256 |
| New Zealand | 0 | 0 | 6,354,000 | 5,832,000 |
| Vietnam | 0 | 0 | 1,480,000 | 1,480,000 |
| Total International | 654,874 | 319,998 | 9,784,162 | 8,324,256 |
| Total Company | 1,438,275 | 733,489 | 11,472,884 | 9,450,234 |

(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 19% of the Company s total offshore net undeveloped acreage has expiring terms in 2007 and approximately 9% of the Company s total onshore net undeveloped acreage has expiring terms in 2008.

*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.

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Average Production (Lifting) Costs per Mcfe(a): | | | |
| Located in the United States | $ 2.16 | $ 1.45 | $ 0.97 |
| Located in Canada | $ 1.63 | $ 1.47 | |
| Total Company(b) | $ 1.98 | $ 1.45 | $ 0.97 |

(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.

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*Productive Wells and Drilling Activity*

The following table shows the Company s interest in productive oil and natural gas wells as of December 31, 2006. 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** | **2,187** | **1,455.2** | **2,083** | **1,228.7** | **4,270** | **2,683.9** |
| Operated | 1,439 | 1,332.3 | 1,296 | 1,083.6 | 2,735 | 2,415.9 |
| Nonoperated | 748 | 122.9 | 787 | 145.1 | 1,535 | 268.0 |
| **Domestic Offshore** | **127** | **30.9** | **52** | **12.3** | **179** | **43.2** |
| Operated | 47 | 20.4 | 29 | 9.7 | 76 | 30.1 |
| Nonoperated | 80 | 10.5 | 23 | 2.6 | 103 | 13.1 |
| **Canada** | **1,573** | **840.0** | **724** | **363.0** | **2,297** | **1,203.0** |
| Operated | 530 | 477.0 | 366 | 279.0 | 896 | 756.0 |
| Nonoperated | 1,043 | 363.0 | 358 | 84.0 | 1,401 | 447.0 |
| **Total** | **3,887** | **2,326.1** | **2,859** | **1,604.0** | **6,746** | **3,930.1** |
| Operated | 2,016 | 1,829.7 | 1,691 | 1,372.3 | 3,707 | 3,202.0 |
| Nonoperated | 1,871 | 496.4 | 1,168 | 231.7 | 3,039 | 728.1 |

(a) One or more completions in the same bore hole are counted as one well. The data in the above table includes 35 gross (19.3 net) oil wells and 136 gross (83.6 net) natural gas wells with multiple completions.

(b) The Company was in the process of drilling a total of 59 gross (7 Canada, 52 U.S.) and 38.8 net (5.3 Canada, 33.5 U.S.) oil and natural gas wells as of December 31, 2006.

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.

| | 2006 | | 2005 | | 2004 | |
|---|---|---|---|---|---|---|
| | **Productive** | **Dry** | **Productive** | **Dry** | **Productive** | **Dry** |
| **Gross Wells:** | | | | | | |
| Domestic Onshore | | | | | | |
| Exploratory | 21 | 15 | 10 | 3 | 1 | 5 |
| Development | 258 | 29 | 204 | 12 | 248 | 9 |
| Domestic Offshore | | | | | | |
| Exploratory | 0 | 1 | 2 | 5 | 2 | 2 |
| Development | 1 | 0 | | | 8 | |
| Canada | | | | | | |
| Exploratory | 28 | 9 | 2 | 1 | | |
| Development | 124 | 2 | 37 | 3 | | |
| Total | 432 | 56 | 255 | 24 | 259 | 16 |
| **Net Wells:** | | | | | | |
| Domestic Onshore | | | | | | |
| Exploratory | 15.7 | 12.2 | 7.7 | 2.2 | 0.6 | 3.8 |
| Development | 163.1 | 17.7 | 70.2 | 5.1 | 122.4 | 4.6 |
| Domestic Offshore | | | | | | |
| Exploratory | 0.0 | 0.6 | 2.0 | 3.9 | 1.6 | 1.8 |
| Development | 0.5 | 0.0 | | | 6.2 | |
| Canada | | | | | | |
| Exploratory | 23.6 | 7.5 | 1.5 | 1.0 | | |
| Development | 73.8 | 1.5 | 21.9 | 1.9 | | |
| Total | 276.7 | 39.5 | 103.3 | 14.1 | 130.8 | 10.2 |

*Reserves*

The following table sets forth information as to the Company s net total proved and proved developed reserves as of December 31, 2006, 2005 and 2004, 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, for certain of its domestic properties acquired from Latigo, Ryder Scott Company Canada ( Ryder Scott Canada ), for all of its Canadian properties, and Miller and Lents, Ltd. ( Miller and Lents ), for certain of its onshore Gulf Coast and Rocky Mountain properties, 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 reports cover 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, 2006 | 2005 | 2004 |
|---|---|---|---|
| **Total Proved Reserves(a):** | | | |
| Oil, condensate and natural gas liquids (MBbls) | | | |
| Located in the United States | 98,718 | 82,238 | 83,866 |
| Located in Canada | 64,617 | 61,803 | |
| Total Company | 163,335 | 144,041 | 83,866 |
| Natural Gas (MMcf) | | | |
| Located in the United States | 914,657 | 891,298 | 933,981 |
| Located in Canada | 318,313 | 286,427 | |
| Total Company | 1,232,970 | 1,177,725 | 933,981 |
| Present value of estimated future net cash flows, before income taxes (in thousands) | | | |
| Located in the United States | $ 2,979,261 | $ 4,666,472 | $ 3,639,318 |
| Located in Canada | $ 1,498,958 | $ 1,954,086 | |
| Total Company | $ 4,478,219 | $ 6,620,558 | $ 3,639,318 |
| **Total Proved Developed Reserves(b):** | | | |
| Oil, condensate and natural gas liquids (MBbls) | | | |
| Located in the United States | 67,685 | 63,161 | 72,968 |
| Located in Canada | 55,918 | 55,413 | |
| Total Company | 123,603 | 118,574 | 72,968 |
| Natural Gas (MMcf) | | | |
| Located in the United States | 701,550 | 685,301 | 769,753 |
| Located in Canada | 236,791 | 220,704 | |
| Total Company | 938,341 | 906,005 | 769,753 |
| Present value of estimated future net cash flows, before income taxes (in thousands) | | | |
| Located in the United States | $ 2,515,279 | $ 3,660,148 | $ 3,122,860 |
| Located in Canada | $ 1,295,906 | $ 1,653,299 | |
| Total Company | $ 3,811,185 | $ 5,313,447 | $ 3,122,860 |

(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, the Company s proved reserves in

Thailand consisted of 32,517 MBbls and 37,307 MBbls of oil, condensate and natural gas liquids, respectively. The Company had no proved reserves in Hungary as of December 31, 2004.

(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, 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. The Company had no proved developed reserves in Hungary as of December 31, 2004.

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, 2006 (thousands) | 2005 | 2004 |
|---|---|---|---|
| Present value of estimated future net cash flows, before income taxes, of proved developed reserves | $ 3,811,185 | $ 5,313,447 | $ 3,122,860 |
| Present value of estimated future net cash flows, before income taxes, of proved undeveloped reserves | 667,034 | 1,307,111 | 516,447 |
| Present value of estimated future net cash flows, before income taxes, of total proved reserves | $ 4,478,219 | $ 6,620,558 | $ 3,639,307 |
| Future income taxes, net of discount at 10% per annum | (1,125,251 ) | (2,057,713 ) | (1,080,607 ) |
| Standardized measure of discounted future net cash flows related to proved oil and gas reserves | $ 3,352,968 | $ 4,562,845 | $ 2,558,700 |

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 cash flows, 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 15.1% of the Company s total proved liquids reserves and approximately 14.9% of the Company s proved developed liquids reserves as of December 31, 2006.

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, 2006 | 2005 | 2004 |
|---|---|---|---|
| Initial Weighted Average Price (in Dollars): | | | |
| Oil, condensate and natural gas liquids (per Bbl) | | | |
| Located in the United States | $ 55.20 | $ 57.06 | $ 40.82 |
| Located in Canada(a) | $ 44.26 | $ 42.86 | |
| Natural Gas (per Mcf) | | | |
| Located in the United States | $ 5.19 | $ 8.15 | $ 6.04 |
| Located in Canada | $ 5.49 | $ 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 net revenues from gas reserves attributable to the Company s interests, prices in effect at December 31, 2006 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 cash flows from liquids attributable to the Company s interests, prices in effect at December 31, 2006 were used and these prices were held constant through to depletion of the properties. The future net cash flows 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 cash flows, 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 2006. 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.

*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 2006, the Company incurred capital expenditures of approximately $6,382,000 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 $5,418,250 for expenditures involving environmental control facilities during 2007, 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, 2006, the Company and its subsidiaries had 566 full-time employees, including 183 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 recent acquisitions are significant and may not be successful.***

In September 2005, the Company completed the acquisition of Northrock, the largest acquisition in its history. In May 2006, the Company completed the acquisition of Latigo, another significant acquisition for the Company. The Company may not be able to realize anticipated economic, operational and other benefits from these recent acquisitions due to the following risks and difficulties, among others:

- the acquired 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 acquisitions, some of which may materially exceed its estimates;
- the Company may lose key employees on whom management is substantially dependent in the operation of Northrock s or Latigo s assets;
- the Company may lose customers, suppliers, partners and agents of Northrock or Latigo;
- the Company may experience material difficulties and additional costs in integrating Northrock s or Latigo s operations, systems and personnel with its own; and
- the Company may need to recognize additional impairment expense in the future on the unproved property acquired in the acquisitions (including interest capitalized in future periods).

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***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.

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. 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. 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. 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 s ongoing capital requirements consist primarily of the following items:

- funding its 2007 capital and exploration budget of $720 million;

- other allocations for acquisition, development, production, exploration and abandonment of oil and natural gas reserves; and

- future dividends.

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 its credit facility;
- its uncommitted money market line(s) of credit; and
- capital the Company believes it can raise through opportunistic debt and equity offerings.

The Company financed a substantial part of the Northrock acquisition utilizing cash on hand, proceeds from the offering of its 6.875% Senior Subordinated Notes due 2017 and borrowings under its revolving credit facility. In addition, the Company financed a portion of its acquisition of Latigo utilizing borrowings under its revolving credit facility. Accordingly, these acquisitions reduce the availability of those resources for other capital requirements. Moreover, the uncertainties and risks associated with future performance and revenues will ultimately determine the Company s liquidity and ability to meet anticipated capital requirements.

***Rights to repayment or acceleration of up to $2.3 billion of the Company s debt and other payments would be triggered by a change in a majority of the Board of Directors that is not approved by incumbent directors.***

On February 23, 2007, a shareholder formally notified the Company that it intends to conduct a proxy contest at the Company s 2007 annual meeting that would, if successful, result in a change in a majority of the Board of Directors. As of February 28, 2007, the Company had approximately $1.45 billion aggregate principal amount of senior subordinated notes outstanding and approximately $869 million of outstanding senior indebtedness, approximately $769 million of which was outstanding under its revolving credit facility. If there is a change in a majority of the Board of Directors not approved by a vote of two-thirds of the incumbent directors, the indentures governing the notes require the Company to offer to repurchase all outstanding notes at 101% of their principal amount and to repay all outstanding senior debt, including the credit facility, prior to repurchasing the notes (or obtain consent from the lenders allowing for such repurchase). Although such a change in a majority of the Board of Directors would not, by itself, constitute an event of default under the credit facility, failure by the Company to perform its indenture obligations would allow the lenders under the credit facility to accelerate the credit facility debt. During 2007, two series of the Company s notes, representing $800 million in aggregate principal amount, have generally traded below their principal face value, and the other two series, representing $650 million in aggregate principal amount, have generally traded above 101% of their principal amount. The Company cannot predict the actions its noteholders or lenders may take. However, the Company believes that holders whose notes were trading below the repurchase price at the time the rights were triggered would exercise their repurchase rights. Additionally, the Company believes that lenders under its credit facility and holders whose notes were trading above the repurchase price may also exercise their repayment or repurchase rights, as the case may be, to the extent they expect that the holders whose notes were trading below the repurchase price would exercise such rights or for other reasons. The Company does not have sufficient cash available to fund a repurchase of all or a substantial portion of the senior subordinated notes or to repay all or a substantial portion of outstanding debt under the credit facility.

Defaults under, or the acceleration of, the notes or credit facility could significantly and adversely affect the Company s financial position. If the Company were not able to refinance the debt, it could be required to sell substantial assets at distress prices in order to satisfy its obligations or to seek protection under the federal bankruptcy laws. Any refinancing of the Company s existing debt with new debt, if available, would likely involve substantial costs, including the premium to repurchase notes from existing holders and transaction costs associated with obtaining new debt. Such new debt may be on less favorable terms than the Company s existing debt. Refinancing may also negatively impact the Company s strategic alternatives initiative.

A change in the majority of the Board of Directors as a result of the pending proxy contest would also trigger an obligation to make payments under the Company s executive employment agreements (upon termination of employment by the executives during specified periods or in specified circumstances) and under the Company s severance and retention program.

***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. 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.

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 Company s reserve data are estimates.***

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, 2006.

**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, 2006, 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 | 60 | 1991 |
| Stephen R. Brunner | Executive Vice President Operations | 48 | 2002 |
| Jerry A. Cooper | Executive Vice President and Regional Manager Western United States | 58 | 2002 |
| John O. McCoy, Jr. | Executive Vice President and Chief Administrative Officer | 55 | 2002 |
| David R. Beathard | Senior Vice President Engineering | 48 | 2002 |
| Michael J. Killelea | Senior Vice President, General Counsel and Corporate Secretary | 44 | 2005 |
| James P. Ulm, II | Senior Vice President and Chief Financial Officer | 43 | 2002 |
| Robert C. Marlowe | Vice President Accounting | 44 | 2004 |

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. Marlowe, who joined the Company in 1991, served as Controller from 1999 - 2004, and has served as Vice President Accounting since 2004.

**PART II**

**ITEM 5.** *Market for the Registrant s Common Equity; 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 |
|---|---|---|
| **2006** | | |
| 1st Quarter | $ 46.14 | $ 60.42 |
| 2nd Quarter | $ 39.35 | $ 54.12 |
| 3rd Quarter | $ 38.01 | $ 48.76 |
| 4th Quarter | $ 38.35 | $ 54.34 |
| **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 |

As of February 1, 2007, there were 1,946 holders of record of the Company s Common Stock.

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 and the Company paid four quarterly dividends of that amount during 2006. 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 ), 7.875% Senior Subordinated Notes due 2013 (the 2013 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, 2006.

During the fourth quarter of the year ended December 31, 2006, no equity securities of the Company of any class registered by the Company pursuant to Section 12 of the Securities Exchange Act of 1934 were purchased by or on behalf of the Company or any affiliated purchaser of the Company, as defined in Rule 10b-18(a)(3) under the Securities Exchange Act.

*Performance Graph.* Set forth below is a line graph comparing the change in the cumulative total shareholder return on the Company s Common Stock against the cumulative total return of (i) the Standard & Poor s 500 Stock Index and (ii) the Standard & Poor s Oil and Gas Exploration and Production Index, each for the period of five fiscal years commencing December 31, 2001 and ended December 31, 2006 and each of which assumes an initial value of $100 and reinvestment of all dividends.

**Comparison of Five-Year Cumulative Total Shareholder Return**

Note: The stock price performance for the Company s Common Stock is not necessarily indicative of future performance.

The performance graph above is being furnished solely to accompany this annual report on Form 10-K pursuant to Item 201(e) of Regulation S-K, and is not being filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not being incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

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

In the following table, the Company s financial, production and other data for 2005 and 2006 reflect the Company s acquisition of Northrock Resources ( Northrock ) from and on September 27, 2005. The Company s financial, production, and other data for 2006 also reflect the acquisition of Latigo Petroleum, Inc. ( Latigo ) from and on May 2, 2006. The Company s results for periods presented prior to 2006 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, | | | | |
|---|---|---|---|---|---|
| | 2006 | 2005 | 2004 | 2003 | 2002 |
| | (Expressed in millions, except per share and production data) | | | | |
| **Financial Data** | | | | | |
| Revenues: | | | | | |
| Crude oil and condensate | $ 653.5 | $ 468.3 | $ 417.1 | $ 426.4 | $ 282.0 |
| Natural gas | 642.8 | 695.4 | 512.6 | 397.3 | 231.3 |
| Natural gas liquids | 79.1 | 52.5 | 43.4 | 32.4 | 24.4 |
| Oil and gas revenues | 1,375.4 | 1,216.2 | 973.1 | 856.1 | 537.7 |
| Other | 369.6 (a) | 9.5 | 3.5 | 2.4 | 4.4 |
| Total | $ 1,745.0 | $ 1,225.7 | $ 976.6 | $ 858.5 | $ 542.1 |
| Income from continuing operations before cumulative effect of change in accounting principle | $ 446.2 | $ 290.1 | $ 249.0 | $ 235.2 | $ 68.6 |
| Income from discontinued operations, net of tax | | 460.6 (b) | 12.7 | 59.9 | 38.4 |
| Cumulative effect of change in accounting principle | | | | (4.2 )(c) | |
| Net income | $ 446.2 | $ 750.7 | $ 261.7 | $ 290.9 | $ 107.0 |
| Per share data: | | | | | |
| Basic income from operations before cumulative effect of change in accounting principle | | | | | |
| From continuing operations | $ 7.74 | $ 4.80 | $ 3.90 | $ 3.76 | $ 1.18 |
| From discontinued operations | | 7.63 | 0.20 | 0.96 | 0.67 |
| Basic income from operations before cumulative effect of change in accounting principle | $ 7.74 | $ 12.43 | $ 4.10 | $ 4.72 | $ 1.85 |
| Diluted income from operations before cumulative effect of change in accounting principle | | | | | |
| From continuing operations | $ 7.68 | $ 4.76 | $ 3.87 | $ 3.67 | $ 1.16 |
| From discontinued operations | | 7.56 | 0.19 | 0.93 | 0.61 |
| Diluted income from operations before cumulative effect of change in accounting principle | $ 7.68 | $ 12.32 | $ 4.06 | $ 4.60 | $ 1.77 |
| Cash dividends on common stock | $ 0.30 | $ 0.25 | $ 0.2125 | $ 0.20 | $ 0.12 |
| Price range of common stock: | | | | | |
| High | $ 60.42 | $ 59.69 | $ 51.34 | $ 49.50 | $ 39.28 |
| Low | $ 38.01 | $ 41.59 | $ 39.25 | $ 34.29 | $ 23.00 |
| Weighted average number of common shares outstanding | | | | | |
| Basic | 57.6 | 60.4 | 63.8 | 62.5 | 57.9 |
| Diluted | 58.1 | 60.9 | 64.4 | 64.6 | 64.3 |
| Long-term debt at year end | $ 2,319.7 | $ 1,643.5 | $ 755.0 | $ 487.3 | $ 722.9 |
| Shareholders equity at year end | $ 2,567.4 | $ 2,098.6 | $ 1,727.9 | $ 1,453.7 | $ 1,077.8 |
| Total assets at year end | $ 6,971.1 | $ 5,675.7 | $ 3,481.1 | $ 2,758.7 | $ 2,491.6 |
| **Production (Sales) Data** | | | | | |
| Net daily average production and weighted average price: | | | | | |
| Natural gas (MMcf per day) | 279.6 | 250.2 | 244.3 | 210.4 | 201.3 |
| Price (per Mcf) | $ 6.30 | $ 7.62 | $ 5.73 | $ 5.17 | $ 3.15 |
| Crude oil and condensate (Bbl per day) | 31,180 | 25,734 | 29,530 | 40,173 | 30,971 |
| Price (per Bbl) | $ 57.42 | $ 49.85 | $ 38.59 | $ 29.08 | $ 24.95 |
| Natural gas liquids (Bbl per day) | 5,744 | 4,162 | 4,220 | 4,109 | 4,480 |
| Price (per Bbl) | $ 37.71 | $ 34.56 | $ 28.09 | $ 21.59 | $ 14.94 |

| | For the Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2006 | 2005 | 2004 | 2003 | 2002 |
| | (Expressed in millions) | | | | |
| **Capital Expenditures (including interest capitalized)** | | | | | |
| Oil and gas: | | | | | |
| Domestic Onshore | | | | | |
| Exploration | $ 210.2 | $ 117.1 | $ 29.0 | $ 26.2 | $ 14.5 |
| Development | 371.2 | 143.3 | 159.5 | 118.0 | 117.2 |
| Purchase of properties | 1,046.2 | 46.0 | 583.8 | 177.7 | |
| Domestic Offshore | | | | | |
| Exploration | 12.1 | 63.8 | 54.3 | 28.1 | 33.6 |
| Development | 35.1 | 20.9 | 74.0 | 23.9 | 100.7 |
| Purchase of properties | | | 24.7 | | |
| Canada | | | | | |
| Exploration | 75.1 | 9.1 | | | |
| Development | 230.9 | 55.8 | | | |
| Purchase of properties | 36.8 | 2,616.9 | | | |
| Other international | | | | | |
| Exploration | 0.1 | | 5.6 | 0.1 | |
| Development | | 0.1 | | | |
| Total oil and gas | 2,017.7 | 3,073.0 | 930.9 | 374.0 | 266.0 |
| Other | 4.7 | 6.0 | 6.2 | 2.5 | 3.3 |
| Total | $ 2,022.4 | $ 3,079.0 | $ 937.1 | $ 376.5 | $ 269.3 |

(a) Includes a pre-tax gain of $302.7 million from the sale of an undivided 50% of the Company s Gulf of Mexico oil and gas leasehold interests and related pipelines and equipment to an affiliate of Mitsui & Co., Ltd.

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

(c) 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 Item 1A 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 for all periods presented prior to 2006. See Note 11 Discontinued Operations to the Consolidated Financial Statements in Item 8 Financial Statements and Supplementary Data . Except where noted, the following discussion relates to the Company s continuing activities only. However, the assets comprising the Company s continuing operations have changed substantially during the periods presented, which affects comparability between periods. The Company acquired Northrock on September 27, 2005 and Latigo on May 2, 2006, and disposed of 50% of its interests in its Gulf of Mexico properties on May 31, 2006. For summary pro forma results of operations from the Company s continuing operations as if the Northrock and Latigo acquisitions had occurred on January 1, 2004, please refer to Note 5 Acquisitions to the Consolidated Financial Statements in Item 8 Financial Statements and Supplementary Data .

**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 2006 marked the fifteenth 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 and Vietnam. 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, 2006, approximately 94% 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 12 years.

At the end of 2006, proven reserves reached 2,213 Bcfe and production for the year averaged more than 83,500 BOE per day (501,000 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.

Oil and gas capital and exploration cash expenditures for 2006 were approximately $1.7 billion. Exploration and development operations were allocated approximately $943 million, and approximately $787 million was spent on selective acquisitions in the Company s core areas of operations. For 2006 the

Company drilled 488 wells with 432 successfully completed, an 89% success rate. During 2006, approximately 497 Bcfe of proven reserves were added to the Company s reserves ledger.

*2006 Results*

Total revenue for 2006 was $1,745.0 million and net income totaled $446.2 million, or $7.74 per share. Cash flow from operations totaled $651.9 million. As of December 31, 2006, long-term debt was $2,319.7 million, increasing from December 31, 2005 by $676.2 million. The Company s debt to total capitalization ratio, an indicator of a company s financial strength, was 47% at December 31, 2006 and cash and cash equivalents decreased from $57.7 million at December 31, 2005 to approximately $22.7 million at December 31, 2006. The increase in debt and the decrease in cash are both due primarily to the closing of the Latigo acquisition and increased capital expenditures.

*Strategic Alternatives Process*

On February 15, 2007, the Company confirmed that its Board of Directors previously initiated the exploration of a range of strategic alternatives to enhance shareholder value and is continuing to do so, including the possible sale or merger of Pogo, the sale of its Canadian, Gulf Coast, Gulf of Mexico or other significant assets, and changes to the Company s business plan. Pogo has retained Goldman, Sachs & Co. and TD Securities Inc. as financial advisors for the process.

*Acquisition of Latigo Petroleum Inc.*

On May 2, 2006, the Company completed the acquisition of Latigo Petroleum, Inc. ( Latigo ), a privately held exploration and production company for approximately $764.9 million. The purchase price was funded using cash on hand and debt financing. As of December 31, 2006, Latigo s estimated proved reserves were approximately 328 Bcfe. Latigo s operations are concentrated in the Permian Basin and Panhandle of Texas.

*Sale of 50% of Gulf of Mexico Interests*

On May 31, 2006, the Company closed the sale of an undivided 50 percent interest of each of its Gulf of Mexico oil and gas leasehold interests and related pipelines and equipment to an affiliate of Mitsui & Co., Ltd., for approximately $448.8 million. The proceeds were used to repay a portion of the debt used to finance the Latigo acquisition. As of December 31, 2005, the interests sold were attributed approximately 143 Bcfe of net estimated proven oil and gas reserves. The Company recognized a pre-tax gain of $302.7 million related to the sale in the second quarter of 2006.

*Issuance of Senior Subordinated Notes*

On June 6, 2006, the Company issued and sold $450 million aggregate principal amount of 7.875% Senior Subordinated Notes due 2013 (the 2013 Notes ). Net proceeds were used to reduce outstanding debt under the Company s credit facility.

*Recognition of Income Tax Benefit*

During 2006, the Company s consolidated effective tax rate was 10.6%, down from 36.7% in 2005. This decrease relates to the enactment of a reduction of the Alberta and Saskatchewan provincial tax rates, in addition to a reduction in the statutory Canadian federal income tax rate, which generated a one-time deferred tax benefit of approximately $112 million.

*Commodity Derivatives*

Although the Company s collars are effective as economic hedges, the sale of 50% of the Company s Gulf of Mexico interests on May 31, 2006 and 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. The Company recognized a $7.3 million non-cash gain related to these contracts in 2006.

*2007 Capital Budget*

The Company has established a $720 million exploration and development budget (excluding property acquisitions) for 2007. The Company expects to spend approximately $199 million on exploration and $521 million on development activities. The capital budget calls for the drilling of approximately 370 wells during 2007, including wells in the United States, Canada, and New Zealand.

*2007 Production Outlook Update*

The Company provided 2007 production guidance in its Form 8-K dated February 15, 2007. 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. 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 2006 were $1,375.4 million, an increase of approximately 13% from oil and gas revenues of $1,216.2 million for 2005, which were an increase of approximately 25% from oil and gas revenues of $973.1 million for 2004. The following table reflects an analysis of variances in the Company s oil and gas revenues (expressed in millions) between years:

| | 2006 Compared to 2005 | 2005 Compared to 2004 |
|---|---|---|
| Increase (decrease) in oil and gas revenues resulting from variances in: | | |
| **Natural gas** | | |
| Price | $ (120.2 ) | $ 168.5 |
| Production | 67.6 | 14.4 |
| | (52.6 ) | 182.9 |
| **Crude oil and condensate** | | |
| Price | 71.1 | 121.8 |
| Production | 114.1 | (70.6 ) |
| | 185.2 | 51.2 |
| **Natural gas liquids ( NGL )** | 26.5 | 9.1 |
| Increase in oil and gas revenues | $ 159.1 | $ 243.2 |

The increase in the Company s oil and gas revenues in 2006, compared to 2005, is related to increases in both the average price that the Company received for its oil and condensate production volumes and an increase in the Company s hydrocarbon production volumes, partially offset by a decrease in the average price that the Company received for its natural gas production volumes. 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 oil and gas revenues for 2006, compared to 2005 and for 2005 compared to 2004, was also the result of an increase in NGL production volumes and in the average price that the Company received for those volumes.

| | 2006 | 2005 | % Change 2005 to 2006 | 2004 | % Change 2004 to 2005 |
|---|---|---|---|---|---|
| **Comparison of Increases (Decreases) in:** | | | | | |
| **Natural Gas** | | | | | |
| Average prices | | | | | |
| United States(a) | **$ 6.19** | $ 7.46 | **(17 )%** | $ 5.73 | **30 %** |
| Canada | **$ 6.50** | $ 10.96 | **(41 )%** | $ | **N/A** |
| Company-wide average price | **$ 6.30** | $ 7.62 | **(17 )%** | $ 5.73 | **33 %** |
| Average daily production volumes (MMcf per day): | | | | | |
| United States | **201.5** | 231.6 | **(13 )%** | 244.3 | **(5 )%** |
| Canada(c) | **78.1** | 18.6 | **N/A** | | **N/A** |
| Company-wide average daily production | **279.6** | 250.2 | **12 %** | 244.3 | **2 %** |
| **Crude Oil and Condensate** | | | | | |
| Average prices | | | | | |
| United States(b) | **$ 62.73** | $ 50.90 | **23 %** | $ 38.59 | **32 %** |
| Canada | **$ 50.40** | $ 44.29 | **14 %** | $ | **N/A** |
| Company-wide average price | **$ 57.42** | $ 49.85 | **15 %** | $ 38.59 | **29 %** |
| Average daily production volumes (Bbls per day): | | | | | |
| United States | **17,717** | 22,337 | **(21 )%** | 29,530 | **(24 )%** |
| Canada(c) | **13,463** | 3,397 | **N/A** | | **N/A** |
| Company-wide average daily production | **31,180** | 25,734 | **21 %** | 29,530 | **(13 )%** |
| **Total Liquid Hydrocarbons** | | | | | |
| Average daily production volumes (Bbls per day) | **36,924** | 29,896 | **24 %** | 33,750 | **(11 )%** |

(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 $0.03 and $0.11 during 2006 and 2005, 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 $0.01 and $0.20 during 2006 and 2005, 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. The average daily production volumes for Canada in 2005 are presented on an annualized basis, calculated by dividing the production for the 96 day period that the Company owned Northrock by 365 days. This presentation is intended to reflect the impact of the acquisition and is not considered meaningful for comparison purposes. On a non-annualized basis, the average daily production for the 96 day period was 70.7 MMcf of natural gas and 12,921 bbls of crude oil and condensate.

*Natural Gas Production.* The increase in the Company s natural gas production during 2006, compared to 2005, was primarily due to the acquisitions of Northrock on September 27, 2005 (which only made a partial year contribution to 2005 production) and Latigo on May 2, 2006. The increased natural gas production from both of the acquisitions was partially offset by decreased production in the Company s

Gulf of Mexico region resulting from the sale of 50% of the Company s interest in its Gulf of Mexico properties on May 31, 2006, natural production declines, and the curtailment of production in 2006 due to the infrastructure damage caused by Hurricanes Katrina and Rita in the third quarter of 2005. 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.

*Crude Oil and Condensate Production.* The increase in the Company s crude oil and condensate production during 2006, compared to 2005, was primarily due to the Northrock and Latigo acquisitions, partially offset by the Gulf of Mexico sale, natural production declines, and curtailment of production resulting from hurricanes. 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.

*NGL Revenues.* 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 2006, compared with 2005, related to an increase in the average price that the Company received for its NGL production to $37.71 in 2006 from $34.56 in 2005 and an increase in NGL production volumes. 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 and an increase in NGL production volumes.

*Gain (loss) on Sale of Assets*

Gain (loss) on the sale of assets is derived from the sale of oil and gas properties and other assets, including tubular stock and vehicles. On May 31, 2006, the Company sold an undivided 50 percent interest in each and all of its Gulf of Mexico oil and gas leasehold interests and related pipelines and equipment to an affiliate of Mitsui & Co., Ltd., for approximately $448.8 million, after purchase price adjustments. The sale resulted in a pre-tax gain of $302.7 million. This gain, along with $2 million of pre-tax gains on sales of other properties and assets, has been reflected in the caption Gain (loss) on sale of properties in the Company s results of operations.

*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 2006, compared to 2005 and 2004, is related primarily to $59.1 million of natural gas inventory sales from the Company s Canadian operations for 2006. Only $5.6 million of these gas inventory sales were made in 2005 in the period subsequent to the Company s acquisition of Northrock on September 27, 2005. Gas inventory sales are related solely to the Company s Canadian operations and were therefore not present in 2004.

*Costs and Expenses*

| Comparison of Increases (Decreases) in: | 2006 | 2005 | % Change 2005 to 2006 | 2004 | % Change 2004 to 2005 |
|---|---|---|---|---|---|
| | (expressed in millions, except DD&A rate) | | | | |
| **Lease Operating Expenses** | **$ 264.8** | **$ 153.7** | **72 %** | $ 100.5 | **53 %** |
| **General and Administrative Expenses** | **$ 129.5** | **$ 87.3** | **48 %** | $ 62.1 | **41 %** |
| **Exploration Expenses** | **$ 31.8** | **$ 26.5** | **20 %** | $ 21.7 | **22 %** |
| **Dry Hole and Impairment Expenses** | **$ 106.6** | **$ 87.2** | **22 %** | $ 61.6 | **42 %** |
| **Depreciation, Depletion and** | | | | | |
| **Amortization (DD&A) Expenses** | **$ 484.6** | **$ 312.2** | **55 %** | $ 251.9 | **24 %** |
| DD&A rate | **$ 2.65** | **$ 1.99** | **33 %** | $ 1.54 | **29 %** |
| Mcfe produced | **182.9** | **156.8** | **17 %** | 163.5 | **(4 )%** |
| **Production and Other Taxes** | **$ 78.4** | **$ 59.5** | **32 %** | $ 44.1 | **35 %** |
| **Other** | **$ 87.0** | **$ (9.1 )** | **(1052 )%** | $ 8.4 | **(209 )%** |
| **Interest** | | | | | |
| Charges | **$ (148.1 )** | **$ (68.7 )** | **116 %** | $ (29.3 ) | **134 %** |
| Interest Income | **$ 1.8** | **$ 8.3** | **(78 )%** | $ 0.5 | **1488 %** |
| Capitalized Interest Expense | **$ 77.7** | **$ 23.5** | **231 %** | $ 14.2 | **65 %** |
| **Commodity Derivative Income (Expense)** | **$ 7.3** | **$ (13.6 )** | **(154 )%** | $ | **N/A** |
| **Loss on debt extinguishment** | **$** | **$** | **N/A** | $ (13.8 ) | **(100 )%** |
| **Income Tax Expense** | **$ (53.1 )** | **$ (167.9 )** | **(68 )%** | $ (148.9 ) | **13 %** |

*Lease Operating Expenses*

The increase in lease operating expenses for 2006, compared to 2005, is primarily related the inclusion of a full year of expenses for Northrock, which was acquired in late September 2005; the acquisition of Latigo in May 2006; higher costs being charged by service companies in 2006 relative to 2005; and, to a lesser extent, costs associated with hurricane related repairs. These higher expenses were only partially offset by the reduction in lease operating expense related to the sale of 50% of the Company s Gulf of Mexico offshore interests on May 31, 2006. 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 service companies in 2005 relative to 2004. The Company currently expects lease operating expenses to increase in future periods with the addition of Latigo related expenses for an entire reporting period. This increase in 2007 should be partially mitigated by the property sales discussed in Gain (loss) on sale of assets above.

On a per unit of production basis, the Company s total lease operating expenses were $1.45 per Mcfe for 2006, $0.98 per Mcfe for 2005 and $0.61 per Mcfe for 2004. The increased unit costs in 2006 and 2005 were primarily related to the increased expenses discussed above, compounded by natural production declines and reduced offshore hydrocarbon production related to hurricane damage.

*General and Administrative Expenses*

The increase in general and administrative expenses for 2006, compared with 2005, and 2005 compared with 2004, is primarily related to increases in the size of the Company s workforce due to acquisitions, increased benefit expenses and increases in compensation. The Company currently expects general and administrative expenses to increase in future periods with the addition of Latigo related expenses for the entire reporting period and the establishment of a Change of Control Retention Program to provide retention incentive for eligible employees during 2007. See Note 7 Severance and Retention Incentive Program to the Consolidated Financial Statements in Item 8 Financial Statements and Supplementary Data for additional information on the Change of Control Retention Program.

On a per unit of production basis, the Company s general and administrative expenses were $0.71 per Mcfe in 2006, $0.56 per Mcfe in 2005 and $0.38 per Mcfe in 2004. The increased unit costs resulted from the increases in expenses discussed above.

*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 2006, compared to 2005, resulted primarily from an increase in seismic activity in the Company s Canadian and Vietnam operations and an increase in delay rentals in the Company s Canadian operation and Gulf Coast region, partially offset by decreased seismic activity in the New Zealand operation and a decrease in exploration activity in the Gulf of Mexico due to the sale of 50% of the Company s interests. 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.

*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 2006, the Company drilled 25 gross unsuccessful exploratory wells (20.3 net to the Company s interest) for a total cost of approximately $60.9 million; in 2005 the Company drilled 9 unsuccessful exploratory wells (7.1 net to the Company s interest) for a total cost of $67.1 million; and 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.

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 $45.7 million during 2006, approximately $20.1 million during 2005 and $21.4 million during 2004.

*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 for its onshore oil and gas activities on the basis of a reasonable aggregation of properties with a common geologic structural feature or stratigraphic condition. The Company generally creates cost centers on a field-by-field basis for oil and gas activities in offshore areas.

The increase in the Company s DD&A expense for 2006, compared to 2005, 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 offshore fields and legacy onshore fields) 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 production from the Northrock and Latigo acquisitions). The Company currently expects its average DD&A rate to increase during 2007, as the effects of the higher rate per Mcf Latigo properties and the sale of the lower rate per Mcf Gulf of Mexico properties have a greater impact on the Company s overall production profile.

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 through corporate acquisitions).

*Production and Other Taxes*

The increase in production and other taxes for 2006, compared to 2005, and for 2005, compared to 2004, is primarily related to increased severance taxes due to higher onshore production volumes and higher crude and condensate prices, partially offset by lower natural gas prices, and higher ad valorem taxes due to acquisitions.

*Other*

Other expense includes the Company s cost to move its products to market (transportation costs), natural gas purchase costs, accretion expense related to Company asset retirement obligations under generally accepted accounting principles, 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 Other and the changes between periods (expressed in millions):

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| Gas inventory purchases | $ 56.0 | $ 4.5 | $ |
| Transportation costs | 18.9 | 14.6 | 13.3 |
| Accretion expense | 12.2 | 8.0 | 4.8 |
| Business interruption insurance | (9.2 ) | (40.7 ) | (11.1 ) |
| Other | 9.1 | 4.5 | 1.4 |
| Total | $ 87.0 | $ (9.1 ) | $ 8.4 |

Gas inventory purchases increased in 2006 compared to 2005 due to the inclusion of a full year of purchases related to Northrock. Gas inventory purchases are related solely to the Company s Canadian operations and were therefore not present in 2004. Transportation costs increased in 2006 compared to 2005 due to the Latigo acquisition and the inclusion of a full year of costs related to Northrock. Accretion expense increased in 2006 compared to 2005 due to increased estimates of future liabilities due to rising service costs and the inclusion of a full year of expense related to Northrock. 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. The business interruption insurance relates to claims from the shut-in of a significant portion of the Company s Gulf of Mexico production during 2006, 2005, and the fourth quarter of 2004 as a result of the infrastructure damage caused by Hurricanes Ivan, Katrina and Rita.

*Interest*

*Interest Charges.* The increase in the Company s interest charges for 2006, compared to 2005, was due to an increase in the average amount of the Company s outstanding debt during 2006 (incurred primarily to fund the purchase of Northrock and Latigo) and, to a lesser extent, an increase in the average interest rate on the Company s revolving credit facility from 5.84% in 2005 to 6.85% in 2006. 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 and, to a lesser extent, an increase in the average interest rate on the Company s revolving credit facility from 3.67% in 2004 to 5.84% in 2005. The Company incurred approximately $763 million in additional debt in connection with the Latigo acquisition in May 2006 and $690 million in additional debt in connection with the Northrock acquisition in September 2005, which had a significant impact on the Company s 2006 and 2005 interest expense. 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 decrease in the Company s interest income for 2006, compared to 2005 resulted from a decrease in the average amount of cash and cash equivalents temporarily invested. The cash and cash equivalents invested during 2005 increased from 2004 primarily due to the 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 2006, compared to 2005, and for 2005, compared to 2004, resulted from an increase in the average amount of capital expenditures subject to interest capitalization, as well as the increase in interest charges discussed above. The average amount of capital expenditures subject to interest capitalization was $1.1 billion, $358 million, and $210 million for the years 2006, 2005, and 2004, respectively. In the fourth quarter of 2006, the Company changed the classification of interest capitalized in the Statement of Cash Flows from an operating cash outflow to an investing cash outflow. The Company will reflect this new classification in all future reporting periods.

*Commodity Derivative Income (Expense)*

Commodity derivative income (expense) for 2005 and 2006 represents gains or 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 sale of 50% of the Company s Gulf of Mexico interests on May 31, 2006, and the shut-in forecasted 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 Company recorded realized and unrealized gains (losses) related to these contracts of $7.3 million and ($13.6) million for the periods ended December 31, 2006, and 2005, respectively. No such expense was incurred during 2004, 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.

*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 decrease in the Company s income tax expense for 2006, compared to 2005, primarily resulted from favorable tax benefits in Canada during 2006, and 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 19% (phased in through 2010), and the phase-in of a deduction in Canada for Crown royalties. The increase in the Company s tax expense for 2005, compared to 2004, resulted primarily from increased pre-tax income. The Company s consolidated effective tax rate for 2006, 2005 and 2004 was 10.6%, 36.7%, and 37.4%, respectively.

*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 millions):

***Operating Results Data***

| | Year Ended December 31, 2005 | 2004 |
|---|---|---|
| Revenues | $ 252.8 | $ 335.3 |
| Costs and expenses | (126.5 ) | (237.1 ) |
| Other income | 5.0 | 0.3 |
| Income before income taxes | 131.3 | 98.5 |
| Income taxes | (78.5 ) | (85.8 ) |
| Income before gain from discontinued operations, net of tax | 52.8 | 12.7 |
| Gain on sale, net of tax of $9.7 million | 407.8 | |
| Income from discontinued operations, net of tax | $ 460.6 | $ 12.7 |

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 Company recognized no tax benefit for its costs in Hungary, resulting in a high effective tax rate for each of the periods presented.

**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 2006 was $651.9 million. This compares to cash flow from operating activities of $845.5 million in 2005 and $738.7 million in 2004. The resulting changes are attributable to the reasons described under Results of Operations above. Cash flows used in investing activities for 2006 were $1,332.3 million, which included the approximately $764.9 million Latigo transaction that was funded using available cash on hand, the net proceeds from the Company s offering of the 2013 Notes, and additional borrowings under the revolving credit facility. Cash flows provided by financing activities were $644.7 million for 2006. During 2006, the Company issued $450 million principal amount of 2013 Notes (see description below) and borrowed cash of $226 million (net of repayments) under its revolving credit facility and money market lines. During 2006, the Company also paid for the repurchase of $7.7 million of its common stock and paid $17.5 million of common stock dividends. As of December 31, 2006, the Company had cash and cash equivalents of $22.7 million and long-term debt obligations of $2.3 billion (excluding debt discount) with no repayment obligations until 2009. The

Company may determine to repurchase outstanding debt in the future, including in open market transactions, privately negotiated transactions or otherwise, depending on market conditions, liquidity requirements, contractual restrictions and other factors.

Effective October 20, 2006, the Company s lenders redetermined the borrowing base under its $1 billion revolving credit facility at $1.5 billion. As of February 21, 2007, the Company had an outstanding balance of $823 million under its facility. As such, the available borrowing capacity under the facility was $177 million.

*Corporate Acquisitions*

On May 2, 2006, the Company completed the acquisition of Latigo Petroleum, Inc. ( Latigo ), a privately held corporation for approximately $764.9 million in cash, including transaction costs. The purchase price was funded using cash on hand and debt financing. Latigo s operations are concentrated in west Texas and the Texas Panhandle with key exploration plays in the Texas Panhandle. The Company acquired Latigo primarily to strengthen its position in domestic exploration and development properties.

In addition to the Latigo acquisition, the Company also completed the corporate acquisition of a Canadian company on February 21, 2006 for cash consideration totaling approximately $18.6 million.

*2013 Notes*

On June 6, 2006, the Company issued $450 million principal amount of 7.875% senior subordinated notes due 2013. The proceeds from the sale of the 2013 Notes were used to pay down obligations under the Company s bank revolving credit agreement. The 2013 Notes bear interest at a rate of 7.875%, payable semi-annually in arrears on May 1 and November 1 of each year. The 2013 Notes are general unsecured senior subordinated obligations of the Company, and are subordinated in right of payment to the Company s senior indebtedness, which currently includes the Company s obligations under the bank revolving credit agreement and LIBOR rate advances. The Company, at its option, may redeem the 2013 Notes in whole or in part, at any time on or after May 1, 2010, at a redemption price of 103.938% of their principal amount and decreasing percentages thereafter. The Company may also redeem a portion of the 2013 Notes prior to May 1, 2009 with proceeds from equity offerings, and some or all of the Notes prior to May 1, 2010, in each case by paying specified premiums. The indenture governing the 2013 Notes also imposes certain covenants on the Company, including covenants limiting: incurrence of indebtedness, including senior indebtedness; payments of dividends, stock repurchases, and redemption of subordinated debt; the sales of assets or subsidiary capital stock; transactions with affiliates; liens; agreements restricting dividends and distributions by subsidiaries; and mergers or consolidations.

In the event of a change of control , as defined in the 2013 Note agreement, the repayment terms of the 2013 Notes could be accelerated. For additional discussion, see Change of Control below.

*LIBOR Rate Advances*

Under separate Promissory Note Agreements with various lenders, LIBOR rate advances are made available to the Company on an uncommitted basis up to $100 million. 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, 2013 Notes, 2015 Notes and 2017 Notes may restrict all or a portion of the amounts that may be borrowed under the Promissory Note Agreements. The Promissory Note Agreements permit either party to terminate the letter agreements at any time upon three-business days notice. As of February 21, 2007 there was $100 million outstanding under these agreements.

*Change of Control*

On February 23, 2007, a shareholder that beneficially owns approximately 7.9% of the Company s stock, formally provided notice to the Company of its intention to conduct a proxy contest at the Company s 2007 Annual Meeting that would, if successful, result in a change in a majority of the Board of Directors by (i) nominating three persons in opposition to the Board s nominees and (ii) proposing amendments to the Company s bylaws to expand the Board and elect three additional nominees. Directors are elected by a plurality of vote of the shareholders, and amendments to the Company s bylaws must be approved by a majority of the shares outstanding. If there is a change in a majority of the Board of Directors not approved by a vote of two-thirds of the incumbent directors, the indentures governing the Company s senior subordinated notes require the Company to offer to repurchase all outstanding notes at 101% of their principal amount and to repay all outstanding senior debt, including the credit facility, prior to repurchasing the notes (or obtain consent from the lenders allowing for such repurchase). Although such a change in a majority of the Board of Directors would not, by itself, constitute an event of default under the credit facility, failure by the Company to perform its indenture obligations would allow the lenders under the credit facility to accelerate the credit facility debt. During 2007, two series of the Company s notes, representing $800 million in aggregate principal amount, have generally traded below their principal face value, and the other two series, representing $650 million in aggregate principal amount, have generally traded above 101% of their principal amount. The Company cannot predict the actions its noteholders or lenders may take. However, the Company believes that holders whose notes were trading below the repurchase price at the time the rights were triggered would exercise their repurchase rights. Additionally, the Company believes that lenders under its credit facility and holders whose notes were trading above the repurchase price may also exercise their repayment or repurchase rights, as the case may be, to the extent they expect that the holders whose notes were trading below the repurchase price would exercise such rights or for other reasons. The Company does not have sufficient cash available to fund a repurchase of all or a substantial portion of the senior subordinated notes or to repay all or a substantial portion of outstanding debt under the credit facility.

Defaults under, or the acceleration of, the notes or credit facility could significantly and adversely affect the Company s financial position. If the Company were not able to refinance the debt, it could be required to sell substantial assets at distress prices in order to satisfy its obligations or to seek protection under the federal bankruptcy laws. Any refinancing of the Company s existing debt with new debt, if available, would likely involve substantial costs, including the premium to repurchase notes from existing holders and transaction costs associated with obtaining new debt. Such new debt may be on less favorable terms than the Company s existing debt. Refinancing may also negatively impact the Company s strategic alternatives initiative.

A change in the majority of the Board of Directors as a result of the pending proxy contest would also trigger an obligation to make payments under the Company s executive employment agreements (upon termination of employment by the executives during specified periods or in specified circumstances) and under the Company s severance and retention program.

*Future Capital and Other Expenditure Requirements*

The Company s capital and exploration budget for 2007, 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 $720 million. The Company has included 370 gross wells in its 2007 capital and exploration budget, including wells to be drilled in the United States, Canada and New Zealand. As of February 21, 2007, 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.

*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, 2006 are set forth on the following table**:**

| | **Payments due by period (in millions)** | | | | |
|---|---|---|---|---|---|
| | **Total** | **Less than 1 Year** | **1 - 3 Years** | **4 - 5 Years** | **More than 5 Years** |
| Long Term Debt(a) | $ 3,183.8 | $ 106.2 | $ 1,084.4 | $ 400.6 | $ 1,592.6 |
| Operating Lease Obligations(b) | 187.6 | 22.5 | 35.4 | 30.3 | 99.4 |
| Purchase Obligations(c) | 36.1 | 6.5 | 19.7 | 1.1 | 8.8 |
| Asset Retirement Obligations(d) | 1,038.7 | 3.8 | 8.6 | 5.0 | 1,021.3 |
| Other Obligations(e)(f) | 12.2 | 12.2 | | | |
| Total | $ 4,458.4 | $ 151.2 | $ 1,148.1 | $ 437.0 | $ 2,722.1 |

(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 6 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 16 to the Consolidated Financial Statements.

(e) This includes the Company s estimated retention payments to be made as part of the Change of Control Retention Program and payments to be made to the Registered Retirement Savings Plan on behalf of Northrock employees. See Note 7 to the Consolidated Financial Statements.

(f) As of December 31, 2006, the Company has a projected benefit obligation of $12.3 million related to its pension plan. It has been excluded from this table due to the uncertainty of the timing of the funding of the obligation.

See Note 12 to the Consolidated Financial Statements.

*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.

*Production Sharing Contract.* During 2006, the Company, together with a joint venture partner, entered into a Production Sharing Contract with PetroVietnam, the state oil company of Vietnam. Under this agreement, PetroVietnam may exercise the option to hold a participating working interest of up to 20% of any commercial discovery made in the Block 124 area. The Company currently has no production or proved reserves in Vietnam.

*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, 2006, 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 $9.9 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 21, 2007, approximately $2.6 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 21, 2007, 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, 2007. 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. 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 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 21, 2007, there was $823 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 our 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 such properties. 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 a downward reserve revision equivalent to 0.93% of proved reserves during the year ended December 31, 2006, while the years ended December 31, 2005 and 2004 had upward reserve revisions equivalent to 2.75% and 1.05% of proved reserves, respectively. Reserve revisions result from a variety of sources such as changes in well performance related to the efficiency of natural drive mechanisms and the improved understanding of drainage areas. A significant reduction in the 2006 year end price for natural gas resulted in reduced forecasted economic recovery, which more than offset improved performance. For the years ended December 31, 2005 and 2004, increased product prices augmented improved well performance. 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 1% reduction in the Company s proved reserve estimate at December 31, 2006 would result in an annual increase in DD&A expense of approximately $5 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 2006, 2005 and 2004. 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 net 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 or during 2006 due to the sale of 50% of the Company s interests in the Gulf of Mexico) 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 2006, the Company grew through the acquisition of Latigo Petroleum, Inc. 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 net revenues from oil, natural gas and NGL production. 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. We account for future abandonment costs pursuant to

SFAS 143, which 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 $17 million (representing an increase of approximately 10.19% to the Company s December 31, 2006 asset retirement obligation) to increase the Company s DD&A rate by $0.01 per Mcfe for the year ended December 31, 2006.

*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 Other expense and property repair and debris removal 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 12 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 21, 2007, annual inflation in terms of the decrease in the general purchasing power of the dollar is running at a moderate rate. 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 21, 2007.

*Recent Accounting Pronouncements*

On July 13, 2006, the Financial Accounting Standards Board ( FASB ) issued FASB Interpretation No. 48 ( FIN 48 ), Accounting for Uncertainty in Income Taxes an interpretation of FAS 109 . FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, Accounting for Income Taxes. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006 and will be adopted by the Company as of January 1, 2007. The adoption of FIN 48 is not expected to result in an adjustment to the Company s financial statements.

In September, 2006, the FASB issued Statement of Financial Accounting Standards No. 157, Fair Value Measurements (SFAS 157 ). SFAS 157 defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. The Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. The adoption of SFAS 157 is not expected to have a material impact on the Company s financial statements.

**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 21, 2007, 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 millions) and related average interest rates by year of maturity for the Company s debt obligations and their indicated fair market value at December 31, 2006:

| | 2007 | 2008 | 2009 | 2010 | 2011 | Thereafter | Total | Fair Value |
|---|---|---|---|---|---|---|---|---|
| Long-Term Debt: | | | | | | | | |
| Variable Rate | $ | $ | $ 872.0 | $ | $ | $ | $ 872.0 | $ 872.0 |
| Average Interest Rate | | | 6.84 % | | | | 6.84 % | |
| Fixed Rate | $ | $ | $ | $ | $ 200.0 | $ 1,250.0 | $ 1,450.0 | $ 1,429.0 |
| Average Interest Rate | | | | | 8.25 % | 7.18 % | 7.32 % | |

**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 foreign currencies and are therefore subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing and investing transactions. Currently, the Company s greatest exposure to exchange rate fluctuations is for transactions being conducted in Canadian dollars, while the exposures in New Zealand and Vietnam currencies are immaterial at this time. As of February 21, 2007, the Company is not a party to any foreign currency exchange agreement.

**Current Hedging Activity**

As of December 31, 2006, 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 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, 2006 are as follows:

| Contract Period and Type of Contract | Volume | NYMEX Contract Price Floor | Ceiling | Fair Value of Asset/(Liability) (in millions) |
|---|---|---|---|---|
| ***Natural Gas Contracts (MMBtu)(a)*** | | | | |
| Collar Contracts: | | | | |
| January 2007 - December 2007 | 5,475 | $ 6.00 | $ 12.00 | $ 1.6 |
| January 2007 - December 2007 | 1,825 | $ 6.00 | $ 12.15 | $ 0.5 |
| January 2007 - December 2007 | 9,125 | $ 6.00 | $ 12.50 | $ 2.9 |
| January 2007 - December 2007 | 913 | $ 8.00 | $ 13.40 | $ 1.4 |
| January 2007 - December 2007 | 2,738 | $ 8.00 | $ 13.50 | $ 4.2 |
| January 2007 - December 2007 | 913 | $ 8.00 | $ 13.52 | $ 1.4 |
| January 2007 - December 2007 | 913 | $ 8.00 | $ 13.65 | $ 1.4 |
| January 2008 - December 2008 | 1,830 | $ 8.00 | $ 12.05 | $ 1.5 |
| January 2008 - December 2008 | 2,745 | $ 8.00 | $ 12.10 | $ 2.3 |
| January 2008 - December 2008 | 915 | $ 8.00 | $ 12.25 | $ 0.8 |
| ***Crude Oil Contracts (Barrels)*** | | | | |
| Collar Contracts: | | | | |
| January 2007 - December 2007 | 1,460,000 | $ 50.00 | $ 75.00 | $ (2.2 ) |
| January 2007 - December 2007 | 365,000 | $ 50.00 | $ 75.25 | $ (0.6 ) |
| January 2007 - December 2007 | 3,650,000 | $ 50.00 | $ 77.50 | $ (3.9 ) |
| January 2007 - December 2007 | 182,500 | $ 60.00 | $ 82.75 | $ 0.3 |
| January 2007 - December 2007 | 547,500 | $ 60.00 | $ 83.00 | $ 0.9 |
| January 2007 - December 2007 | 182,500 | $ 60.00 | $ 84.00 | $ 0.3 |
| January 2008 - December 2008 | 183,000 | $ 60.00 | $ 80.00 | $ 0.1 |
| January 2008 - December 2008 | 183,000 | $ 60.00 | $ 80.05 | $ 0.1 |
| January 2008 - December 2008 | 183,000 | $ 60.00 | $ 80.10 | $ 0.1 |
| January 2008 - December 2008 | 366,000 | $ 60.00 | $ 80.25 | $ 0.2 |

(a) MMBtu means million British Thermal Units.

Although all of the Company s collars are effective as economic hedges, the sale of 50% of the Company s Gulf of Mexico interests on May 31, 2006 and the shut-in forecasted 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 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 income(expense). As of December 31, 2006, 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 Asset/(Liability) (in millions) |
|---|---|---|---|---|
| ***Natural Gas Contracts (MMBtu)*** | | | | |
| Collar Contracts: | | | | |
| January 2007 - December 2007 | 7,300 | $ 6.00 | $ 12.15 | $ 2.2 |
| January 2007 - December 2007 | 3,650 | $ 6.00 | $ 12.20 | $ 1.1 |

Additional information about the Company s hedging activities can be found in Note 14 Commodity Derivatives and Hedging Activities in this report.

**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 consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 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.

*Internal control over financial reporting*

Also, in our opinion, management s assessment, included in Management's Annual 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, 2006 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, 2006, 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 Latigo Petroleum, Inc. (Latigo) from its assessment of internal control over financial reporting as of December 31, 2006 because Latigo was acquired in a purchase business combination during 2006. We have also excluded Latigo from our audit of internal control over financial reporting. Latigo is a wholly-owned subsidiary of the Company whose total assets and total revenues represent 16% and 5%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2006.

Houston, Texas

March 1, 2007



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**POGO PRODUCING COMPANY & SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF INCOME**

| | Year Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| | (Expressed in millions, except per share amounts) | | |
| **Revenues:** | | | |
| Oil and gas | $ 1,375.4 | $ 1,216.2 | $ 973.1 |
| Gain (loss) on sale of properties | 304.7 | 0.1 | (0.3) |
| Other | 64.9 | 9.4 | 3.8 |
| Total | 1,745.0 | 1,225.7 | 976.6 |
| **Operating Costs and Expenses:** | | | |
| Lease operating | 264.8 | 153.7 | 100.5 |
| General and administrative | 129.5 | 87.3 | 62.1 |
| Exploration | 31.8 | 26.5 | 21.7 |
| Dry hole and impairment | 106.6 | 87.2 | 61.6 |
| Depreciation, depletion and amortization | 484.6 | 312.2 | 251.9 |
| Production and other taxes | 78.4 | 59.5 | 44.1 |
| Other | 87.0 | (9.1) | 8.4 |
| Total | 1,182.7 | 717.3 | 550.3 |
| **Operating Income** | 562.3 | 508.4 | 426.3 |
| **Interest:** | | | |
| Charges | (148.1) | (68.7) | (29.3) |
| Income | 1.8 | 8.3 | 0.5 |
| Capitalized | 77.7 | 23.5 | 14.2 |
| **Commodity Derivative Income (Expense)** | 7.3 | (13.6) | |
| **Loss on debt extinguishment** | | | (13.8) |
| **Foreign Currency Transaction Gain (Loss)** | (1.7) | 0.1 | |
| **Income From Continuing Operations Before Taxes** | 499.3 | 458.0 | 397.9 |
| **Income Tax Expense** | (53.1) | (167.9) | (148.9) |
| **Income From Continuing Operations** | 446.2 | 290.1 | 249.0 |
| **Income from Discontinued Operations, net of tax** | | 460.6 | 12.7 |
| **Net Income** | $ 446.2 | $ 750.7 | $ 261.7 |
| **Earnings per Common Share:** | | | |
| Basic | | | |
| Income from continuing operations | $ 7.74 | $ 4.80 | $ 3.90 |
| Income from discontinued operations | | 7.63 | 0.20 |
| Net income | $ 7.74 | $ 12.43 | $ 4.10 |
| Diluted | | | |
| Income from continuing operations | $ 7.68 | $ 4.76 | $ 3.87 |
| Income from discontinued operations | | 7.56 | 0.19 |
| Net income | $ 7.68 | $ 12.32 | $ 4.06 |
| **Dividends per Common Share** | $ 0.30 | $ 0.25 | $ 0.2125 |

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

**POGO PRODUCING COMPANY & SUBSIDIARIES**

CONSOLIDATED BALANCE SHEETS

| | December 31, 2006 | 2005 |
|---|---|---|
| | (Expressed in millions) | |
| **ASSETS** | | |
| **Current Assets:** | | |
| Cash and cash equivalents | $ 22.7 | $ 57.7 |
| Accounts receivable | 175.8 | 198.8 |
| Other receivables | 47.6 | 19.9 |
| Federal income taxes receivable | 55.8 | 21.7 |
| Deferred income tax | | 12.2 |
| Inventories product | 15.5 | 13.2 |
| Inventories tubulars | 27.7 | 19.1 |
| Commodity derivative contracts | 10.9 | |
| Other | 12.2 | 4.2 |
| Total current assets | 368.2 | 346.8 |
| **Property and Equipment:** | | |
| Oil and gas, on the basis of successful efforts accounting | | |
| Proved properties | 7,369.0 | 6,254.5 |
| Unproved properties | 1,033.2 | 872.2 |
| Other, at cost | 50.7 | 40.5 |
| | 8,452.9 | 7,167.2 |
| Accumulated depreciation, depletion, and amortization | | |
| Oil and gas | (1,863.1 ) | (1,858.3 ) |
| Other | (32.7 ) | (24.5 ) |
| | (1,895.8 ) | (1,882.8 ) |
| Property and equipment, net | 6,557.1 | 5,284.4 |
| **Other Assets:** | | |
| Commodity derivative contracts | 5.0 | |
| Other | 40.8 | 44.5 |
| | 45.8 | 44.5 |
| | $ 6,971.1 | $ 5,675.7 |

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

**POGO PRODUCING COMPANY & SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS**

| | December 31, 2006 | 2005 |
|---|---|---|
| | (Expressed in millions) | |
| **LIABILITIES AND SHAREHOLDERS EQUITY** | | |
| **Current Liabilities:** | | |
| Accounts payable operating activities | $ 181.2 | $ 167.3 |
| Accounts payable investing activities | 159.1 | 137.1 |
| Income taxes payable | 0.8 | 2.0 |
| Accrued interest payable | 26.0 | 20.2 |
| Accrued payroll and related benefits | 5.1 | 3.7 |
| Commodity derivative contracts | | 52.3 |
| Deferred income tax | 7.2 | |
| Other | 22.4 | 12.5 |
| Total current liabilities | 401.8 | 395.1 |
| **Long-Term Debt** | 2,319.7 | 1,643.4 |
| **Deferred Income Tax** | 1,478.0 | 1,316.9 |
| **Asset Retirement Obligation** | 156.3 | 149.4 |
| **Other Liabilities and Deferred Credits** | 47.9 | 72.3 |
| Total liabilities | 4,403.7 | 3,577.1 |
| **Commitments and Contingencies (Note 6)** | | |
| **Shareholders Equity:** | | |
| Preferred stock, $1 par; 4,000,000 shares authorized | | |
| Common stock, $1 par; 200,000,000 shares authorized, and 65,794,206 and 65,275,106 shares issued, respectively | 65.8 | 65.3 |
| Additional capital | 971.4 | 977.9 |
| Retained earnings | 1,892.9 | 1,464.2 |
| Accumulated other comprehensive income (loss) | (1.4 ) | (30.0 ) |
| Deferred compensation | | (17.5 ) |
| Treasury stock (7,365,359 shares, at cost) | (361.3 ) | (361.3 ) |
| Total shareholders equity | 2,567.4 | 2,098.6 |
| | $ 6,971.1 | $ 5,675.7 |

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, 2006 | 2005 | 2004 |
|---|---|---|---|
| | (Expressed in millions) | | |
| **Cash flows from operating activities:** | | | |
| Cash received from customers | $ 1,400.4 | $ 1,238.4 | $ 978.5 |
| Operating, exploration and general and administrative expenses paid | (583.1) | (332.0) | (243.3) |
| Income taxes paid | (139.1) | (197.8) | (159.6) |
| Income taxes received | 3.2 | 0.2 | 0.4 |
| Interest paid | (59.2) | (51.3) | (30.0) |
| Cash received (paid) related to commodity derivative contracts | 2.7 | (11.4) | |
| Business interruption insurance proceeds | 15.5 | 47.1 | |
| Other | 11.5 | 7.6 | (1.7) |
| Net cash provided by continuing operating activities | 651.9 | 700.8 | 544.3 |
| Net cash provided by discontinued operating activities | | 144.7 | 194.4 |
| Net cash provided by operating activities | 651.9 | 845.5 | 738.7 |
| **Cash flows from investing activities:** | | | |
| Capital expenditures | (930.4) | (374.9) | (285.9) |
| Purchase of properties | (88.9) | (131.8) | (189.6) |
| Acquisition of corporations, net of cash acquired of $1.8 million, $32.9 million and $11.9 million, respectively | (779.5) | (1,704.6) | (270.4) |
| Sale of properties and corporations, net of $51.5 million cash on hand in 2005 | 451.4 | 764.1 | 1.5 |
| Purchase of current investments | | (16.8) | (15.0) |
| Sale of current investments | | 122.3 | 15.0 |
| Commodity derivative contracts | (0.4) | (8.6) | |
| Hurricane-related insurance proceeds | 15.5 | 17.9 | |
| Net cash used in continuing investing activities | (1,332.3) | (1,332.4) | (744.4) |
| Net cash used in discontinued investing activities | | (57.8) | (217.3) |
| Net cash used in investing activities | (1,332.3) | (1,390.2) | (961.7) |
| **Cash flows from financing activities:** | | | |
| Borrowings under senior debt agreements | 2,419.0 | 3,865.0 | 2,010.0 |
| Payments under senior debt agreements | (2,193.0) | (3,774.0) | (1,594.0) |
| Proceeds from issuance of new financing | 450.0 | 797.3 | |
| Purchase of Company stock | (7.7) | (351.8) | |
| Payments (to) from discontinued operations | | 138.3 | (25.0) |
| Redemption of debt | | | (157.8) |
| Proceeds from exercise of stock options and realization of tax benefits | 5.2 | 11.2 | 12.0 |
| Payment of cash dividends on common stock | (17.5) | (15.2) | (13.6) |
| Payment of senior debt acquired through corporate purchase | | | (50.0) |
| Payment of financing issue costs and other | (11.3) | (14.9) | (3.8) |
| Net cash provided by continuing financing activities | 644.7 | 655.9 | 177.8 |
| Net cash (used in) provided by discontinued financing activities | | (139.6) | 25.0 |
| Net cash provided by financing activities | 644.7 | 516.3 | 202.8 |
| Effect of exchange rate changes on cash | 0.7 | (0.3) | 2.2 |
| Net decrease in cash and cash equivalents | (35.0) | (28.7) | (18.0) |
| Cash and cash equivalents from continuing operations, beginning of the year | 57.7 | 33.5 | 55.8 |
| Cash and cash equivalents from discontinued operations, beginning of the year | | 52.9 | 48.7 |
| Cash and cash equivalents at the end of the year | $ 22.7 | $ 57.7 | $ 86.5 |

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

**POGO PRODUCING COMPANY AND SUBSIDIARIES**
**CONSOLIDATED STATEMENT OF CASH FLOWS CONTINUED**

| | Year Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| | (Expressed in thousands) | | |
| **Reconciliation of net income to net cash provided by operating activities:** | | | |
| Net income | $ 446.2 | $ 750.7 | $ 261.7 |
| Adjustments to reconcile net income to net cash provided by operating activities | | | |
| Income from discontinued operations, net of tax | | (460.6) | (12.7) |
| (Gains) losses on sales | (304.7) | (0.1) | 0.3 |
| Depreciation, depletion and amortization | 484.6 | 312.2 | 251.9 |
| Dry hole and impairment | 106.6 | 87.2 | 61.6 |
| Other | 6.5 | (6.8) | 8.5 |
| Deferred income taxes | (43.2) | 9.1 | 3.1 |
| Change in assets and liabilities: | | | |
| (Increase) decrease in accounts receivable | 28.7 | (9.9) | (26.7) |
| Increase in federal income taxes receivable | (37.4) | (43.2) | (12.7) |
| Increase in inventory product | (2.3) | (12.1) | |
| (Increase) decrease in other assets | (5.3) | 2.3 | 3.5 |
| Increase (decrease) in accounts payable | (39.0) | 54.3 | 12.7 |
| Increase (decrease) in income taxes payable | (2.3) | 1.9 | (0.7) |
| Increase (decrease) in accrued interest payable | 8.2 | 15.7 | (5.4) |
| Increase in accrued payroll and related benefits | 1.4 | 0.2 | 0.3 |
| Increase (decrease) in other current liabilities | 3.9 | (2.7) | (3.7) |
| Increase in deferred credits | | 2.6 | 2.6 |
| Net cash provided by continuing operating activities | 651.9 | 700.8 | 544.3 |
| Net cash provided by discontinued operating activities | | 144.7 | 194.4 |
| Net cash provided by operating activities | $ 651.9 | $ 845.5 | $ 738.7 |

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

**POGO PRODUCING COMPANY & SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY**
(Expressed in millions)

| | Common Stock(a) | Additional Capital | Retained earnings | Accumulated Other Comprehensive Income (Loss) | Deferred Compensation Restricted Stock | Treasury Stock | Shareholders Equity | Comprehensive Income (Loss) |
|---|---|---|---|---|---|---|---|---|
| **Balance at December 31, 2003** | 63.8 | $ 914.5 | $ 480.6 | $ | $ (3.5) | $ (1.8) | $ 1,453.6 | |
| Net income | | | 261.7 | | | | 261.7 | $ 261.7 |
| Stock option activity and other | 0.5 | 16.8 | | | | | 17.3 | |
| Shares issued as compensation | 0.3 | 12.4 | | | | | 12.7 | |
| Issuance of restricted stock, less amortization of $1.9 million | | | | | (6.4) | | (6.4) | |
| Dividends ($0.2125 per common share) | | | (13.6) | | | | (13.6) | |
| Unrealized gain arising during the year on price hedge contracts | | | | 3.0 | | | 3.0 | |
| Net unrealized gains on price hedge contracts | | | | (0.4) | | | (0.4) | 2.6 |
| Comprehensive income | | | | | | | | $ 264.3 |
| **Balance at December 31, 2004** | 64.6 | $ 943.7 | $ 728.7 | $ 2.6 | $ (9.9) | $ (1.8) | $ 1,727.9 | |
| Net income | | | 750.7 | | | | 750.7 | $ 750.7 |
| Stock option activity and other | 0.4 | 15.9 | | | | | 16.3 | |
| Shares issued as compensation | 0.3 | 18.3 | | | | | 18.6 | |
| Issuance of restricted stock, less amortization of $4.6 million | | | | | (7.6) | | (7.6) | |
| Dividends ($0.25 per common share) | | | (15.2) | | | | (15.2) | |
| Share repurchase | | | | | | (359.5) | (359.5) | |
| Unrealized loss arising during the year on price hedge contracts | | | | (72.2) | | | (72.2) | |
| Reclassification adjustment included in net income | | | | 16.7 | | | 16.7 | |
| Net unrealized gains on price hedge contracts | | | | | | | | (55.5) |
| Foreign currency translation adjustment | | | | 22.9 | | | 22.9 | 22.9 |
| Comprehensive income | | | | | | | | $ 718.1 |
| **Balance at December 31, 2005** | 65.3 | $ 977.9 | $ 1,464.2 | $ (30.0) | $ (17.5) | $ (361.3) | $ 2,098.6 | |
| Net income | | | 446.2 | | | | 446.2 | $ 446.2 |
| Stock option activity and other | 0.1 | 6.1 | | | | | 6.2 | |
| Shares issued as compensation | 0.4 | | | | | | 0.4 | |
| Restricted stock activity | | 15.0 | | | | | 15.0 | |
| Cumulative adjustment FAS 123(R) | | (27.6) | | | 17.5 | | (10.1) | |
| Dividends ($0.30 per common share) | | | (17.5) | | | | (17.5) | |
| Cumulative adjustment FAS 158 | | | | (19.6) | | | (19.6) | |
| Unrealized gain arising during the year on price hedge contracts | | | | 68.1 | | | 68.1 | |
| Reclassification adjustment included in net income | | | | (8.5) | | | (8.5) | |
| Net unrealized gains on price hedge contracts | | | | | | | | 59.6 |
| Foreign currency translation adjustment | | | | (11.4) | | | (11.4) | (11.4) |
| Comprehensive income | | | | | | | | $ 494.4 |
| **Balance at December 31, 2006** | 65.8 | $ 971.4 | $ 1,892.9 | $ (1.4) | $ | $ (361.3) | $ 2,567.4 | |

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

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

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**POGO PRODUCING COMPANY & SUBSIDIARIES**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**(1) Summary of Significant Accounting Policies**

*Nature of Operations*

Pogo Producing Company was incorporated in 1970. Pogo Producing Company and its subsidiaries (the Company ) are engaged in oil and gas exploration, development, production and acquisition activities in 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 and Vietnam.

The Company s results for 2005 and 2004 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, 2006 consisted of approximately 3,653,769 Mcf of natural gas valued at its estimated average cost of $5.66 per Mcf and 78,361 barrels of crude oil and condensate at its estimated average cost of $20.80 per barrel. Natural gas inventory used as storage facility cushion gas to maintain operation pressure 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 future net cash flows. 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 costs related to 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 2006, 2005 and 2004 (amounts expressed in millions):

| | **2006** | **2005** | **2004** |
|---|---|---|---|
| Balance at January 1, | $ 7.1 | $ 11.8 | $ 1.0 |
| Additions to capitalized exploratory well costs pending the determination of proved reserves | 38.5 | 7.1 | 10.8 |
| Reclassifications to proved oil and gas properties | (7.1) | (6.7) | |
| Capitalized exploratory well costs charged to expense | | (5.1) | |
| Balance at December 31, | $ 38.5 | $ 7.1 | $ 11.8 |

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

As of December 31, 2006, the Company has exploratory well costs of $0.3 million related to two Canadian wells that have been capitalized for a period greater than one year.

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, such as geological and geophysical costs and rental payments, 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 for its onshore oil and gas activities on the basis of a reasonable aggregation of properties with a common geologic structural feature or stratigraphic condition. The Company generally creates cost centers on a field-by-field basis for oil and gas activities in offshore areas.

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 Income.

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.

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

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

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 (i.e. ineffectiveness,) if any, must be recognized currently in earnings as Other revenue or expense. 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 income(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 income(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 Other expense and property damage recoveries are recorded as a reduction of Lease operating expense . During the years ended December 31, 2006, 2005, and 2004 the Company recognized $9.2 million, $40.7 million, and $11.1 million, respectively of business interruption insurance recoveries related to deferred production resulting from Hurricanes Ivan, Katrina and Rita. During the same periods, the Company recorded reductions to lease operating expense of $18.5 million, $14.5 million, and $4.9 million, respectively, for property damage recoveries.

*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, or more than $375 million of its common stock. The repurchased shares were accounted for as treasury stock. As of December 31, 2006, the Company had completed the purchase of 7,310,000 shares under this plan at a total cost of $359.5 million.

*Retirement and Post-Retirement Benefits*

As of December 31, 2006, the Company adopted Financial Accounting Statement ( FAS ) No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans , which amends FAS No. 87, Employers Accounting for Pensions , No. 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits , No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions , and No. 132(R), Employers Disclosures About Pensions and Other Postretirement Benefits an amendment of FAS Nos. 87, 88, and 106 . The Statement requires companies to recognize on their 2006 balance sheets the funded status of their pension and other postretirement benefit plans, measured as of the balance sheet date. The Statement also requires that the actuarial gains and losses and the prior service costs and credits that arise during the period be recognized, net of tax, as components of other comprehensive income; these amounts in other comprehensive income will be adjusted as they are subsequently amortized and recognized as net periodic benefit costs. See Note 12 for additional information.

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

*Consolidated Statements 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, accordingly, 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 16 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 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.

*Recent Accounting Pronouncements*

In September, 2006, the FASB issued Statement of Financial Accounting Standards No. 157, Fair Value Measurements (SFAS 157 ). SFAS 157 defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. The Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. The adoption of SFAS 157 is not expected to have a material impact on the Company s financial statements.

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

**(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. Amounts are expressed in millions, except per share amounts.

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| ***Income (numerator):*** | | | |
| Income from continuing operations | $ 446.2 | $ 290.1 | $ 249.0 |
| Income from discontinued operations, net of tax | | 460.6 | 12.7 |
| Net income basic and diluted | $ 446.2 | $ 750.7 | $ 261.7 |
| ***Weighted average shares (denominator):*** | | | |
| Weighted average shares basic | 57.6 | 60.4 | 63.8 |
| Dilution effect of stock options and unvested restricted stock outstanding at end of period | 0.5 | 0.5 | 0.6 |
| Weighted average shares diluted | 58.1 | 60.9 | 64.4 |
| ***Earnings per share:*** | | | |
| Basic: | | | |
| Income from continuing operations | $ 7.74 | $ 4.80 | $ 3.90 |
| Income from discontinued operations | | 7.63 | 0.20 |
| Basic earnings per share | $ 7.74 | $ 12.43 | $ 4.10 |
| Diluted: | | | |
| Income from continuing operations | $ 7.68 | $ 4.76 | $ 3.87 |
| Income from discontinued operations | | 7.56 | 0.19 |
| Diluted earnings per share | $ 7.68 | $ 12.32 | $ 4.06 |
| ***Antidilutive securities;*** | | | |
| Shares assumed not issued from options to purchase common shares as the exercise prices are above the average market price for the period or the effect of the assumed exercise would be antidilutive | 0.02 | | 0.02 |
| Average price | $ 48.93 | $ | $ 49.02 |

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

**(3) Income Taxes**

The components of income from continuing operations before income taxes for each of the three years in the period ended December 31, 2006, are as follows (expressed in millions):

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| United States | $ 424.0 | $ 417.7 | $ 403.8 |
| Foreign | 75.3 | 40.3 | (5.9 ) |
| Income from continuing operations before income taxes | $ 499.3 | $ 458.0 | $ 397.9 |

The components of income tax expense (benefit) for each of the three years in the period ended December 31, 2006, are as follows (expressed in millions):

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Current | | | |
| United States | $ 84.9 | $ 156.9 | $ 145.7 |
| Foreign | 11.4 | 1.9 | 0.1 |
| Deferred | | | |
| United States | 79.5 | (6.1 ) | 3.1 |
| Foreign | (122.7 ) | 15.2 | |
| Income tax expense | $ 53.1 | $ 167.9 | $ 148.9 |

Total income tax expense for each of the three years in the period ended December 31, 2006, 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):

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Federal statutory income tax rate | 35.0 % | 35.0 % | 35.0 % |
| Increases (decreases) resulting from: | | | |
| Canadian income tax | (25.0 ) | | |
| State income taxes, net of federal benefits | 1.3 | 1.6 | 1.5 |
| Other | (0.7 ) | 0.1 | 0.9 |
| | 10.6 % | 36.7 % | 37.4 % |

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

During 2006, the Company s consolidated effective tax rate was 10.6%, down from 36.7% in 2005. This decrease relates to the enactment of a reduction of the Alberta and Saskatchewan provincial tax rates, in addition to a reduction in the statutory Canadian federal income tax rate, which generated a one-time deferred tax benefit of approximately $112 million.

The principal components of the Company s deferred income tax assets and liabilities at December 31, 2006 and 2005 (expressed in millions) are as follows:

| | December 31, 2006 | 2005 |
|---|---|---|
| Deferred tax assets: | | |
| Foreign deferred tax assets and net operating loss carry forwards | $ 2.1 | $ 6.3 |
| Valuation allowance of deferred tax assets and foreign net operating loss | (2.1) | (6.3) |
| Tax basis in excess of book basis for commodity derivative contracts | | 35.2 |
| Tax basis in excess of book basis for deferred compensation and benefit plans | 21.3 | 20.0 |
| Net operating loss carryforwards | 62.3 | 2.4 |
| Other | 4.9 | 4.3 |
| | 88.5 | 61.9 |
| Deferred tax liabilities: | | |
| Book basis in excess of tax basis for oil and gas properties and equipment | (1,567.0) | (1,360.9) |
| Other | (6.7) | (5.7) |
| | (1,573.7) | (1,366.6) |
| Net deferred tax liability | $ (1,485.2) | $ (1,304.7) |

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 for corporations acquired in 2004, 2005, and 2006.

As of December 31, 2006, the Company has a U.S. net operating loss (NOL) carryforward of approximately $178 million that may be used in future years to offset taxable income. The NOL was obtained as part of the acquisition of Latigo Petroleum, Inc. The NOL is subject to certain limitations on future utilization. The Company does not anticipate that these limitations will affect the ultimate utilization of the NOL.

As of December 31, 2006, the Company has a foreign NOL carryforward of approximately $6.4 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 as a result of enacted tax legislation within the applicable foreign jurisdiction and their realization is dependent upon generating sufficient taxable income within the applicable foreign jurisdiction. The $2.1 million valuation allowance at December 31, 2006 was related to exploration expenses the Company incurred in its foreign

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

operations. During 2006, the Company reduced the foreign NOL carryforwards due to the liquidation of several foreign subsidiaries.

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 $220.6 million at December 31, 2006. 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 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.

The Company and its subsidiaries file income tax returns in the U.S. federal and various state and foreign jurisdictions. The Company is no longer subject to U.S. federal, state, or local tax examinations by tax authorities for years prior to 2003. The Company s Canadian subsidiary is no longer subject to examinations by Canadian taxing authorities for years prior to 2002. The Internal Revenue Service ( IRS ) completed the examination of the Company s U.S. income tax returns through 2003 in the fourth quarter of 2005, which resulted in a refund to the Company in 2006 of $1.4 million. The IRS also reviewed the Company s income tax return for 2004 and indicated they do not presently intend to perform an examination of that tax return. Based on the results of the last examination, the Company does not anticipate that any adjustments made to the filings for open years would result in a material change to its financial position.

On January 1, 2007, the Company will adopt the provisions of FASB Interpretation No.48 ( FIN 48 ), Accounting for Uncertainty in Income Taxes. The Company has determined that no uncertain tax positions exist where the Company would be required to make additional tax payments. As a result, the Company has not recorded any additional liabilities for any unrecognized tax benefits as of December 31, 2006, and will not be required to record any on January 1, 2007.

The Company s accounting policy is to recognize penalties and interest related to unrecognized tax benefits as income tax expense. The Company does not have an accrued liability for the payment of penalties and interest at December 31, 2006.

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

**(4) Long-Term Debt**

Long-term debt at December 31, 2006, and 2005, consists of the following (dollars expressed in millions):

| | December 31, 2006 | 2005 |
|---|---|---|
| Senior debt | | |
| Bank revolving credit facility: | | |
| LIBOR based loans, borrowings at December 31, 2006 and 2005 at interest rates of 6.8524% and 5.837%, respectively | $ 797.0 | $ 606.0 |
| LIBOR Rate Advances, borrowings at December 31, 2006 and 2005 at interest rates of 6.6833% and 5.618%, respectively | 75.0 | 40.0 |
| Total senior debt | 872.0 | 646.0 |
| Subordinated debt | | |
| 8.25% Senior subordinated notes, due 2011 | 200.0 | 200.0 |
| 7.875% Senior subordinated notes, due 2013 | 450.0 | |
| 6.625% Senior subordinated notes, due 2015 | 300.0 | 300.0 |
| 6.875% Senior subordinated notes, due 2017 | 500.0 | 500.0 |
| Total subordinated debt | 1,450.0 | 1,000.0 |
| Unamortized discount on 2015 Notes | (2.3 ) | (2.6 ) |
| Long-term debt | $ 2,319.7 | $ 1,643.4 |

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 billion 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, 2006, the borrowing base was $1.5 billion. 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 million for all such increases in commitments of new or existing lenders. Additionally, the Credit Facility 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. All outstanding amounts owed under the Credit Facility become due and payable no later than the final maturity date of December 16, 2009, and are subject to acceleration upon the occurrence of events of default which the Company considers usual and customary for an agreement of this type, including failure to make payments under the credit agreement, non-performance of covenants and obligations continuing beyond any applicable grace period, default in the payment of other indebtedness in excess in principal amount of $25 million 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

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

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 June 6, 2006, the Company issued $450 million principal amount of 7.875% senior subordinated notes due 2013. The proceeds from the sale of the 2013 Notes were used to pay down obligations under the Company s bank revolving credit agreement. The 2013 Notes bear interest at a rate of 7.875%, payable semi-annually in arrears on May 1 and November 1 of each year. The 2013 Notes are general unsecured senior subordinated obligations of the Company, and are subordinated in right of payment to the Company s senior indebtedness, which currently includes the Company s obligations under the bank revolving credit agreement and LIBOR rate advances. The Company, at its option, may redeem the 2013 Notes in whole or in part, at any time on or after May 1, 2010, at a redemption price of 103.938% of their principal amount and decreasing percentages thereafter. The Company may also redeem a portion of the 2013 Notes prior to May 1, 2009 with proceeds from equity offerings, and some or all of the Notes prior to May 1, 2010, in each case by paying specified premiums. The indenture governing the 2013 Notes also imposes certain covenants on the Company, including covenants limiting: incurrence of indebtedness, including senior indebtedness; payments of dividends, stock repurchases, and redemption of subordinated debt; the sales of assets or subsidiary capital stock; transactions with affiliates; liens; agreements restricting dividends and distributions by subsidiaries; and mergers or consolidations.

On September 23, 2005, the Company issued $500 million 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 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

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

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 million 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 Credit Facility 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 million 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 and LIBOR rate advances. 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.

During 2004, the Company redeemed all $150 million 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 $157.8 million (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 $10.9 million in Loss on debt extinguishment during the year ended December 31, 2004.

A change in control in the ownership of the Company, as defined in the subordinated note agreements, could result in the acceleration of debt repayment. See Note 6 Commitments and Contingencies for further discussion.

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

**(5) Acquisitions**

**2006** On May 2, 2006, the Company completed the acquisition of Latigo Petroleum, Inc. ( Latigo ), a privately held corporation for approximately $764.9 million in cash, including transaction costs. The purchase price was funded using cash on hand and debt financing. At the date of purchase, Latigo owned approximately 100,100 net producing acres, plus approximately 304,600 net acres of undeveloped leasehold. Latigo s operations are concentrated in west Texas and the Texas Panhandle with key exploration plays in the Texas Panhandle. The Company acquired Latigo primarily to strengthen its position in domestic exploration and development properties. The following is a calculation and final allocation of purchase price to the acquired assets and liabilities based on their relative fair values:

| | |
|---|---|
| CALCULATION OF PURCHASE PRICE (IN MILLIONS) | |
| Cash paid, including transaction costs | $ 764.9 |
| Plus fair market value of liabilites assumed: | |
| Deferred income taxes | 205.9 |
| Other liabilities | 55.1 |
| Total purchase price for assets acquired | $ 1,025.9 |
| ALLOCATION OF PURCHASE PRICE (IN MILLIONS) | |
| Proved oil and gas properties | $ 846.9 |
| Unproved oil and gas properties | 157.0 |
| Other assets | 22.0 |
| Total | $ 1,025.9 |

In addition to the Latigo acquisition, the Company also completed the corporate acquisition of a Canadian company on February 21, 2006 for cash consideration totaling approximately $18.6 million. The Company recorded the estimated fair value of assets and liabilities that consisted primarily of $26.9 million of oil and gas properties and deferred tax liabilities of $8.0 million. No goodwill was recorded in connection with either of these transactions.

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

**2005** 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 final allocation of purchase price to the acquired assets and liabilities based on their relative fair values:

| | |
|---|---|
| CALCULATION OF PURCHASE PRICE (IN MILLIONS) | |
| Cash paid, including transaction costs | $ 1,737.5 |
| Plus fair market value of liabilites assumed: | |
| Other liabilites | 100.5 |
| Asset retirement obligation | 38.8 |
| Deferred income taxes | 745.6 |
| Total purchase price for assets acquired | $ 2,622.4 |
| ALLOCATION OF PURCHASE PRICE (IN MILLIONS) | |
| Proved oil and gas properties | $ 1,715.8 |
| Unproved oil and gas properties | 787.3 |
| Other assets | 119.3 |
| Total | $ 2,622.4 |

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 $51 million. 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.

**2004** 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, 2006 for the Company s continuing operations as if the acquisitions of Latigo, Northrock, and the corporations had each occurred as of January 1, 2004. The pro forma results are for illustrative purposes only and include, in addition to the pre-acquisition historical results of Latigo, Northrock, and the corporations, adjustments 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 millions 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, 2006 (Unaudited) | 2005 | 2004 |
|---|---|---|---|
| **Pro Forma:** | | | |
| Revenues | $ 1,786.6 | $ 1,621.5 | $ 1,423.1 |
| Net income | 452.9 | 324.9 | 249.6 |
| Earnings per share: | | | |
| Basic | $ 7.86 | $ 5.38 | $ 3.91 |
| Diluted | $ 7.79 | $ 5.33 | $ 3.88 |

## **(6)** Commitments and Contingencies

The Company has commitments for operating leases (primarily for office space) in Houston, Calgary, Midland, Laredo, Tulsa, Ho Chi Minh City, and New Plymouth, and for other equipment (including gas compressors). Rental expense for office space was $6.1 million in 2006, $3.3 million in 2005, and $2.9 million in 2004. Rental expense for other equipment was $10 million in 2006, $6.8 million in 2005 and $5.5 million in 2004.

Future minimum lease payments related to the Company s operating leases at December 31, 2006 are approximately $22.5 million in 2007; $18.4 million in 2008; $17 million in 2009; $15.6 million in 2010; $14.7 million in 2011 and $99.4 million 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.

On February 23, 2007, a shareholder that beneficially owns approximately 7.9% of the Company s stock, formally provided notice to the Company of its intention to conduct a proxy contest at the Company s 2007 Annual Meeting that would, if successful, result in a change in a majority of the Board of Directors by (i) nominating three persons in opposition to the Board s nominees and (ii) proposing amendments to the Company s bylaws to expand the Board and elect three additional nominees. Directors are elected by a plurality of vote of the shareholders, and amendments to the Company s bylaws must be approved by a majority of the shares outstanding. If there is a change in a majority of the Board of Directors not approved by a vote of two-thirds of the incumbent directors, the indentures governing the Company s senior subordinated notes require the Company to offer to repurchase all outstanding notes at 101% of their principal amount and to repay all outstanding senior debt, including the credit facility, prior

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

to repurchasing the notes (or obtain consent from the lenders allowing for such repurchase). Although such a change in a majority of the Board of Directors would not, by itself, constitute an event of default under the credit facility, failure by the Company to perform its indenture obligations would allow the lenders under the credit facility to accelerate the credit facility debt. The Company does not have sufficient cash available to fund a repurchase of all or a substantial portion of the senior subordinated notes or to repay all or a substantial portion of outstanding debt under the credit facility.

Defaults under, or the acceleration of, the notes or credit facility could significantly and adversely affect the Company s financial position. If the Company were not able to refinance the debt, it could be required to sell substantial assets in order to satisfy its obligations or to seek protection under the federal bankruptcy laws. Any refinancing of the Company s existing debt with new debt, if available, would likely involve substantial costs, including the premium to repurchase notes from existing holders and transaction costs associated with obtaining new debt. Such new debt may be on less favorable terms than the Company s existing debt. Refinancing may also negatively impact the Company s strategic alternatives initiative.

A change in the majority of the Board of Directors as a result of the pending proxy contest would also trigger an obligation to make payments under the Company s executive employment agreements (upon termination of employment by the executives during specified periods or in specified circumstances) and under the Company s severance and retention program.

## (7) Severance and Retention Incentive Program

The Company has established a Change of Control Severance and Retention Program (the Plan ), effective as of January 1, 2007, to provide severance benefits and a retention incentive to employees who are designated by the Plan Administrator as eligible for benefits under the Plan in the event of a Change in Control. The Company expects to pay approximately $11.4 million in retention incentives under the program during 2007.

The Company had in place a retention incentive plan that covered personnel who were employed by Northrock on September 27, 2005 (the date of acquisition) and were still employed by Northrock on September 27, 2006. On that latter date, the Company made payments of $13.4 million related to the retention incentive plan. The Company also made retention incentive plan payments of $2 million to those personnel who were employed by Latigo at both May 2, 2006, the date of acquisition, and November 2, 2006, six months thereafter.

## (8) 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 customers who have exceeded 10% of revenues in any given year (expressed in millions):

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Shell Trading Company | $ 96.4 | $ 117.5 | $ 147.1 |
| NGX | 146.6 | 19.3 | |

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

**(9)** Credit Risk

Substantially all of the Company s accounts receivable at December 31, 2006 and 2005, 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 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 of collection. As of December 31, 2006 and 2005, the Company s allowances for doubtful accounts were not material.

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

## **(10)** 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:

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| | (Expressed in millions) | | |
| **Long-Lived Assets:** | | | |
| As of December 31, | | | |
| United States | $ 3,751.3 | $ 2,624.7 | $ 2,538.2 |
| Canada | 2,805.8 | 2,659.7 | |
| Total | $ 6,557.1 | $ 5,284.4 | $ 2,538.2 |
| **Capital Expenditures:** | | | |
| (including interest capitalized) | | | |
| For the year ended December 31, | | | |
| United States | $ 1,676.8 | $ 397.2 | $ 931.4 |
| Canada | 345.5 | 2,681.8 | |
| Other International | 0.1 | | 5.7 |
| Total | $ 2,022.4 | $ 3,079.0 | $ 937.1 |
| **Revenues:** | | | |
| For the year ended December 31, | | | |
| United States* | $ 1,235.2 | $ 1,085.7 | $ 976.6 |
| Canada | 509.8 | 139.6 | |
| Other International | | 0.4 | |
| Total | $ 1,745.0 | $ 1,225.7 | $ 976.6 |
| **Depreciation, depletion, and amortization expense:** | | | |
| For the year ended December 31, | | | |
| United States | $ 285.2 | $ 261.3 | $ 251.9 |
| Canada | 199.4 | 50.9 | |
| Total | $ 484.6 | $ 312.2 | $ 251.9 |
| **Operating income (loss):** | | | |
| For the year ended December 31, | | | |
| United States* | $ 486.3 | $ 474.1 | $ 432.7 |
| Canada | 82.5 | 43.9 | |
| Other International | (6.5 ) | (9.6 ) | (6.4 ) |
| Total | $ 562.3 | $ 508.4 | $ 426.3 |

* Includes gain on sale of properties of $304.7 million in 2006.

## **(11)** 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.

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

*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 2004 and 2005. The summarized financial results and financial position data of the discontinued operations were as follows (amounts expressed in millions):

***Operating Results Data***

| | Year Ended December 31, 2005 | 2004 |
|---|---|---|
| Revenues | $ 252.8 | $ 335.3 |
| Costs and expenses | (126.5 ) | (237.1 ) |
| Other income | 5.0 | 0.3 |
| Income before income taxes | 131.3 | 98.5 |
| Income taxes | (78.5 ) | (85.8 ) |
| Income before gain from discontinued operations, net of tax | 52.8 | 12.7 |
| Gain on sale, net of tax of $9.7 million | 407.8 | |
| Income from discontinued operations, net of tax | $ 460.6 | $ 12.7 |

## (12) 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 $15,000 in 2006. 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 $1.9 million to the savings plan in 2006, $1.5 million in 2005, and $1.4 million in 2004.

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

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 2006 and 2005, the Company contributed $7.0 million and $4.5 million to the plan, respectively. The Company will continue to monitor the plan to determine whether a contribution will need to be made in 2007. The plan s investment strategy and goals are to ensure, over the long-term life of the retirement plan, an adequate pool of sufficiently liquid assets to support the benefit obligations to participants, retirees and beneficiaries. Investment objectives are long-term in nature covering typical market cycles of three to five years.

Although the Company has no obligation to do so, the Company currently provides full medical benefits to its retired U.S. employees and dependents. For current employees, the Company assumes all or a portion of post-retirement medical and term life insurance costs based on the employee s age and length of service with the Company. The post-retirement medical plan has no assets and is currently funded by the Company on a pay-as-you-go basis. The expected Company contributions to the post-retirement medical plan during 2007 are approximately $0.7 million.

The following two tables set forth the plans status (in millions of dollars) as of and for the years ended December 31 of the applicable year.

| | Retirement Plan 2006 | Retirement Plan 2005 | Post-Retirement Medical Plan 2006 | Post-Retirement Medical Plan 2005 |
|---|---|---|---|---|
| **Change in benefit obligation** | | | | |
| Benefit obligation at beginning of year | $ 46.6 | $ 36.9 | $ 21.9 | $ 21.2 |
| Service cost | 5.3 | 3.4 | 2.6 | 1.4 |
| Interest cost | 2.5 | 2.1 | 1.3 | 1.0 |
| Plan amendments | | | 1.6 | |
| Benefits paid | (6.2 ) | (2.4 ) | (0.4 ) | (0.4 ) |
| Actuarial loss | 5.1 | 6.6 | 2.5 | (1.3 ) |
| Benefit obligation at end of year | $ 53.3 | $ 46.6 | $ 29.5 | $ 21.9 |
| **Change in plan assets** | | | | |
| Fair value of plan assets at beginning of year | $ 35.7 | $ 32.3 | $ | $ |
| Actual return on plan assets | 4.9 | 1.6 | | |
| Employer contributions | 7.0 | 4.5 | 0.4 | 0.4 |
| Benefits paid | (6.2 ) | (2.4 ) | (0.4 ) | (0.4 ) |
| Administrative expenses | (0.4 ) | (0.3 ) | | |
| Fair value of plan assets at end of year | $ 41.0 | $ 35.7 | $ | $ |
| **Overfunded (underfunded) status** | $ (12.3 ) | $ (10.9 ) | $ (29.5 ) | $ (21.9 ) |
| **Reconciliation of funded status** | | | | |
| Funded status | $ (12.3 ) | $ (10.9 ) | $ (29.5 ) | $ (21.9 ) |
| Unrecognized actuarial loss | | 20.6 | | 3.8 |
| Unrecognized transition (asset) or obligation | | | | |
| Unrecognized prior service cost | | 0.6 | | |
| Net amount recognized | $ (12.3 ) | $ 10.3 | (29.5 ) | (18.1 ) |
| **Amount recognized in the statement of financial position** | | | | |
| Other assets | $ | $ 10.3 | $ | $ |
| Current liabilities | | | (0.7 ) | |
| Deferred credits | (12.3 ) | | (28.8 ) | (18.1 ) |
| **Net amount recognized** | $ (12.3 ) | $ 10.3 | (29.5 ) | (18.1 ) |
| **Accumulated benefit obligation** | $ 40.8 | $ 35.6 | | |

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

| | Retirement Plan | | | Post-Retirement Medical Plan | | |
|---|---|---|---|---|---|---|
| | 2006 | 2005 | 2004 | 2006 | 2005 | 2004 |
| Components of net periodic benefit cost | | | | | | |
| Service cost | $ 5.3 | $ 3.4 | $ 2.6 | $ 2.6 | $ 1.4 | $ 1.4 |
| Interest cost | 2.5 | 2.1 | 1.8 | 1.3 | 1.0 | 1.0 |
| Expected return on plan assets | (2.8) | (2.6) | (2.6) | | | |
| Amortization of prior service cost | 0.1 | 0.1 | | | | |
| Amortization of transition (asset) obligation | | | | | 0.3 | 0.3 |
| Amortization of net loss | 1.9 | 1.2 | 0.7 | 0.4 | | 0.2 |
| | $ 7.0 | $ 4.2 | $ 2.5 | $ 4.3 | $ 2.7 | $ 2.9 |

The balance in Accumulated Other Comprehensive Income (AOCI) at December 31, 2006 consists of the following components (in millions of dollars):

| | Retirement Plan | Post-Retirement Medical Plan |
|---|---|---|
| Actuarial loss | $ 0.3 | $ 0.9 |
| Prior service cost | 14.6 | 3.8 |
| Total | $ 14.9 | $ 4.7 |

Prior to the adoption of SFAS 158, the Company had no minimum pension liability that would have been reflected in AOCI.

The amounts in AOCI expected to be recognized as net periodic benefit expense over the next fiscal year are as follows (in millions of dollars):

| | Retirement Plan | Post-Retirement Medical Plan |
|---|---|---|
| Actuarial loss | $ 0.1 | $ 0.2 |
| Prior service cost | 2.0 | 0.4 |
| Total | $ 2.1 | $ 0.6 |

The following table shows the incremental effects (in millions) of applying FASB Statement No. 158 on individual line items in the statement of financial position as of December 31, 2006:

| | Before application of FAS 158 | Adjustments | After application of FAS 158 |
|---|---|---|---|
| Other assets | $ 51.1 | $ (10.3) | $ 40.8 |
| Total assets | 6,981.4 | (10.3) | 6,971.1 |
| Deferred credits | 27.4 | 20.5 | 47.9 |
| Deferred income taxes | 1,489.2 | (11.2) | 1,478.0 |
| Total liabilities | 4,394.4 | 9.3 | 4,403.7 |
| Accumulated OCI | 18.2 | (19.6) | (1.4) |
| Total shareholders equity | 2,587.0 | (19.6) | 2,567.4 |

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

*Plan Assumptions*

| | Retirement Plan | | | Post-Retirement Medical Plan | | |
|---|---|---|---|---|---|---|
| | 2006 | 2005 | 2004 | 2006 | 2005 | 2004 |
| **Plan assumptions to determine benefit obligations** | | | | | | |
| Discount rate | 5.75 % | 5.50 % | 5.75 % | 5.75 % | 5.50 % | 5.75 % |
| Rate of compensation increase | 5.50 % | 5.50 % | 5.50 % | | | |
| **Plan assumptions to determine net cost** | | | | | | |
| Discount rate | 5.50 % | 5.75 % | 6.00 % | 5.50 % | 5.75 % | 6.00 % |
| Expected long-term rate of return on plan assets | 8.50 % | 8.50 % | 8.50 % | | | |
| Rate of compensation increase | 5.50 % | 5.50 % | 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 2006.

The Company determines the discount rate used to measure plan liabilities as of the December 31 measurement date for both plans. 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. Additionally, the Company performs an analysis of the Citigroup Pension Discount Curve (CPDC) as of that date for both plans. The CPDC uses spot rates that represent the equivalent yield on high quality, zero coupon bonds for specific maturities. These rates were used to develop an equivalent single discount rate based on the plans expected future benefit payment streams and duration of plan liabilities. Using this methodology, the Company determined a discount rate of 5.75% to be appropriate as of December 31, 2006, which is an increase of 0.25 percentage points from the rate used as of December 31, 2005.

Expected benefit payments for the retirement and the post-retirement medical plans for the next ten years are as follows (expressed in millions):

| | Expected Benefit Payments | |
|---|---|---|
| Year Ending December 31, | Retirement Plan | Post-Retirement Medical Plan |
| 2007 | $ 3.5 | $ 0.7 |
| 2008 | 5.3 | 0.8 |
| 2009 | 5.0 | 0.9 |
| 2010 | 4.9 | 1.1 |
| 2011 | 6.1 | 1.2 |
| Next 5 Years | 37.8 | 7.8 |

**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, 2006 | 2005 |
|---|---|---|---|
| Equity securities | 100 % | 89 % | 87 % |
| Debt securities | 0 % | 0 % | 0 % |
| Real estate | 0 % | 0 % | 0 % |
| Other | 0 % | 11 % | 13 % |
| 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 2006. The rate is assumed to decrease gradually to 5% for 2013 and remain at that level thereafter. This compares to the amounts used for 2005 measurement purposes, where a 10% 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 millions):

| | One Percentage Point Increase | Decrease |
|---|---|---|
| Effect on total of service and interest cost components for 2006 | $ 0.8 | $ (0.7 ) |
| Effect on year-end 2006 post-retirement benefit obligation | $ 5.2 | $ (4.2 ) |

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. The Company has elected not to reflect changes in the Act in its 2006 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.

## (13) 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, Stock Awards ). Employee stock options generally become exercisable in three installments. Employee restricted stock generally vests in four installments. The number of shares of Company common stock available for future issuance was 3,284,524, 3,637,057, and 3,975,757 as of December 31, 2006, 2005, and 2004, respectively. Stock options granted during and after 2003 expire 5 years from the date of grant, if not exercised. Stock options granted prior to 2003, if not exercised, expire 10 years from the date of grant.

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

Effective January 1, 2003, the Company adopted the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, Accounting for Stock Based Compensation ( SFAS 123 ) and the prospective method transition provisions of Statement of Financial Accounting Standards 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. Under SFAS 123, the Company recognized compensation cost for all Stock Awards on either a straight-line basis over the vesting period or upon retirement, whichever was shorter (the nominal vesting period approach). On January 1, 2006, the Company adopted the provisions of SFAS No. 123 (revised 2004) ( SFAS 123R ), Share-Based Payment , which replaced the provisions of SFAS 123. The cumulative effect of the change in accounting principle resulting from the adoption of SFAS 123R was recognized in the Company s financial statements through the elimination of previously recognized deferred compensation costs, with offsetting amounts recorded in the additional paid in capital account within shareholders equity and the related deferred income tax payable. The Company adopted SFAS 123R using the modified prospective transition method. Under that transition method, compensation cost recognized during the twelve months ended December 31, 2006 includes (a) compensation cost for Stock Awards granted prior to, but not yet vested as of January 1, 2006, based on the grant date fair value estimated in accordance with the original provisions of SFAS 123, and (b) compensation cost for all Stock Award grants subsequent to January 1, 2006 based on the grant date fair value estimated in accordance with SFAS 123R. Compensation cost for restricted stock and stock options is recognized using the nonsubstantive vesting period approach, i.e. (a) on a straight-line basis, over either the vesting period for the applicable Stock Award or until retirement eligibility age, whichever is shorter, or (b) over a six-month period for Stock Awards to employees who have reached retirement eligibility age. The impact of using the nonsubstantive vs. the nominal vesting period approach would have resulted in a reduction in after-tax compensation expense of $1.0 million for the year ended December 31, 2006, and an increase in after-tax compensation expense of $3.1 million and $10.0 million for the years ended December 31, 2005, and 2004, respectively.

The following table illustrates the effect on the Company s net income and earnings per share if the fair value recognition provisions of SFAS 123R for employee stock-based compensation had been applied to all Stock Awards outstanding during the years ended December 31, 2005 and 2004 (in millions of dollars, except per share amounts):

| | Year Ended December 31, 2005 | 2004 |
|---|---|---|
| Net income, as reported | $ 750.7 | $ 261.7 |
| Add: Employee stock-based compensation expense, net of related tax effects, included in net income, as reported | 5.4 | 3.0 |
| Deduct: Total employee stock-based compensation expense, determined under fair value method for all awards, net of related tax effects | (6.8 ) | (6.7 ) |
| Net income, pro forma | $ 749.3 | $ 258.0 |
| Earnings per share: | | |
| Basic as reported | $ 12.43 | $ 4.10 |
| Basic pro forma | $ 12.41 | $ 4.04 |
| Diluted as reported | $ 12.32 | $ 4.06 |
| Diluted pro forma | $ 12.30 | $ 4.01 |

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

Restricted Stock

The fair value of restricted stock grants is estimated based on the average of the high and low share price on the date of grant. The Company granted the following shares of restricted stock during the periods indicated:

| Year Ended December 31, | Number of Awards | Weighted Average Grant Date Fair Value (in millions) |
|---|---|---|
| 2006 | 400,000 | $ 17.8 |
| 2005 | 351,800 | $ 19.5 |
| 2004 | 303,400 | $ 13.2 |

A summary of the status of the Company s unvested restricted stock activity during and as of the year ended December 31, 2006, is presented below:

| | Shares | Weighted Average Grant Date Fair Value |
|---|---|---|
| Unvested restricted stock: | | |
| Unvested at December 31, 2005 | 630,600 | $ 51.57 |
| Granted | 400,000 | $ 44.49 |
| Vested | (233,875 ) | $ 48.67 |
| Forfeited | (25,700 ) | $ 47.83 |
| Unvested at December 31, 2006 | 771,025 | $ 47.54 |

As of December 31, 2006, there was approximately $27.1 million of total unrecognized compensation cost related to unvested restricted stock that is expected to be recognized over a weighted average period of 1.5 years. Total compensation expense for restricted stock for the years ended December 31, 2006, 2005, and 2004 was $15.6 million ($9.9 million, net of tax), $7.1 million ($4.5 million, net of tax), and $3.3 million ($2.1 million, net of tax), respectively. The total fair value of shares that vested and were distributed during the years ended December 31, 2006, 2005 and 2004, was $10.7 million, $6.4 million, and $1.6 million, respectively, which resulted in the recognition of deferred tax assets in excess of the benefits of the tax deductions ( excess tax deficiencies ) of $0.3 for 2006, and the recognition of the benefits of the tax deductions in excess of deferred tax assets ( excess tax deductions ) of $0.5 million and $0.02 million for 2005 and 2004, respectively.

Stock Options

The Company granted options covering 30,000 shares of stock during the period ended December 31, 2004. Those options had a grant date fair market value of $0.3 million. No stock options were granted during 2005 or 2006. The fair value of previous stock option grants that vested in 2005 and 2006 was estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used for stock option grants made in 2004 and 2003, respectively: risk free interest

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

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. Total compensation expense for stock options for the years ended December 31, 2006, 2005, and 2004 was $0.7 million ($0.5 million, net of tax), $1.4 million ($0.9 million, net of tax) and $1.4 million ($0.9 million, net of tax), respectively. The total intrinsic value of stock options exercised during the years ended December 31, 2006, 2005, and 2004 was $2.7 million, $7.3 million, and $9.4 million respectively, resulting in excess tax deductions of $1.0 million, $2.7 million, and $3.3 million for the same respective periods. As of December 31, 2006, there was less than $0.1 million in unrecognized compensation cost related to unvested stock options that is expected to be recognized over a weighted average period of 4 months. The Company s current practice is to issue new shares to satisfy stock option exercises.

A summary of the Company s stock option activity during and as of the year ended December 31, 2006, is presented below:

| | Number of Awards | Weighted Average Exercise Price | Weighted Average Remaining Contractual Term | Aggregate Intrinsic Value (millions)(a) |
|---|---|---|---|---|
| Outstanding, December 31, 2005 | 1,782,236 | $ 29.69 | | |
| Exercised | (144,800 ) | $ 30.95 | | |
| Canceled | (15,867 ) | $ 43.11 | | |
| Outstanding, December 31, 2006 | 1,621,569 | $ 29.45 | 4.1 years | $ 31.6 |
| Exercisable, December 31, 2006 | 1,614,902 | $ 29.37 | 4.1 years | $ 31.6 |

(a) Calculated based on the exercise price of underlying awards and the quoted price of the Company s common stock as of the balance sheet date.

The following table summarizes information about stock options outstanding at December 31, 2006:

| | 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 | 841 | $ 18.30 | 47,500 | $ 18.30 |
| $20.31 to $24.77 | 607,101 | 1,519 | $ 23.30 | 607,101 | $ 23.30 |
| $25.38 to $29.78 | 604,600 | 1,966 | $ 29.58 | 604,600 | $ 29.58 |
| $31.18 to $33.94 | 40,000 | 1,988 | $ 31.36 | 40,000 | $ 31.36 |
| $40.63 to $43.46 | 304,034 | 510 | $ 41.82 | 304,034 | $ 41.82 |
| $45.89 to $49.48 | 18,334 | 860 | $ 48.38 | 11,667 | $ 48.50 |
| Total | 1,621,569 | 1,481 | $ 29.45 | 1,614,902 | $ 29.37 |

Restricted Stock Units

The Company awards 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.

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

The Company recognizes compensation expense and a liability over the vesting period based on the average fair market value of Company common stock for the last five trading days of the period. On October 31, 2006, 43,979 of the Units vested, which resulted in payments of $2 million. As of December 31, 2006, there were 239,133 unvested Units. For the years ended December 31, 2006, and 2005, the Company recognized compensation expense related to the Units of $2.4 million and $0.4 million, respectively.

## (14) Commodity Derivatives and Hedging Activities

During the year ended December 31, 2006, the Company recognized $2.7 million of pre-tax gains in its oil and gas revenues related to settled price hedge contracts, as well as a pre-tax gain of $3.4 million due to ineffectiveness on unsettled hedge contracts During the year ended December 31, 2005, the Company recognized $11.3 million of pre-tax losses in its oil and gas revenues from settled price hedge contracts, as well as a pre-tax loss of $1.3 million due to ineffectiveness on unsettled hedge contracts. During the year ended December 31, 2004, the Company did not recognize any gains or losses from its hedging activities related to 2004 production, but did recognize a pre-tax gain of $0.7 million due to ineffectiveness. Net unrealized gains on derivative instruments of $6.6 million, net of deferred taxes of $3.8 million, have been reflected as a component of other comprehensive income for the year ended December 31, 2006. Based on the fair market value of the hedge contracts as of December 31, 2006, the Company would reclassify additional pre-tax gains of approximately $6.2 million (approximately $3.9 million after taxes) from accumulated other comprehensive loss (shareholders equity) to net income during the next twelve months.

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

The estimated fair value of the Company s hedging 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 these hedging activities as of December 31, 2006 are as follows:

| Contract Period and Type of Contract | Volume | NYMEX Contract Price Floor | Ceiling | Fair Value of Asset/(Liability) (in millions) |
|---|---|---|---|---|
| ***Natural Gas Contracts (MMBtu)(a)*** | | | | |
| Collar Contracts: | | | | |
| January 2007 - December 2007 | 5,475 | $ 6.00 | $ 12.00 | $ 1.6 |
| January 2007 - December 2007 | 1,825 | $ 6.00 | $ 12.15 | $ 0.5 |
| January 2007 - December 2007 | 9,125 | $ 6.00 | $ 12.50 | $ 2.9 |
| January 2007 - December 2007 | 913 | $ 8.00 | $ 13.40 | $ 1.4 |
| January 2007 - December 2007 | 2,738 | $ 8.00 | $ 13.50 | $ 4.2 |
| January 2007 - December 2007 | 913 | $ 8.00 | $ 13.52 | $ 1.4 |
| January 2007 - December 2007 | 913 | $ 8.00 | $ 13.65 | $ 1.4 |
| January 2008 - December 2008 | 1,830 | $ 8.00 | $ 12.05 | $ 1.5 |
| January 2008 - December 2008 | 2,745 | $ 8.00 | $ 12.10 | $ 2.3 |
| January 2008 - December 2008 | 915 | $ 8.00 | $ 12.25 | $ 0.8 |
| ***Crude Oil Contracts (Barrels)*** | | | | |
| Collar Contracts: | | | | |
| January 2007 - December 2007 | 1,460,000 | $ 50.00 | $ 75.00 | $ (2.2 ) |
| January 2007 - December 2007 | 365,000 | $ 50.00 | $ 75.25 | $ (0.6 ) |
| January 2007 - December 2007 | 3,650,000 | $ 50.00 | $ 77.50 | $ (3.9 ) |
| January 2007 - December 2007 | 182,500 | $ 60.00 | $ 82.75 | $ 0.3 |
| January 2007 - December 2007 | 547,500 | $ 60.00 | $ 83.00 | $ 0.9 |
| January 2007 - December 2007 | 182,500 | $ 60.00 | $ 84.00 | $ 0.3 |
| January 2008 - December 2008 | 183,000 | $ 60.00 | $ 80.00 | $ 0.1 |
| January 2008 - December 2008 | 183,000 | $ 60.00 | $ 80.05 | $ 0.1 |
| January 2008 - December 2008 | 183,000 | $ 60.00 | $ 80.10 | $ 0.1 |
| January 2008 - December 2008 | 366,000 | $ 60.00 | $ 80.25 | $ 0.2 |

(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 sale of 50% of the Company s Gulf of Mexico interests on May 31, 2006 and the shut-in forecasted 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 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 income (expense). The Company recognized realized and unrealized gains (losses) related to these contracts of $7.3 million and ($13.6) million for the periods ended December 31, 2006, and 2005, respectively. As of December 31, 2006, 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 Asset/(Liability) (in millions) |
|---|---|---|---|---|
| ***Natural Gas Contracts (MMBtu)*** | | | | |
| Collar Contracts: | | | | |
| January 2007 - December 2007 | 7,300 | $ 6.00 | $ 12.15 | $ 2.2 |
| January 2007 - December 2007 | 3,650 | $ 6.00 | $ 12.20 | $ 1.1 |

## (15) Divestitures

On May 31, 2006, the Company sold an undivided 50 percent interest in each and all of its Gulf of Mexico oil and gas leasehold interests and related pipelines and equipment to an affiliate of Mitsui & Co., Ltd., for approximately $448.8 million, after purchase price adjustments. The sale resulted in a pre-tax gain of $302.7 million. This gain, along with $2 million of pre-tax gains on sales of other properties, has been reflected in the caption Gain (loss) on sale of properties in the Company s results of operations.

## (16) Asset Retirement Obligations

The Company accounts for future abandonment costs pursuant to SFAS 143, which 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.

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

Activity related to the Company s ARO during the years ended December 31, 2006 and 2005 is as follows (in thousands):

| | Year Ended December 31, 2006 | | 2005 | |
|---|---|---|---|---|
| Initial ARO as of January 1, | $ 156.4 | | $ 74.0 | |
| Liabilities incurred during period | 3.6 | (a) | 41.9 | (a) |
| Liabilities settled during period | (37.1 | )(b) | (7.1 | ) |
| Revisions to previous estimate | 33.5 | (c) | 39.7 | (c) |
| Accretion expense | 10.5 | | 7.9 | |
| Balance of ARO as of December 31, | $ 166.9 | | $ 156.4 | |
| Less: Current portion of ARO as of December 31, | (10.6 | ) | (7.0 | ) |
| Long term portion of ARO as of December 31, | $ 156.3 | | $ 149.4 | |

(a) $1.9 million and $39.1 million of this amount relates to acquistions during 2006 and 2005, respectively.

(b) $31.8 million of this amount relates to the sale of 50% of the Company s interest in its Gulf of Mexico properties

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

For the years ended December 31, 2006, 2005 and 2004, the Company recognized depreciation expense related to its ARC of $9.9 million, $4.5 million and $1.0 million, respectively.

## (17) Comprehensive Income

As of the indicated dates, the Company s comprehensive income consisted of the following (in millions):

| | Twelve Months Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| Net income | $ 446.2 | $ 750.7 | $ 261.7 |
| Foreign currency translation adjustment, net of tax of ($3.2) million and $10.2 million, respectively | (11.4 ) | 22.9 | |
| Change in fair value of price hedge contracts, net of tax of $39.1 million, ($41.5) million, and $1.6 million, respectively | 68.1 | (72.2 ) | 3.0 |
| Reclassification adjustment for hedge contract (gains) losses included in net income, net of tax of ($4.9) million, $9.6 million, and ($0.2) million, respectively | (8.5 ) | 16.7 | (0.4 ) |
| Comprehensive income | $ 494.4 | $ 718.1 | $ 264.3 |

## (18) 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.

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

*Receivables and Payables*

Fair value is approximately carrying value.

*Derivative Financial Instruments*

Fair value is carrying value.

*Debt and Other*

| Instrument | Basis of Fair Value Estimate |
|---|---|
| Bank revolving credit agreement(s) | Fair value is carrying value as of December 31, 2006 and 2005 based on the market value interest rates. |
| LIBOR rate advances | Fair value is carrying value as of December 31, 2006 and 2005 based on the market value interest rates. |
| 2011 Notes | Fair value is 102.5% and 104.1% of carrying value as of December 31, 2006 and 2005, based on quoted market value. |
| 2013 Notes | Fair value is 101.5% of carrying value as of December 31, 2006, based on quoted market value. |
| 2015 Notes | Fair value is 96.5% and 98.0% of carrying value as of December 31, 2006 and 2005, based on quoted market value. |
| 2017 Notes | Fair value is 96.0% and 97.1% of carrying value as of December 31, 2006 and 2005, based on quoted market value. |

The carrying value and estimated fair value of the Company s financial instruments at December 31, 2006 and 2005 (in millions of dollars) are as follows:

| | 2006 Carrying Value | Fair Value | 2005 Carrying Value | Fair Value |
|---|---|---|---|---|
| Cash and cash equivalents | $ 22.7 | $ 22.7 | $ 57.7 | $ 57.7 |
| Receivables | $ 223.4 | $ 223.4 | $ 218.7 | $ 218.7 |
| Payables | $ (340.3 ) | $ (340.3 ) | $ (304.5 ) | $ (304.5 ) |
| Debt: | | | | |
| Bank revolving credit agreement loans | $ (797.0 ) | $ (797.0 ) | $ (606.0 ) | $ (606.0 ) |
| LIBOR Rate Advances | $ (75.0 ) | $ (75.0 ) | $ (40.0 ) | $ (40.0 ) |
| 2011 Notes | $ (200.0 ) | $ (205.0 ) | $ (200.0 ) | $ (208.3 ) |
| 2013 Notes | $ (450.0 ) | $ (456.8 ) | $ | $ |
| 2015 Notes | $ (297.7 ) | $ (287.3 ) | $ (297.5 ) | $ (291.4 ) |
| 2017 Notes | $ (500.0 ) | $ (480.0 ) | $ (500.0 ) | $ (485.6 ) |

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

**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 millions) 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 indicated, the Total amounts reflect only those activities related to the Company s continuing operations.

| | 2006 Other International | Canada | United States | Total |
|---|---|---|---|---|
| Revenues | $ | $ 450.7 | $ 924.7 | $ 1,375.4 |
| Lease operating expense | | (81.4) | (183.4) | (264.8) |
| Exploration expense | (3.8) | (15.9) | (12.1) | (31.8) |
| Dry hole and impairment expense | | (25.7) | (80.9) | (106.6) |
| Depreciation, depletion and amortization expense | | (197.6) | (278.8) | (476.4) |
| Production and other taxes | | (10.8) | (67.6) | (78.4) |
| Transportation and accretion | (0.6) | (9.7) | (29.9) | (40.2) |
| Pretax operating results | (4.4) | 109.6 | 272.0 | 377.2 |
| Income tax (expense) benefit | 2.5 | 100.1 | (111.9) | (9.3) |
| Operating results from continuing operations | $ (1.9) | $ 209.7 | $ 160.1 | $ 367.9 |

| | 2005 Other International | Canada | United States | Total |
|---|---|---|---|---|
| Revenues | $ | $ 134.1 | $ 1,082.1 | $ 1,216.2 |
| Lease operating expense | | (17.7) | (136.0) | (153.7) |
| Exploration expense | (9.0)(a) | (3.4) | (14.1) | (26.5) |
| Dry hole and impairment expense | | (5.0) | (82.2) | (87.2) |
| Depreciation, depletion and amortization expense | | (50.5) | (256.6) | (307.1) |
| Production and other taxes | | (2.7) | (56.8) | (59.5) |
| Transportation and accretion | | (2.2) | (25.0) | (27.2) |
| Pretax operating results | (9.0) | 52.6 | 511.4 | 555.0 |
| Income tax (expense) benefit | | (18.1) | (182.4) | (200.5) |
| Operating results from continuing operations(b) | $ (9.0) | $ 34.5 | $ 329.0 | $ 354.5 |

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

| | 2004<br>Other<br>International | United<br>States | Total |
|---|---|---|---|
| Revenues | $ | $ 973.1 | $ 973.1 |
| Lease operating expense | | (100.5 ) | (100.5 ) |
| Exploration expense | | (21.7 ) | (21.7 ) |
| Dry hole and impairment expense | (5.5 )(c) | (56.1 ) | (61.6 ) |
| Depreciation, depletion and amortization expense | | (248.5 ) | (248.5 ) |
| Production and other taxes | | (44.1 ) | (44.1 ) |
| Transportation and accretion | | (19.5 ) | (19.5 ) |
| Pretax operating results | (5.5 ) | 482.7 | 477.2 |
| Income tax (expense) benefit | | (175.6 ) | (175.6 ) |
| Operating results from continuing operations(b) | $ (5.5 ) | $ 307.1 | $ 301.6 |

(a) Related to New Zealand.

(b) Excludes operating results from discontinued operations of $52.9 million in 2005 and $28.8 million in 2004.

(c) Related to the Danish North Sea.

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

| | **2006**<br>**Other International** | **Canada** | **United States** | **Total** |
|---|---|---|---|---|
| Costs incurred (capitalized unless otherwise indicated): | | | | |
| Property acquisition | | | | |
| Proved | $ | $ 21.4 | $ 1,046.2 | $ 1,067.6 |
| Unproved | | 15.4 | 67.1 | 82.5 |
| Exploration | | | | |
| Capitalized | 0.1 | 75.1 | 155.2 | 230.4 |
| Expensed | 3.8 | 15.9 | 12.1 | 31.8 |
| Development | | 230.9 | 406.3 | 637.2 |
| Asset retirement cost | | (2.4 ) | 39.9 | 37.5 |
| Total oil and gas costs incurred | $ 3.9 | $ 356.3 | $ 1,726.8 | $ 2,087.0 |

| | **2005**<br>**Other International** | **Canada** | **United States** | **Total** | **Discontinued Operations** |
|---|---|---|---|---|---|
| Property acquisition | | | | | |
| Proved | $ | $ 1,786.9 | $ 46.0 | $ 1,832.9 | $ |
| Unproved | | 830.0 | 50.8 | 880.8 | |
| Exploration | | | | | |
| Capitalized | | 9.1 | 130.1 | 139.2 | 1.3 |
| Expensed | 9.1 | 3.4 | 14.0 | 26.5 | |
| Development | 0.1 | 55.8 | 164.2 | 220.1 | 69.6 |
| Asset retirement cost | | 49.9 | 3.3 | 53.2 | |
| Total oil and gas costs incurred | $ 9.2 | $ 2,735.1 | $ 408.4 | $ 3,152.7 | $ 70.9 |

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

| | 2004<br>Other<br>International | Canada | United<br>States | Total | Discontinued<br>Operations |
|---|---|---|---|---|---|
| Property acquisition | | | | | |
| Proved | $ | $ | $ 613.0 | $ 613.0 | $ |
| Unproved | | | 26.9 | 26.9 | |
| Exploration | | | | | |
| Capitalized | 5.6 | | 57.0 | 62.6 | 35.1 |
| Expensed | | | 21.7 | 21.7 | 1.5 |
| Development | | | 228.5 | 228.5 | 114.2 |
| Asset retirement cost | | | 14.3 | 14.3 | 4.0 |
| Total oil and gas costs incurred | $ 5.6 | $ | $ 961.4 | $ 967.0 | $ 154.8 |

**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 for continuing operations and were located offshore in the Kingdom of Thailand and in Hungary for discontinued operations, is based on reports prepared by Ryder Scott Company, L.P. ( Ryder Scott ) and reports prepared by the Company and reviewed by Ryder Scott, for certain of its domestic properties acquired from Latigo, Ryder Scott Company Canada ( Ryder Scott Canada ), for all of its Canadian properties, and Miller and Lents, Ltd. ( Miller and Lents ), for certain onshore Gulf Coast and Rocky Mountain properties. 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. Only reserves data related to the Company s continuing operations is presented under the Total amounts.

**Estimates of Proved Reserves**

**Oil, Condensate and Natural Gas Liquids (Bbls.)**

| | Canada | United States | Total | Discontinued Operations |
|---|---|---|---|---|
| Proved Reserves as of December 31, 2003 | | 77,552,530 | 77,552,530 | 37,317,479 |
| Revisions of previous estimates | | 5,012,763 | 5,012,763 | (730,971 ) |
| Extensions, discoveries and other additions | | 1,727,761 | 1,727,761 | 2,469,912 |
| Purchase of properties | | 13,775,000 | 13,775,000 | |
| Sale of properties | | (1,832,000 ) | (1,832,000 ) | |
| Estimated 2004 production | | (12,370,000 ) | (12,370,000 ) | (6,540,000 ) |
| Proved Reserves as of December 31, 2004 | | 83,866,054 | 83,866,054 | 32,516,420 |
| Revisions of previous estimates | (23,300 ) | 5,537,272 | 5,513,972 | |
| Extensions, discoveries and other additions | 3,083,600 | 1,801,097 | 4,884,697 | |
| Purchase of properties | 60,100,000 | 588,379 | 60,688,379 | |
| Sale of properties | | | | (28,496,442 ) |
| Estimated 2005 production | (1,357,312 ) | (9,554,925 ) | (10,912,237 ) | (4,019,978 ) |
| Proved Reserves as of December 31, 2005 | 61,802,988 | 82,237,877 | 144,040,865 | |
| Revisions of previous estimates | 1,102,519 | 8,508,423 | 9,610,942 | |
| Extensions, discoveries and other additions | 6,896,000 | 8,503,900 | 15,399,900 | |
| Purchase of properties | 186,000 | 23,421,000 | 23,607,000 | |
| Sale of properties | | (15,846,500 ) | (15,846,500 ) | |
| Estimated 2006 production | (5,370,507 ) | (8,106,770 ) | (13,477,277 ) | |
| Proved Reserves as of December 31, 2006 | 64,617,000 | 98,717,930 | 163,334,930 | |
| Proved Developed Reserves as of: | | | | |
| December 31, 2003 | | 67,391,031 | 67,391,031 | 19,878,246 |
| December 31, 2004 | | 72,968,008 | 72,968,008 | 19,606,216 |
| December 31, 2005 | 55,413,014 | 63,160,705 | 118,573,719 | |
| December 31, 2006 | 55,917,925 | 67,685,050 | 123,602,975 | |

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

**Estimates of Proved Reserves**

**Natural Gas (MMcf)**

| | Canada | United States | Total | Discontinued Operations |
|---|---|---|---|---|
| Proved Reserves as of December 31, 2003 | | 837,004 | 837,004 | 175,319 |
| Revisions of previous estimates | | (16,357) | (16,357) | (4,497) |
| Extensions, discoveries and other additions | | 33,610 | 33,610 | 4,038 |
| Purchase of properties | | 172,022 | 172,022 | |
| Sale of properties | | (2,888) | (2,888) | |
| Estimated 2004 production | | (89,410) | (89,410) | (29,171) |
| Proved Reserves as of December 31, 2004 | | 933,981 | 933,981 | 145,689 |
| Revisions of previous estimates | 954 | 6,280 | 7,234 | |
| Extensions, discoveries and other additions | 32,646 | 29,063 | 61,709 | |
| Purchase of properties | 259,610 | 6,500 | 266,110 | |
| Sale of properties | | | | (127,926) |
| Estimated 2005 production | (6,783) | (84,526) | (91,309) | (17,763) |
| Proved Reserves as of December 31, 2005 | 286,427 | 891,298 | 1,177,725 | |
| Revisions of previous estimates | (15,028) | (63,162) | (78,190) | |
| Extensions, discoveries and other additions | 69,410 | 73,885 | 143,295 | |
| Purchase of properties | 5,990 | 134,477 | 140,467 | |
| Sale of properties | | (48,288) | (48,288) | |
| Estimated 2006 production | (28,486) | (73,553) | (102,039) | |
| Proved Reserves as of December 31, 2006 | 318,313 | 914,657 | 1,232,970 | |
| Proved Developed Reserves as of: | | | | |
| December 31, 2003 | | 702,836 | 702,836 | 77,938 |
| December 31, 2004 | | 769,753 | 769,753 | 83,095 |
| December 31, 2005 | 220,704 | 685,301 | 906,005 | |
| December 31, 2006 | 236,791 | 701,550 | 938,341 | |

**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 (expressed in millions) 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, 2006 | | |
|---|---|---|---|
| | Canada | United States | Total |
| Future gross revenues | $ 4,275.5 | $ 10,063.5 | $ 14,339.0 |
| Future production costs | (1,315.4) | (2,878.5) | (4,193.9) |
| Future development and abandonment costs | (251.4) | (1,324.5) | (1,575.9) |
| Future net cash flows before income taxes | 2,708.7 | 5,860.5 | 8,569.2 |
| Discount at 10% per annum | (1,209.8) | (2,881.3) | (4,091.1) |
| Discounted future net cash flows before income taxes | 1,498.9 | 2,979.2 | 4,478.1 |
| Future income taxes, net of discount at 10% per annum | (343.3) | (781.9) | (1,125.2) |
| Standardized measure of discounted future net cash flows related to proved oil and gas reserves | $ 1,155.6 | $ 2,197.3 | $ 3,352.9 |

| | Year Ended December 31, 2005 | | |
|---|---|---|---|
| | Canada | United States | Total |
| Future gross revenues | $ 4,834.5 | $ 11,670.4 | $ 16,504.9 |
| Future production costs | (1,169.8) | (2,585.1) | (3,754.9) |
| Future development and abandonment costs | (204.5) | (709.6) | (914.1) |
| Future net cash flows before income taxes | 3,460.2 | 8,375.7 | 11,835.9 |
| Discount at 10% per annum | (1,506.1) | (3,709.2) | (5,215.3) |
| Discounted future net cash flows before income taxes | 1,954.1 | 4,666.5 | 6,620.6 |
| Future income taxes, net of discount at 10% per annum | (612.7) | (1,445.1) | (2,057.8) |
| Standardized measure of discounted future net cash flows related to proved oil and gas reserves | $ 1,341.4 | $ 3,221.4 | $ 4,562.8 |

**POGO PRODUCING COMPANY & SUBSIDIARIES**

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

| | Year Ended December 31, 2004 | | |
|---|---|---|---|
| | United States | Total | Discontinued Operations |
| Future gross revenues | $ 8,850.2 | $ 8,850.2 | $ 1,724.3 |
| Future production costs | (2,123.5 ) | (2,123.5 ) | (406.0 ) |
| Future development and abandonment costs | (437.1 ) | (437.1 ) | (143.6 ) |
| Future net cash flows before income taxes | 6,289.6 | 6,289.6 | 1,174.7 |
| Discount at 10% per annum | (2,650.3 ) | (2,650.3 ) | (242.0 ) |
| Discounted future net cash flows before income taxes | 3,639.3 | 3,639.3 | 932.7 |
| Future income taxes, net of discount at 10% per annum | (1,080.6 ) | (1,080.6 ) | (395.8 ) |
| Standardized measure of discounted future net cash flows related to proved oil and gas reserves | $ 2,558.7 | $ 2,558.7 | $ 536.9 |

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

| | For the Year Ended December 31, 2006 | | |
|---|---|---|---|
| | Canada | United States | Total |
| Beginning balance | $ 1,341.4 | $ 3,221.4 | $ 4,562.8 |
| Revisions to prior years proved reserves: | | | |
| Net changes in prices and production costs | (433.8 ) | (1,350.5 ) | (1,784.3 ) |
| Net changes due to revisions in quantity estimates | (20.3 ) | (30.5 ) | (50.8 ) |
| Net changes in estimates of future development costs | (87.0 ) | (570.0 ) | (657.0 ) |
| Accretion of discount | 195.4 | 466.6 | 662.0 |
| Changes in production rate and other | (117.4 ) | 216.4 | 99.0 |
| Total revisions | (463.1 ) | (1,268.0 ) | (1,731.1 ) |
| New field discoveries and extensions, net of future production and development costs | 224.4 | 233.2 | 457.6 |
| Purchases of properties | 15.8 | 616.3 | 632.1 |
| Sales of properties | | (940.6 ) | (940.6 ) |
| Sales of oil and gas produced, net of production costs | (348.8 ) | (652.3 ) | (1,001.1 ) |
| Previously estimated development costs incurred | 116.6 | 324.2 | 440.8 |
| Net change in income taxes | 269.3 | 663.1 | 932.4 |
| Net change in standardized measure of discounted future net cash flows | (185.8 ) | (1,024.1 ) | (1,209.9 ) |
| Ending balance | $ 1,155.6 | $ 2,197.3 | $ 3,352.9 |

**POGO PRODUCING COMPANY & SUBSIDIARIES**

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

| | For the Year Ended December 31, 2005 | | | |
|---|---|---|---|---|
| | Canada | United States | Total | Discontinued Operations |
| Beginning balance | $ | $ 2,558.7 | $ 2,558.7 | $ 536.8 |
| Revisions to prior years proved reserves: | | | | |
| Net changes in prices and production costs | | 1,528.3 | 1,528.3 | |
| Net changes due to revisions in quantity estimates | (7.6 ) | 150.0 | 142.4 | |
| Net changes in estimates of future development costs | | (334.6 ) | (334.6 ) | |
| Accretion of discount | | 363.9 | 363.9 | 54.4 |
| Changes in production rate and other | 369.5 | (154.1 ) | 215.4 | |
| Total revisions | 361.9 | 1,553.5 | 1,915.4 | 54.4 |
| New field discoveries and extensions, net of future production and development costs | 193.9 | 145.5 | 339.4 | |
| Purchases of properties | 1,509.8 | 32.2 | 1,542.0 | |
| Sales of properties | | | | (819.4 ) |
| Sales of oil and gas produced, net of production costs | (111.5 ) | (864.5 ) | (976.0 ) | (197.2 ) |
| Previously estimated development costs incurred | | 160.4 | 160.4 | 29.6 |
| Net change in income taxes | (612.7 ) | (364.4 ) | (977.1 ) | 395.8 |
| Net change in standardized measure of discounted future net cash flows | 1,341.4 | 662.7 | 2,004.1 | (536.8 ) |
| Ending balance | $ 1,341.4 | $ 3,221.4 | $ 4,562.8 | $ |

| | For the Year Ended December 31, 2004 | | |
|---|---|---|---|
| | United States | Total | Discontinued Operations |
| Beginning balance | $ 2,009.1 | $ 2,009.1 | $ 440.9 |
| Revisions to prior years proved reserves: | | | |
| Net changes in prices and production costs | 631.1 | 631.1 | 237.0 |
| Net changes due to revisions in quantity estimates | 39.7 | 39.7 | (14.4 ) |
| Net changes in estimates of future development costs | (154.7 ) | (154.7 ) | (7.0 ) |
| Accretion of discount | 292.9 | 292.9 | 76.1 |
| Changes in production rate and other | (51.2 ) | (51.2 ) | 7.8 |
| Total revisions | 757.8 | 757.8 | 299.5 |
| New field discoveries and extensions, net of future production and development costs | 126.2 | 126.2 | 86.8 |
| Purchases of properties | 596.2 | 596.2 | |
| Sales of properties | (58.6 ) | (58.6 ) | |
| Sales of oil and gas produced, net of production costs | (809.0 ) | (809.0 ) | (265.2 ) |
| Previously estimated development costs incurred | 98.1 | 98.1 | 50.1 |
| Net change in income taxes | (161.1 ) | (161.1 ) | (75.3 ) |
| Net change in standardized measure of discounted future net cash flows | 549.6 | 549.6 | 95.9 |
| Ending balance | $ 2,558.7 | $ 2,558.7 | $ 536.8 |

**Quarterly Results Unaudited**

Summaries of the Company s results of operations by quarter for the years 2006 and 2005 are as follows:

| | Quarter Ended Mar. 31 | June 30 | Sept. 30 | Dec. 31 |
|---|---|---|---|---|
| | (Expressed in millions, except per share amounts) | | | |
| **2006** | | | | |
| Revenues | $ 373.5 | $ 674.6 (d) | $ 353.8 | $ 343.1 |
| Gross profit(a) | $ 139.0 | $ 438.5 (d) | $ 88.5 | $ 25.8 |
| Net income (loss) | $ 67.5 | $ 361.9 (d) | $ 33.3 | $ (16.5 ) |
| Earnings per share(b): | | | | |
| Basic | $ 1.18 | $ 6.31 | $ 0.58 | $ (0.29 ) |
| Diluted | $ 1.16 | $ 6.25 | $ 0.58 | $ (0.29 ) |
| **2005** | | | | |
| Revenues | $ 255.8 | $ 274.5 | $ 275.8 | $ 419.6 |
| Gross profit(a) | $ 92.4 | $ 144.7 | $ 152.3 | $ 206.3 |
| Income from continuing operations | $ 39.5 | $ 74.0 | $ 61.9 | $ 114.8 |
| Income (loss) from discontinued operations, net of tax | $ 19.7 | $ 29.5 | $ 411.6 (c) | $ (0.2 ) |
| Net income | $ 59.2 | $ 103.5 | $ 473.5 | $ 114.5 |
| 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 | $ 0.62 | $ 1.22 | $ 1.03 | $ 1.96 |
| Income (loss) from discontinued operations | $ 0.31 | $ 0.48 | $ 6.86 | $ |
| Diluted earnings per share | $ 0.93 | $ 1.70 | $ 7.89 | $ 1.96 |

(a) Represents revenues less lease operating, production and other taxes, 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.

(d) Includes a pretax gain of $302.7 million from the sale of an undivided 50% of the Company s Gulf of Mexico oil and gas leasehold interests and related pipelines and equipment to an affiliate of Mitsui & Co., Ltd.

**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, 2006. The Company excluded Latigo Petroleum, Inc. from its assessment of internal control over financial reporting as of December 31, 2006 because Latigo was acquired on May 2, 2006. Latigo is a wholly-owned subsidiary of the Company whose total assets and total revenues represent 16% and 5%, respectively, of the related consolidated financial statement amounts, as of and for the year ended December 31, 2006.

The Company s management s assessment of the effectiveness of its internal control over financial reporting as of December 31, 2006 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, Executive Officers and Corporate Governance.*

The information responsive to Items 401, 405, 406 and 407(c)(3), (d)(4) and (d)(5) of Regulation S-K in the Company s definitive Proxy Statement for its annual meeting to be held on May 15, 2007, to be filed within 120 days of December 31, 2006 pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended (the Company s 2007 Proxy Statement ), is incorporated herein by reference. See also Item S-K 401(b) appearing in Part I of this Form 10-K.

On May 25, 2006, the chief executive officer of the Company filed with the New York Stock Exchange ( NYSE ) the annual certification required by Section 303A.12(a) of the NYSE Listed Company Manual indicating that he was not aware of any violation by the Company of NYSE corporate governance listing standards. The Company has also filed as exhibits to this Form 10-K the certifications required by Section 302 of the Sarbanes-Oxley Act.

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

The information responsive to Items 402 and 407(e)(4) and (e)(5) of Regulation S-K in the Company s 2007 Proxy Statement is incorporated herein by reference. The portion of the incorporated material consisting of the Report of the Compensation Committee on Executive Compensation 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 2007 Proxy Statement is incorporated herein by reference.

**ITEM 13.** *Certain Relationships and Related Transactions, and Director Independence.*

The information responsive to Items 404 and 407(a) of Regulation S-K in the Company s 2007 Proxy Statement is incorporated herein by reference.

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

The information responsive to Item 9(e) of Schedule 14A in the Company s 2007 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 | Agreement and Plan of Merger dated April 13, 2006 by and among Latigo Petroleum, Inc., Pogo Producing Company and Pogo Merger Sub 1, Inc. (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, 2006, File No. 1-7792). |
| *2.2 | Purchase and Sale Agreement dated April 20, 2006 between Pogo Producing Company and MitEnergy Upstream LLC (a copy of any omitted schedule will be furnished supplementally to the Commission upon request) (Exhibit 2.2, Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, File No. 1-7792). |
| *2.3 | 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). |
| *2.4 | 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 | Indenture dated as of June 6, 2006 between Pogo Producing Company and The Bank of New York Trust Company N.A. (Exhibit 4.1 of the Company s Current Report on Form 8-K filed June 8, 2006, File No. 1-7792). |
| *4.8 | Form of 7.875% Senior Subordinated Note (Exhibit 4.1 of the Company s Current Report on Form 8-K filed June 8, 2006, File No. 1-7792). |
| *4.9 | Registration Rights Agreement dated as of June 6, 2006 among Pogo Producing Company and the initial purchasers named therein (Exhibit 4.2 of the Company s Current Report on Form 8-K filed June 8, 2006, File No. 1-7792). |
| *4.10 | 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). |
| *4.11 | 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). |
| *4.12 | 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). |

*4.13 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).

*4.14 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).

*4.15 Senior Loan Facility dated May 2, 2006 by and among Pogo Producing Company, as the Borrower, certain Lenders party thereto from time to time and Goldman Sachs Credit Partners L.P., as the sole Lead Arranger and Book Runner, Syndication Agent, Administration Agent and Lender (Exhibit 4.1 of the Company s Current Report on Form 8-K filed May 8, 2006, 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, 2006. 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 10.41, inclusive)**

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

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

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

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

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

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

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

*10.8 Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Paul G. Van Wagenen, dated February 1, 2005 (Exhibit 10.8, Annual Report on Form 10-K for the year ended December 31, 2004).

*10.9 Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Stephen R. Brunner, dated February 1, 2005 (Exhibit 10.9, Annual Report on Form 10-K for the year ended December 31, 2004).

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| *10.10 | Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Jerry A. Cooper, dated February 1, 2005 (Exhibit 10.10, Annual Report on Form 10-K for the year ended December 31, 2004). |
| *10.11 | Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and John O. McCoy, Jr., dated February 1, 2005 (Exhibit 10.11, Annual Report on Form 10-K for the year ended December 31, 2004). |
| *10.12 | Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and David R. Beathard, dated February 1, 2005 (Exhibit 10.12, Annual Report on Form 10-K for the year ended December 31, 2004). |
| *10.13 | Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Radford P. Laney, dated February 1, 2005 (Exhibit 10.13, Annual Report on Form 10-K for the year ended December 31, 2004). |
| *10.14 | Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and J. Don McGregor, dated February 1, 2005 (Exhibit 10.14, Annual Report on Form 10-K for the year ended December 31, 2004). |
| *10.15 | Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Gerald A. Morton, dated February 1, 2005 (Exhibit 10.15, Annual Report on Form 10-K for the year ended December 31, 2004). |
| *10.16 | Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and James P. Ulm, II, dated February 1, 2005 (Exhibit 10.16, Annual Report on Form 10-K for the year ended December 31, 2004). |
| *10.17 | Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Bruce E. Archinal, dated February 1, 2005 (Exhibit 10.18, Annual Report on Form 10-K for the year ended December 31, 2004). |
| *10.18 | Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Michael J. Killelea, dated February 1, 2005 (Exhibit 10.19, Annual Report on Form 10-K for the year ended December 31, 2004). |
| *10.19 | Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Paul G. Van Wagenen, dated August 1, 2006. (Exhibit 10.1, Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File No. 1-7792). |
| *10.20 | Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Stephen R. Brunner, dated August 1, 2006. (Exhibit 10.2, Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File No. 1-7792). |
| *10.21 | Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Jerry A. Cooper, dated August 1, 2006. (Exhibit 10.3, Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File No. 1-7792). |
| *10.22 | Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and John O. McCoy, Jr., dated August 1, 2006. (Exhibit 10.4, Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File No. 1-7792). |

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| *10.23 | Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and David R. Beathard, dated August 1, 2006. (Exhibit 10.5, Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File No. 1-7792). |
| *10.24 | Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Radford P. Laney, dated August 1, 2006. (Exhibit 10.6, Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File No. 1-7792). |
| *10.25 | Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and J. Don McGregor, dated August 1, 2006. (Exhibit 10.7, Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File No. 1-7792). |
| *10.26 | Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Gerald A. Morton, dated August 1, 2006. (Exhibit 10.8, Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File No. 1-7792). |
| *10.27 | Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and James P. Ulm, II, dated August 1, 2006. (Exhibit 10.9, Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File No. 1-7792). |
| *10.28 | Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Bruce E. Archinal, dated August 1, 2006. (Exhibit 10.10, Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File No. 1-7792). |
| *10.29 | Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Michael J. Killelea, dated August 1, 2006. (Exhibit 10.11, Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, File No. 1-7792). |
| *10.30 | Indemnification Agreement by and between Pogo Producing Company and Jerry M. Armstrong, dated April 25, 2006. (Exhibit 10.1, Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-7792). |
| *10.31 | Indemnification Agreement by and between Pogo Producing Company and Robert H. Campbell, dated April 25, 2006. (Exhibit 10.2, Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-7792). |
| *10.32 | Indemnification Agreement by and between Pogo Producing Company and William L Fisher, dated April 25, 2006. (Exhibit 10.3, Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-7792). |
| *10.33 | Indemnification Agreement by and between Pogo Producing Company and Thomas A. Fry, III, dated April 25, 2006. (Exhibit 10.4, Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-7792). |
| *10.34 | Indemnification Agreement by and between Pogo Producing Company and Gerrit W. Gong, dated April 25, 2006. (Exhibit 10.5, Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-7792). |

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| *10.35 | Indemnification Agreement by and between Pogo Producing Company and Charles G. Groat, dated April 25, 2006. (Exhibit 10.6, Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-7792). |
| *10.36 | Indemnification Agreement by and between Pogo Producing Company and Carroll W. Suggs, dated April 25, 2006. (Exhibit 10.7, Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-7792). |
| *10.37 | Indemnification Agreement by and between Pogo Producing Company and Paul G. Van Wagenen, dated April 25, 2006. (Exhibit 10.8, Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-7792). |
| *10.38 | Indemnification Agreement by and between Pogo Producing Company and Stephen A. Wells, dated April 25, 2006. (Exhibit 10.9, Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-7792). |
| *10.39 | 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). |
| *10.40 | 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). |
| *10.41 | 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). |
| 10.42 | Pogo Producing Company Change of Control Severance and Retention Program |
| 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. |
| 23.5 | Consent of Ryder Scott Company, L.P. |
| 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, 2006. |
| 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, 2006. |
| 99.2 | Summary Report of Ryder Scott Company Canada for the year ended December 31, 2006. |
| 99.3 | Summary Report of Miller and Lents, Ltd. for the year ended December 31, 2006. |
| 99.4 | Summary Report of Ryder Scott Company, L.P. for the year ended December 31, 2006. |
| *99.5 | Summary Report of Ryder Scott Company, L.P. for the year ended December 31, 2005 (Exhibit 99.1, Amendment No. 1 on Form 10-K/A, filed October 27, 2006, to the Company s Annual Report on Form 10-K for the year ended December 31, 2005). |

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| *99.6 | Summary Report of Ryder Scott Company Canada for the year ended December 31, 2005 (Exhibit 99.2, Amendment No. 1 on Form 10-K/A, filed October 27, 2006, to the Company s Annual Report on Form 10-K for the year ended December 31, 2005). |
| *99.7 | Summary Report of Miller and Lents, Ltd. for the year ended December 31, 2005 (Exhibit 99.3, Amendment No. 1 on Form 10-K/A, filed October 27, 2006, to the Company s Annual Report on Form 10-K for the year ended December 31, 2005). |
| *99.8 | 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). |
| *99.9 | 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). |

* 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 1, 2007

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 1, 2007.

| Signatures | Title |
|---|---|
| /s/ PAUL G. VAN WAGENEN<br>**Paul G. Van Wagenen**<br>*Chairman, President and Chief Executive Officer* | Principal Executive Officer and Director |
| /s/ JAMES P. ULM, II<br>**James P. Ulm, II**<br>*Senior Vice President and Chief Financial Officer* | Principal Financial Officer |
| /s/ ROBERT C. MARLOWE<br>**Robert C. Marlowe**<br>*Vice President Accounting* | Principal Accounting Officer |
| /s/ JERRY M. ARMSTRONG<br>**Jerry M. Armstrong** | Director |
| /s/ ROBERT H. CAMPBELL<br>**Robert H. Campbell** | Director |
| /s/ THOMAS A. FRY, III<br>**Thomas A. Fry, III** | Director |
| /s/ GERRIT W. GONG<br>**Gerrit W. Gong** | Director |
| /s/ CHARLES G. GROAT<br>**Charles G. Groat** | Director |

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| /s/ CARROLL W. SUGGS<br>**Carroll W. Suggs** | Director |
| /s/ STEPHEN A. WELLS<br>**Stephen A. Wells** | Director |
| /s/ ROBERT C. MARLOWE<br>**Robert C. Marlowe**<br>*Attorney-in-Fact* | |