

POGO PRODUCING CO
Form 10-K
March 01, 2007

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2006

OR

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

For the transition period from _____ to _____

Commission file number: 1-7792

Pogo Producing Company

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of
incorporation or organization)

74-1659398
(I.R.S. Employer
Identification No.)

5 Greenway Plaza, P.O. Box 2504, Houston, Texas
(Address of principal executive offices)

77252-2504
(Zip Code)

(713) 297-5000

(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, \$1.00 par value per share	New York Stock Exchange 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 No

Edgar Filing: POGO PRODUCING CO - Form 10-K

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 No

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

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

Indicate by check mark whether the registrant is 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 Accelerated filer Non-accelerated filer

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

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. Such 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.

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

8

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.

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.

Edgar Filing: POGO PRODUCING CO - Form 10-K

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 Productive	Dry	2005 Productive	Dry	2004 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

Edgar Filing: POGO PRODUCING CO - Form 10-K

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.

Edgar Filing: POGO PRODUCING CO - Form 10-K

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).

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

Edgar Filing: POGO PRODUCING CO - Form 10-K

	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		2004	% Change	
			2005 to 2006			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	%
Mcf 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.

Edgar Filing: POGO PRODUCING CO - Form 10-K

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

Edgar Filing: POGO PRODUCING CO - Form 10-K

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.

51

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.

Edgar Filing: POGO PRODUCING CO - Form 10-K

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

62

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	