

POGO PRODUCING CO
Form 10-Q
October 30, 2006

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549**

FORM 10-Q

- Quarterly report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended September 30, 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, Suite 2700
Houston, Texas**

(Address of principal executive offices)

77046-0504

(Zip Code)

(713) 297-5000

(Registrant's Telephone Number, Including Area Code)

Not Applicable

(Former Name, Former Address and Former Fiscal Year, if Changed Since Last Report)

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 whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See the definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer Accelerated filer Non-accelerated filer

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

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

Common Stock, par value \$1.00 per share: 58,389,247 shares as of October 24, 2006

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Statements of Income (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
(Expressed in millions, except per share amounts)				
Revenues:				
Oil and gas	\$ 340.6	\$ 275.4	\$ 1,052.1	\$ 803.5
Gain (loss) on sale of properties	(3.0)	(0.1)	305.3	0.2
Other	16.2	0.5	44.5	2.4
Total	353.8	275.8	1,401.9	806.1
Operating Costs and Expenses:				
Lease operating	66.5	31.3	191.9	93.5
General and administrative	39.7	23.2	98.5	60.2
Exploration	6.4	7.6	14.4	22.1
Dry hole and impairment	36.3	5.2	74.3	59.1
Depreciation, depletion and amortization	121.9	67.5	345.4	205.9
Production and other taxes	22.4	13.7	56.0	39.1
Other	11.8	(1.8)	53.9	(3.0)
Total	305.0	146.7	834.4	476.9
Operating Income	48.8	129.1	567.5	329.2
Interest:				
Charges	(41.4)	(16.9)	(105.9)	(40.9)
Income	0.4	5.5	1.5	7.7
Capitalized	21.7	2.5	56.5	7.4
Commodity derivative income (expense)	10.6	(18.7)	6.8	(18.7)
Foreign Currency Transaction Gain	(0.1)		1.0	
Income From Continuing Operations Before Taxes	40.0	101.5	527.4	284.7
Income Tax Expense	(6.7)	(39.6)	(64.7)	(109.3)
Income From Continuing Operations	33.3	61.9	462.7	175.4
Income from Discontinued Operations, net of tax		411.6		460.8
Net Income	\$ 33.3	\$ 473.5	\$ 462.7	\$ 636.2
Earnings per Common Share:				
Basic				
Income from continuing operations	\$ 0.58	\$ 1.04	\$ 8.04	\$ 2.87
Income from discontinued operations, net of tax		6.92		7.53
Net income	\$ 0.58	\$ 7.96	\$ 8.04	\$ 10.40
Diluted				
Income from continuing operations	\$ 0.58	\$ 1.03	\$ 7.97	\$ 2.84
Income from discontinued operations, net of tax		6.86		7.47
Net income	\$ 0.58	\$ 7.89	\$ 7.97	\$ 10.31
Dividends per Common Share	\$ 0.075	\$ 0.0625	\$ 0.225	\$ 0.188
and Potential Common Shares Outstanding:				
Basic	57,618	59,512	57,578	61,176
Diluted	57,863	60,033	58,047	61,726

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Balance Sheets (Unaudited)

	September 30, 2006	December 31, 2005
(Expressed in millions)		
Assets		
Current Assets:		
Cash and cash equivalents	\$ 29.1	\$ 57.7
Accounts receivable	149.2	198.8
Other receivables	35.0	19.9
Federal income tax receivable	35.9	21.7
Deferred tax asset		12.2
Inventories - product	17.2	13.2
Inventories - tubulars	27.8	19.1
Price hedge contracts	12.5	
Other	17.4	4.2
Total current assets	324.1	346.8
Property and Equipment:		
Oil and gas, on the basis of successful efforts accounting		
Proved properties	7,190.2	6,254.5
Unevaluated properties	1,125.7	872.2
Other, at cost	49.5	40.5
	8,365.4	7,167.2
Accumulated depreciation, depletion and amortization		
Oil and gas	(1,744.4)	(1,858.3)
Other	(30.6)	(24.5)
	(1,775.0)	(1,882.8)
Property and equipment, net	6,590.4	5,284.4
Other Assets:		
Other	48.9	44.5
	48.9	44.5
	\$ 6,963.4	\$ 5,675.7

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Balance Sheets (Unaudited)

	September 30, 2006	December 31, 2005
	(Expressed in millions, except share amounts)	
Liabilities and Shareholders Equity		
Current Liabilities:		
Accounts payable-operating activities	\$ 150.0	\$ 167.3
Accounts payable-investing activities	214.7	137.1
Income taxes payable	27.8	2.0
Accrued interest payable	38.8	20.2
Accrued payroll and related benefits	6.0	3.7
Price hedge contracts		52.3
Deferred income tax	7.7	
Other	14.4	12.5
Total current liabilities	459.4	395.1
Long-Term Debt	2,139.6	1,643.4
Deferred Income Tax	1,508.2	1,316.9
Asset Retirement Obligation	144.8	149.4
Other Liabilities and Deferred Credits	27.3	72.3
Total liabilities	4,279.3	3,577.1
Commitments and Contingencies		
Shareholders Equity:		
Preferred stock, \$1 par; 4,000,000 shares authorized		
Common stock, \$1 par; 200,000,000 shares authorized, 65,752,906 and 65,275,106 shares issued, respectively	65.8	65.3
Additional capital	964.7	977.9
Retained earnings	1,913.8	1,464.2
Deferred compensation		(17.5)
Accumulated other comprehensive income (loss)	101.1	(30.0)
Treasury stock (7,365,359 shares, at cost)	(361.3)	(361.3)
Total shareholders equity	2,684.1	2,098.6
	\$ 6,963.4	\$ 5,675.7

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows (Unaudited)

	Nine Months Ended September 30, 2006 2005 (Expressed in millions)	
Cash Flows from Operating Activities:		
Cash received from customers	\$ 1,109.9	\$ 837.0
Operating, exploration, and general and administrative expenses paid	(463.1)	(214.9)
Interest paid	(82.7)	(33.9)
Income taxes paid	(125.3)	(134.8)
Income tax refund	3.2	
Business interruption insurance proceeds	14.0	29.9
Other	6.3	10.9
Cash provided by continuing operations	462.3	494.2
Cash provided by discontinued operations		144.7
Net cash provided by operating activities	462.3	638.9
Cash Flows from Investing Activities:		
Capital expenditures	(584.1)	(276.4)
Purchase of corporations and property, net of cash acquired of \$1.8 million and \$36.6 million, respectively	(836.6)	(1,761.0)
Sale of current investments		122.3
Purchase of current investments		(16.8)
Sale of properties and corporations	449.2	777.7
Other	11.4	13.4
Cash used in continuing operations	(960.1)	(1,140.8)
Cash used in discontinued operations		(57.8)
Net cash used in investing activities	(960.1)	(1,198.6)
Cash Flows from Financing Activities:		
Borrowings under senior debt agreements	1,839.0	3,310.0
Payments under senior debt agreements	(1,793.0)	(3,324.0)
Proceeds from 2013 notes in 2006 and 2015 and 2017 notes in 2005	450.0	797.3
Purchase of Company stock	(7.7)	(235.7)
Payments of cash dividends on common stock	(13.1)	(11.5)
Receipts from discontinued operations		138.0
Payment of debt issue costs	(11.2)	(13.7)
Proceeds from exercise of stock awards	4.3	10.7
Cash provided by continuing operations	468.3	671.1
Cash used in discontinued operations		(139.6)
Net cash provided by financing activities	468.3	531.5
Effect of exchange rate changes on cash	0.9	(0.3)
Net decrease in cash and cash equivalents	(28.6)	(28.5)
Cash and cash equivalents from continuing operations, beginning of the year	57.7	33.5
Cash and cash equivalents from discontinued operations, beginning of the year		53.0
Cash and cash equivalents at the end of the period	\$ 29.1	\$ 58.0
Reconciliation of net income to net cash provided by operating activities:		
Net income	\$ 462.7	\$ 636.2
Adjustments to reconcile net income to net cash provided by operating activities -		
Income from discontinued operations, net of tax		(460.8)
Gains from the sales of properties	(305.3)	(0.2)
Depreciation, depletion and amortization	345.4	205.9
Dry hole and impairment	74.3	59.1
Interest capitalized	(56.5)	(7.4)

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Price hedge contracts	(3.3)	2.4
Other	6.1		18.9
Deferred income taxes	(48.5)	(11.5
Change in operating assets and liabilities	(12.6)	51.6
Net cash provided by continuing operating activities	462.3		494.2
Net cash provided by discontinued operating activities			144.7
Net cash provided by operating activities	\$ 462.3		\$ 638.9

See accompanying notes to consolidated financial statements.

4

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Statements of Shareholders Equity (Unaudited)

	For the Nine Months Ended September 30,			
	2006		2005	
	Shareholders		Stockholders	
	Equity		Equity	
	Shares	Amount	Shares	Amount
	(Expressed in millions, except share amounts)			
Common Stock:				
\$1.00 par-200,000,000 shares authorized				
Balance at beginning of year	65,275,106	\$ 65.3	64,580,639	\$ 64.6
Stock option activity	121,800	0.1	350,267	0.3
Shares issued as compensation	356,000	0.4	335,500	0.3
Issued at end of period	65,752,906	65.8	65,266,406	65.2
Additional Capital:				
Balance at beginning of year		977.9		943.7
Stock options exercised proceeds		3.6		12.2
Stock based compensation-excess federal tax benefit		0.9		3.1
Stock based compensation amortization stock options		0.8		1.0
Stock based compensation restricted stock		9.2		18.4
Cumulative effect of change in accounting principle		(27.7)		
Balance at end of period		964.7		978.4
Retained Earnings:				
Balance at beginning of year		1,464.2		728.7
Net income		462.7		636.2
Dividends (\$0.225 and \$0.1875 per common share, respectively)		(13.1)		(11.5)
Balance at end of period		1,913.8		1,353.4
Accumulated Other Comprehensive Income (Loss):				
Balance at beginning of year		(30.0)		2.6
Cumulative foreign currency translation adjustment		72.6		23.3
Change in fair value of price hedge contracts		63.3		(97.0)
Reclassification adjustment for (gains) losses on price hedge contracts included in net income		(4.8)		14.9
Balance at end of period		101.1		(56.2)
Deferred Compensation				
Balance at beginning of year		(17.5)		(9.9)
Activity during the period				(9.3)
Cumulative effect of change in accounting principle		17.5		
Balance at end of period				(19.2)
Treasury Stock:				
Balance at beginning of year	(7,365,359)	(361.3)	(55,359)	(1.7)
Activity during the period			(5,310,000)	(253.4)
Balance at end of period	(7,365,359)	(361.3)	(5,365,359)	(255.1)
Common Stock Outstanding, at the End of the Period	58,387,547		59,901,047	
Total Shareholders Equity		\$ 2,684.1		\$ 2,066.5

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES**Notes to Consolidated Financial Statements (Unaudited)****(1) GENERAL INFORMATION**

The consolidated financial statements included herein have been prepared by Pogo Producing Company (the Company) without audit and include all adjustments (of a normal and recurring nature), which are, in the opinion of management, necessary for the fair presentation of interim results. The interim results are not necessarily indicative of results for the entire year. The financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Company's Annual Report on Form 10-K/A for the year ended December 31, 2005.

The Company's results for 2005 reflect its oil and gas exploration, development and production activities in the Kingdom of Thailand and in Hungary as discontinued operations. Except where noted and for pro forma earnings per share, the discussions in the following notes relate to the Company's continuing operations only.

(2) ACQUISITIONS

2006 - On May 2, 2006, the Company completed the acquisition of Latigo Petroleum, Inc. (Latigo), a privately held corporation for approximately \$764.9 million in cash, including transaction costs. The purchase price was funded using cash on hand and debt financing. As of April 1, 2006, Latigo owned approximately 100,100 net producing acres, plus approximately 304,600 net acres of undeveloped leasehold. Latigo's operations are concentrated in west Texas and the Texas Panhandle with key exploration plays in the Texas Panhandle. The Company acquired Latigo primarily to strengthen its position in domestic exploration and development properties. The following is a calculation and final allocation of purchase price to the acquired assets and liabilities based on their relative fair values:

CALCULATION OF PURCHASE PRICE (IN MILLIONS)	
Cash paid, including transaction costs	\$ 764.9
Plus fair market value of liabilities assumed:	
Deferred income taxes	205.9
Other liabilities	54.7
Total purchase price for assets acquired	\$ 1,025.5
ALLOCATION OF PURCHASE PRICE (IN MILLIONS)	
Proved oil and gas properties	\$ 846.5
Unproved oil and gas properties	157.0
Other assets	22.0
Total	\$ 1,025.5

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

2005 - On September 27, 2005, the Company completed the acquisition of Northrock Resources Ltd. (Northrock) for approximately \$1.7 billion in cash. As of September 27, 2005, Northrock owned approximately 292,000 net producing acres, plus approximately 950,000 net acres of undeveloped leasehold. Northrock's activities are

concentrated in Saskatchewan and Alberta with key exploration plays in Canada's Northwest Territories, British Columbia and the Alberta Foothills. The Company acquired Northrock primarily to strengthen its position in North American exploration and development properties. The following is a calculation and final allocation of purchase price to the acquired assets and liabilities based on their relative fair values:

6

CALCULATION OF PURCHASE PRICE (IN MILLIONS)	
Cash paid, including transaction costs	\$ 1,737.5
Plus fair market value of liabilities assumed:	
Other liabilities	100.5
Asset retirement obligation	38.8
Deferred income taxes	757.3
Total purchase price for assets acquired	\$ 2,634.1
ALLOCATION OF PURCHASE PRICE (IN MILLIONS)	
Proved oil and gas properties	\$ 1,715.8
Unproved oil and gas properties	799.0
Other assets	119.3
Total	\$ 2,634.1

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

Pro Forma Information

The following summary presents unaudited pro forma consolidated results of operations for the three and nine months ended September 30, 2006 and 2005 for the Company's continuing operations as if the acquisitions of Latigo and Northrock had each occurred as of January 1, 2005. The pro forma results are for illustrative purposes only and include adjustments in addition to the pre-acquisition historical results of Latigo and Northrock, such as increased depreciation, depletion and amortization expense resulting from the allocation of fair value to oil and gas properties acquired, increased interest expense on acquisition debt and the related tax effects of these adjustments. The unaudited pro forma information (presented in millions of dollars, except per share amounts) is not necessarily indicative of the operating results that would have occurred had the acquisitions been consummated at that date, nor are they necessarily indicative of future operating results.

Pro Forma:	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Revenues	\$ 353.8	\$ 417.5	\$ 1,443.4	\$ 1,173.8
Income from continuing operations	33.3	93.3	453.3	218.3
Earnings per share:				
Basic -	\$ 0.58	\$ 1.57	\$ 7.87	\$ 3.57
Diluted -	\$ 0.58	\$ 1.55	\$ 7.81	\$ 3.54

(3) DISCONTINUED OPERATIONS

Under SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, the Company classifies assets to be disposed of as held for sale or, if appropriate, discontinued operations when appropriate approvals by the Company's management or Board of Directors have occurred and when other criteria are met. During 2005, the Company completed the sale of the assets discussed below, which have been reported as discontinued operations in the Company's historical financial statements.

Thaipo Ltd. and B8/32 Partners Ltd.

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

Pogo Hungary Ltd.

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

7

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The summarized results of the discontinued operations were as follows (amounts expressed in millions):

Operating Results Data	Three months ended September 30, 2005	Nine months ended September 30, 2005
Revenues	\$ 38.3	\$ 252.8
Costs and expenses	(14.1) (126.5
Other income	0.8	5.0
Income before income taxes	25.0	131.3
Income taxes	(16.2) (78.4
Income before gain from discontinued operations, net of tax	8.8	52.9
Gain on sale of Thailand and Pogo Hungary, net of tax of \$9.7 million	402.8	407.9
Income from discontinued operations, net of tax	\$ 411.6	\$ 460.8

(4) EARNINGS PER SHARE -

Earnings per common share (basic earnings per share) are based on the weighted average number of shares of common stock outstanding during the periods. Earnings per share and potential common shares (diluted earnings per share) consider the effect of dilutive securities as set out below. This disclosure reflects net income from both continuing and discontinued operations. Amounts are expressed in millions, except per share amounts.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Income (numerator):				
Income from continuing operations	\$ 33.3	\$ 61.9	\$ 462.7	\$ 175.4
Income from discontinued operations, net of tax		411.6		460.8
Net Income - basic and diluted	\$ 33.3	\$ 473.5	\$ 462.7	\$ 636.2
Weighted average shares (denominator):				
Weighted average shares - basic	57.6	59.5	57.6	61.2
Dilution effect of stock options and unvested restricted stock outstanding at end of period	0.3	0.5	0.5	0.5
Weighted average shares - diluted	57.9	60.0	58.1	61.7
Earnings per share:				
Basic:				
Income from continuing operations	\$ 0.58	\$ 1.04	\$ 8.04	\$ 2.87
Income from discontinued operations		6.92		7.53
Basic earnings per share	\$ 0.58	\$ 7.96	\$ 8.04	\$ 10.40
Diluted:				
Income from continuing operations	\$ 0.58	\$ 1.03	\$ 7.97	\$ 2.84
Income from discontinued operations		6.86		7.47
Diluted earnings per share	\$ 0.58	\$ 7.89	\$ 7.97	\$ 10.31
Antidilutive securities;				
Shares assumed not issued from options to purchase common shares as the exercise prices are above the average market price for the period or the effect of the assumed exercise would be antidilutive	0.02		0.02	
Average price	\$ 48.38	\$	\$ 48.93	\$

(5) LONG-TERM DEBT

Long-term debt at September 30, 2006 and December 31, 2005, consists of the following (dollars expressed in millions):

	September 30, 2006	December 31, 2005
Senior debt -		
Bank revolving credit agreement:		
LIBOR based loans, borrowings at September 30, 2006 and December 31, 2005 at interest rates of 6.832% and 5.811%, respectively	\$ 592.0	\$ 595.0
Prime based loans, borrowings at September 30, 2006 and December 31, 2005 at interest rates of 8.25% and 7.25%, respectively	25.0	11.0
LIBOR Rate Advances, borrowings at September 30, 2006 and December 31, 2005 at interest rates of 6.663% and 5.618%, respectively	75.0	40.0
Total senior debt	692.0	646.0
Senior subordinated debt -		
8.25% Senior subordinated notes, due 2011	200.0	200.0
7.875% Senior subordinated notes, due 2013	450.0	
6.625% Senior subordinated notes, due 2015	300.0	300.0
6.875% Senior subordinated notes, due 2017	500.0	500.0
Total senior subordinated debt	1,450.0	1,000.0
Unamortized discount on 2015 Notes	(2.4) (2.6
Total debt	2,139.6	1,643.4
Amount due within one year		
Long-term debt	\$ 2,139.6	\$ 1,643.4

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 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; restricted payments; the issuance and sales of restricted subsidiary capital stock; transactions with affiliates; liens; disposition of proceeds of assets sales; non-guarantor restricted subsidiaries; dividends and other payment restrictions affecting restricted subsidiaries; and merger, consolidations and the sale of assets.

(6) INCOME TAXES

During the second quarter of 2006, the Company recognized both a deferred income tax benefit and a reduction of its deferred income tax liability in the amount of \$112.3 million related to the enactment of a 1.5% reduction in Alberta provincial tax rates, the phase-in of a 5% reduction in Saskatchewan provincial tax rates and the phase-in of a 3% reduction in Canadian federal tax rates. During the third quarter of 2006, the Company continued to benefit from the favorable impact of cross-border financing in Canada, which generated an additional deferred tax benefit of approximately \$5.7 million.

As of September 30, 2006, no deferred U.S. income tax liability has been recognized on the \$210.3 million of undistributed earnings of certain foreign subsidiaries as they have been deemed permanently invested outside the U.S., and it is not practicable to estimate the deferred tax liability related to such undistributed earnings.

(7) ASSET RETIREMENT OBLIGATION

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The Company's liability for expected future costs associated with site reclamation, facilities dismantlement, and plugging and abandonment of wells for the nine month period ended September 30, 2006 is as follows (in millions):

9

	2006
ARO as of January 1,	\$ 156.3
Revisions in estimated cash flows (a)	20.7
Liabilities incurred during the nine months ended September 30,	5.1
Liabilities settled during the nine months ended September 30,	(37.3)
Accretion expense	7.5
Balance of ARO as of September 30,	152.3
Less: current portion of ARO	(7.5)
Long-term ARO as of September 30,	\$ 144.8
(a) Related primarily to higher estimated future service costs.	

For the three months ended September 30, 2006 and 2005 the Company recognized depreciation expense related to its asset retirement cost (ARC) of \$2.1 million and \$0.7 million, respectively. For the nine months ended September 30, 2006 and 2005 the Company recognized depreciation expense related to its ARC of \$6.4 million and \$2.6 million, respectively.

(8) GAIN ON SALE OF ASSETS-

On May 31, 2006, the Company sold an undivided 50 percent interest of 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 \$449.3 million, after purchase price adjustments. The sale resulted in a pre-tax gain of \$305.4 million, which includes a \$3.0 million reduction in the third quarter of 2006 due to post-closing purchase price adjustments. This gain, along with \$0.1 million of pre-tax losses on sales of other properties, has been reflected in the caption Gain (loss) on sale of properties in the Company's results of operations.

(9) GEOGRAPHIC INFORMATION

The Company's reportable geographic information is identified below. The Company evaluates performance based on operating income (loss). Financial information by geographic region is presented below:

	2006	2005
	(Expressed in millions)	
Long-Lived Assets:		
As of September 30,		
United States	\$ 3,689.0	\$ 2,578.4
Canada	2,901.4	2,495.6
Total	\$ 6,590.4	\$ 5,074.0
Capital Expenditures:		
(including interest capitalized)		
For the nine months ended September 30,		
United States	\$ 1,492.9	\$ 305.5
Canada	284.9	2,497.5
Other		0.1
Total	\$ 1,777.8	\$ 2,803.1

	For the Three Months Ended September 30, 2006		For the Nine Months Ended September 30, 2006	
	2005		2005	
	(Expressed in millions)			
Revenues:				
United States	\$ 228.8	\$ 270.2	\$ 1,018.4	\$ 800.5
Canada	124.8	5.4	383.3	5.4
Other	0.2	0.2	0.2	0.2
Total	\$ 353.8	\$ 275.8	\$ 1,401.9	\$ 806.1
Depreciation, depletion, and amortization expense:				
United States	\$ 72.1	\$ 65.6	\$ 199.3	\$ 204.0
Canada	49.8	1.9	146.1	1.9
Total	\$ 121.9	\$ 67.5	\$ 345.4	\$ 205.9
Operating income (loss):				
United States	\$ 27.4	\$ 127.3	\$ 482.3	\$ 336.8
Canada	21.8	2.3	82.3	2.3
Other	(0.4)	(0.5)	2.9	(9.9)
Total	\$ 48.8	\$ 129.1	\$ 567.5	\$ 329.2

(10) COMMODITY DERIVATIVES AND HEDGING ACTIVITIES -

As of September 30, 2006, the Company held various derivative instruments. During 2005 and 2006, the Company entered into natural gas and crude oil option agreements referred to as "collars". Collars are designed to establish floor and ceiling prices on anticipated future natural gas and crude oil production. The Company designated 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.

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During the three and nine month periods ended September 30, 2006 the Company recognized a pre-tax gain of \$0.7 million and a pre-tax loss of \$2.5 million, respectively, related to settled contracts in its oil and gas revenues from its price hedge contracts. The Company recognized pre-tax losses of \$3.1 million in its oil and gas revenues during both the three and nine month periods ended September 30, 2005 for settled price hedge contracts. The Company recognized pre-tax gains of \$4.9 million and \$3.3 million due to ineffectiveness on hedge contracts during the three and nine month periods ended September 30, 2006, respectively. The Company recognized pre-tax losses of \$0.5 million and \$1.5 million due to ineffectiveness on hedge contracts during the three and nine month periods ended September 30, 2005, respectively. Unrealized pre-tax gains on derivative instruments of \$8.7 million (\$5.5 million after taxes), have been reflected as a component of other comprehensive income at September 30, 2006. Based on the fair market value of the hedge contracts as of September 30, 2006, the Company would reclassify additional pre-tax gains of approximately \$7.6 million (approximately \$4.8 million after taxes) from accumulated other comprehensive income (shareholders' equity) to net income during the next twelve months.

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

The estimated fair value of these contracts 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 September 30, 2006 are as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price Floor	Ceiling	Fair Value of Asset (in millions)
Natural Gas Contracts (MMBtu) (a)				
Collar Contracts:				
October 2006 - December 2006	460	\$ 5.50	\$ 8.25	\$ 0.2
October 2006 - December 2006	2,760	\$ 6.00	\$ 13.50	\$ 2.4
October 2006 - December 2006	460	\$ 6.00	\$ 13.55	\$ 0.4
October 2006 - December 2006	920	\$ 6.00	\$ 13.60	\$ 0.8
October 2006 - December 2006	2,760	\$ 6.00	\$ 14.00	\$ 2.4
October 2006 - December 2006	460	\$ 7.00	\$ 10.60	\$ 0.7
October 2006 - December 2006	460	\$ 7.00	\$ 10.62	\$ 0.7
October 2006 - December 2006	460	\$ 7.00	\$ 10.70	\$ 0.7
November 2006 - December 2006	305	\$ 5.75	\$ 8.27	\$
January 2007 - December 2007	5,475	\$ 6.00	\$ 12.00	\$ 1.0
January 2007 - December 2007	1,825	\$ 6.00	\$ 12.15	\$ 0.3
January 2007 - December 2007	9,125	\$ 6.00	\$ 12.50	\$ 2.0
January 2007 - December 2007	913	\$ 8.00	\$ 13.40	\$ 1.1
January 2007 - December 2007	2,738	\$ 8.00	\$ 13.50	\$ 3.4
January 2007 - December 2007	913	\$ 8.00	\$ 13.52	\$ 1.1
January 2007 - December 2007	913	\$ 8.00	\$ 13.65	\$ 1.1
January 2008 - December 2008	1,830	\$ 8.00	\$ 12.05	\$ 1.6
January 2008 - December 2008	2,745	\$ 8.00	\$ 12.10	\$ 2.4
January 2008 - December 2008	915	\$ 8.00	\$ 12.25	\$ 0.8

(a) MMBtu means million British Thermal Units.

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Contract Period and Type of Contract	Volume	NYMEX Contract Price Floor	Ceiling	Fair Value of Asset/(Liability) (in millions)
Crude Oil Contracts (Barrels)				
Collar Contracts:				
October 2006 - December 2006	368,000	\$ 50.00	\$ 78.00	\$ (0.1)
October 2006 - December 2006	92,000	\$ 50.00	\$ 79.00	\$
October 2006 - December 2006	368,000	\$ 50.00	\$ 81.00	\$
October 2006 - December 2006	92,000	\$ 50.00	\$ 81.04	\$
October 2006 - December 2006	460,000	\$ 50.00	\$ 82.00	\$
October 2006 - December 2006	184,000	\$ 60.00	\$ 84.00	\$ 0.2
October 2006 - December 2006	46,000	\$ 60.00	\$ 85.25	\$
January 2007 - December 2007	1,460,000	\$ 50.00	\$ 75.00	\$ (4.0)
January 2007 - December 2007	365,000	\$ 50.00	\$ 75.25	\$ (1.0)
January 2007 - December 2007	3,650,000	\$ 50.00	\$ 77.50	\$ (7.7)
January 2007 - December 2007	182,500	\$ 60.00	\$ 82.75	\$ 0.1
January 2007 - December 2007	547,500	\$ 60.00	\$ 83.00	\$ 0.4
January 2007 - December 2007	182,500	\$ 60.00	\$ 84.00	\$ 0.2
January 2008 - December 2008	183,000	\$ 60.00	\$ 80.00	\$
January 2008 - December 2008	183,000	\$ 60.00	\$ 80.05	\$
January 2008 - December 2008	183,000	\$ 60.00	\$ 80.10	\$
January 2008 - December 2008	366,000	\$ 60.00	\$ 80.25	\$ (0.1)

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 under SFAS 133. For the collar contracts that no longer qualify for hedge accounting, the Company now recognizes changes in the fair value of these contracts in the consolidated statement of income for the period in which the change occurs under the caption "Commodity derivative income (expense)". The Company recognized realized and unrealized gains related to these contracts of \$10.6 million and \$6.8 million for the three and nine month periods ended September 30, 2006, respectively. As of September 30, 2006, the Company had the following open 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:				
October 2006 - December 2006	460	\$ 5.50	\$ 8.25	\$ 0.2
October 2006 - December 2006	1,380	\$ 5.00	\$ 7.50	\$
October 2006 - December 2006	615	\$ 5.75	\$ 8.27	\$ 0.5
January 2007 - December 2007	7,300	\$ 6.00	\$ 12.15	\$ 1.4
January 2007 - December 2007	3,650	\$ 6.00	\$ 12.20	\$ 0.7

(11) EMPLOYEE BENEFIT PLANS -

The Company has adopted a trustee retirement plan for its U.S. salaried employees. The benefits are based on years of service and the employee's average compensation for five consecutive years within the final ten years of service that produce the highest average compensation. The Company did not make a contribution to the plan during the first nine months of 2006; however, the Company is currently evaluating the need for a contribution during the fourth quarter of 2006.

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

The Company's net periodic benefit cost for its benefit plans is comprised of the following components (in millions of dollars):

	Retirement Plan		Nine Months Ended	
	Three Months Ended		September 30,	
	September 30,	2005	2006	2005
	2006			
Service cost	\$ 1.1	\$ 0.9	\$ 3.3	\$ 2.5
Interest cost	0.6	0.5	1.9	1.6
Expected return on plan assets	(0.7)	(0.6)	(2.1)	(1.9)
Amortization of net loss	0.5	0.2	1.4	0.9
	\$ 1.5	\$ 1.0	\$ 4.5	\$ 3.1

	Post-Retirement Medical Plan		Nine Months Ended	
	Three Months Ended		September 30,	
	September 30,	2005	2006	2005
	2006			
Service cost	\$ 0.4	\$ 0.2	\$ 1.3	\$ 1.1
Interest cost	0.3	0.1	0.9	0.8
Amortization of transition obligation		0.1		0.2
Amortization of net loss	0.1	(0.2)	0.2	
	\$ 0.8	\$ 0.2	\$ 2.4	\$ 2.1

The assumptions used in the valuation of the Company's employee benefit plans and the target investment allocations have remained the same as those disclosed in the Company's Annual Report on Form 10-K/A for the year ended December 31, 2005.

In December 2003, the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act) was signed into law. The Act introduced a prescription drug benefit under Medicare (Medicare Part D), as well as a nontaxable federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. The Company has elected not to reflect changes in the Act in its financial statements since the Company has concluded that the effects of the Act are not a significant event that calls for remeasurement under SFAS 106.

(12) ACCOUNTING FOR STOCK-BASED COMPENSATION -

The Company's incentive plans authorize awards granted wholly or partly in common stock (including rights or options which may be exercised for or settled in common stock) to key employees and non-employee directors. Awards to employees of the Company may be made as grants of stock options, stock appreciation rights, stock awards, cash awards, performance awards or any combination thereof (collectively, "Stock Awards"). Employee stock options generally become exercisable in three installments. Employee restricted stock generally becomes exercisable in four installments. The number of shares of Company common stock available for future issuance was 3,302,824 as of September 30, 2006.

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Stock options granted during and after 2003 expire 5 years from the date of grant, if not exercised. Stock options granted prior to 2003, if not exercised, expire 10 years from the date of grant.

14

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Effective January 1, 2003, the Company adopted the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, Accounting for Stock Based Compensation (SFAS 123) and the prospective method transition provisions of Statement of Financial Accounting Standards No. 148, Accounting for Stock Based Compensation Transition and Disclosure an amendment of FAS No. 123 (SFAS 148) for all Stock Awards granted, modified or settled after January 1, 2003. Under SFAS 123, the Company recognized compensation cost for all Stock Awards on either a straight-line basis over the vesting period or upon retirement, whichever was shorter (the nominal vesting period approach). On January 1, 2006, the Company adopted the provisions of SFAS No. 123 (revised 2004) (SFAS 123R), Share-Based Payment , which replaced the provisions of SFAS 123. The cumulative effect of the change in accounting principle resulting from the adoption of SFAS 123R was recognized in the Company's financial statements through the elimination of previously recognized deferred compensation costs, with offsetting amounts recorded in the additional capital account within shareholders' equity and the related deferred income tax payable. The Company adopted SFAS 123R using the modified prospective transition method. Under that transition method, compensation cost recognized during the nine months ended September 30, 2006 includes (a) compensation cost for Stock Awards granted prior to, but not yet vested as of January 1, 2006, based on the grant date fair value estimated in accordance with the original provisions of SFAS 123, and (b) compensation cost for all Stock Award grants subsequent to January 1, 2006 based on the grant date fair value estimated in accordance with SFAS 123R. Compensation cost for restricted stock and stock options is recognized using the nonsubstantive vesting period approach, i.e. (a) on a straight-line basis, over either the vesting period for the applicable Stock Award or until retirement eligibility age, whichever is shorter, or (b) over a six-month period for Stock Awards to employees who have reached retirement eligibility age. The impact of using the nonsubstantive vs. the nominal vesting period approach would have resulted in a reduction in after-tax compensation expense of \$0.6 million for both the three and nine month periods ended September 30, 2006. The impact of using the nonsubstantive vs. the nominal vesting period approach for the three and nine month periods ended September 30, 2005 would have resulted in additional after-tax compensation expense of \$1.1 million and \$1.5 million, respectively.

The following table illustrates the effect on the Company's net income and earnings per share if the fair value recognition provisions of SFAS 123R for employee stock-based compensation had been applied to all Stock Awards outstanding during the three and nine month periods ended September 30, 2005 (in millions of dollars, except per share amounts):

	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2005
Net income, as reported	\$ 473.5	\$ 636.2
Add: Employee stock-based compensation expense, net of related tax effects, included in net income, as reported	1.5	3.6
Deduct: Total employee stock-based compensation expense, determined under fair value method for all awards, net of related tax effects	(1.7)	(5.1)
Net income, pro forma	\$ 473.3	\$ 634.7
Earnings per share:		
Basic - as reported	\$ 7.96	\$ 10.40
Basic - pro forma	\$ 7.95	\$ 10.37
Diluted - as reported	\$ 7.89	\$ 10.31
Diluted - pro forma	\$ 7.88	\$ 10.28

Restricted Stock

The fair value of restricted stock grants is estimated based on the average of the high and low share price on the date of grant. A summary of the status of the Company's unvested restricted stock as of September 30, 2006 and the changes during the nine months ended September 30, 2006 is presented below:

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	Shares	Average Grant Date Fair Value
Unvested restricted stock:		
Unvested at December 31, 2005	630,600	\$ 51.57
Granted	367,800	\$ 44.47
Vested	(218,375)	\$ 48.71
Forfeited	(11,800)	\$ 48.83
Unvested at September 30, 2006	768,225	\$ 47.66

As of September 30, 2006, there was approximately \$32.9 million of total unrecognized compensation cost related to unvested restricted stock that is expected to be recognized over a weighted average period of 2.5 years. Total compensation expense for restricted stock during the three and nine month periods ended September 30, 2006 was \$4.9 million (\$3.1 million, net of tax) and \$9.8 million (\$6.2 million, net of tax), respectively. Total compensation expense for restricted stock during the three and nine month periods ended September 30, 2005 was \$2.1 million (\$1.3 million, net of tax) and \$4.6 million (\$2.9 million, net of tax), respectively. The total fair value of shares that vested and were distributed during the three and nine month periods ended September 30, 2006 was \$8.3 million and \$9.9 million, respectively, which resulted in the write-off of deferred tax assets in excess of the benefits of the tax deductions (excess tax deductions) of \$0.3 million and \$0.2 million for the same respective periods. The total fair value of shares that vested and were distributed during the three and nine month periods ended September 30, 2005 was \$6.0 million and \$6.4 million, respectively, which resulted in excess tax deductions to realize benefits of \$0.5 million in each period.

Stock Options

No stock options were granted during 2005 or in the first nine months of 2006. The fair value of previous stock option grants that either vested in 2005 or will vest in 2006 was estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used for stock option grants made in 2004 and 2003, respectively: risk free interest rates of 3.00% and 2.30%, expected volatility of 25.7% and 28.4%, dividend yields of 0.48% and 0.61%, and an expected life of the options of three and a half and three years. Total compensation expense for stock options during the three and nine months ended September 30, 2006 was \$0.1 million (\$0.1 million, net of tax) and \$0.7 million (\$0.5 million, net of tax), respectively. Total compensation expense for stock options during the three and nine months ended September 30, 2005 was \$0.4 million (\$0.2 million, net of tax) and \$1.0 million (\$0.7 million, net of tax), respectively. The total intrinsic value of stock options exercised during the three and nine months ended September 30, 2006 was \$0.2 million and \$2.5 million, resulting in excess tax deductions of \$0.1 million and \$0.9 million, respectively. The total intrinsic value of stock options exercised during the three and nine months ended September 30, 2005 was \$3.9 million and \$7.1 million, resulting in excess tax deductions of \$1.4 million and \$2.6 million, respectively. As of September 30, 2006, there was less than \$0.1 million in unrecognized compensation cost related to unvested stock options that is expected to be recognized over a weighted average period of 7 months. The Company's current practice is to issue new shares to satisfy stock option exercises. A summary of the status of the Company's stock option activity as of September 30, 2006 and changes during the nine months ended September 30, 2006 is presented below:

	Number of Awards	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (millions)(a)
Outstanding, December 31, 2005	1,782,236	\$ 29.69		
Exercised	(121,800)	\$ 30.05		
Canceled	(15,867)	\$ 43.11		
Outstanding, September 30, 2006	1,644,569	\$ 29.54	4.3 years	\$ 19.0
Exercisable, September 30, 2006	1,637,902	\$ 29.46	4.3 years	\$ 19.0

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

Restricted Stock Units

On November 1, 2005 the Company awarded 135,000 Restricted Stock Units (the Units) to certain employees of Northrock. The Units vest ratably over a three-year period. Vested Units are payable in cash in an amount equal to the fair market value of the Company's common stock for the five-day trading period ending on the vesting date. The Company recognizes compensation expense and a liability over the vesting period based on the average fair market value of Company common stock for the last five trading days of the period. For the three and nine months ended September 30, 2006, the Company recognized compensation expense of \$0.3 million and \$1.2 million, respectively, related to the Units.

(13) COMPREHENSIVE INCOME-

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Net income	\$ 33.3	\$ 473.5	\$ 462.7	\$ 636.2
Foreign currency translation adjustment, net of tax	(2.7)	23.3	72.6	23.3
Change in fair value of price hedge contracts, net of tax	44.3	(84.5)	63.3	(97.0)
Reclassification adjustment for hedge contract losses included in net income, net of tax	(10.2)	15.5	(4.8)	14.9
Comprehensive income	\$ 64.7	\$ 427.8	\$ 593.8	\$ 577.4

(14) 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. Implementation of FIN 48 is not expected to have a material financial statement impact on the Company.

On September 29, 2006 , the FASB issued Statement No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans , which amends FASB Statements No. 87, Employers Accounting for Pensions , No. 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits , No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions , and No. 132(R), Employers Disclosures About Pensions and Other Postretirement Benefits an amendment of FASB Statement Nos. 87, 88, and 106 . The Statement will require companies to recognize on their 2006 balance sheets the funded status of their pension and other postretirement benefit plans, measured as of the balance sheet date. The Statement will also require that the actuarial gains and losses and the prior service costs and credits that arise during the period be recognized, net of tax, as components of other comprehensive income; these amounts in other comprehensive income will be adjusted as they are subsequently amortized and recognized as net periodic benefit costs. The Statement is effective for publicly traded companies for fiscal years ending after December 15, 2006; the Company plans to adopt the Statement prospectively for the fiscal year ending December 31, 2006. Upon adoption of the new standard, the Company expects to reflect an additional liability of approximately \$17.9 million and a loss in accumulated other comprehensive income of approximately \$17.3 million (net of taxes of approximately \$9.9 million) in its December 31, 2006 financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

This discussion should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations included in the Company's Annual Report on Form 10-K/A for the year ended December 31, 2005 as well as the risk factors therein. The Thailand Entities and Pogo Hungary are classified as discontinued operations in the Company's financial statements for all periods presented. Except where noted, discussions in this report relate to the Company's continuing operations. However, the assets comprising the Company's continuing operations have changed substantially during the periods presented in this report, which affects comparability between those periods of the Company's results of operations and financial condition. 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, 2005, please refer to Note 2 Acquisitions to the Unaudited Consolidated Financial Statements in this report. Some of the statements in the discussion are Forward Looking Statements and are thus prospective. As further discussed in the Company's Annual Report on Form 10-K/A for the year ended December 31, 2005, these forward-looking statements are subject to risks, uncertainties and other factors that could cause actual results to differ materially from future results expressed or implied by such forward-looking statements.

Executive Overview

Below is an overview of the significant transactions and financial matters which occurred during the third quarter of 2006.

Third Quarter Results

Total revenues for the third quarter of 2006 were \$353.8 million and net income totaled \$33.3 million, or \$0.58 per share. Cash provided by operations totaled \$124.1 million. As of September 30, 2006, long-term debt was \$2,139.6 million, increasing from the second quarter by \$128.1 million due primarily to borrowings under credit arrangements used to fund tax payments related to the sale of Gulf of Mexico properties and increased drilling expenditures.

2006 Capital Budget

The Company has established an \$880 million exploration and development budget for 2006 (excluding acquisitions), including approximately \$285 million for exploration and \$595 million for development activities. The capital budget calls for the drilling of approximately 550 wells during 2006, including wells in the United States and Canada.

For the third quarter of 2006, the Company spent \$297.7 million on its exploratory and development activities and, as of September 30, 2006, had spent approximately 81% of its \$880 million 2006 capital budget. During the third quarter of 2006, 161 wells were drilled with 146 successfully completed, a 91% success rate. As of September 30, 2006, 80 wells were either drilling, completing or testing.

Recognition of Income Tax Benefit

During the third quarter 2006, the Company's consolidated effective tax rate was 16.6%. During the quarter, the company continued to benefit from the favorable impact of cross-border financing in Canada, which generated an additional deferred tax benefit of approximately \$5.7 million. Apart from the one-time benefits, the Company currently expects its annual effective tax rate to range from 28% to 33% over the next three years, based on current earnings levels and enacted tax rates.

Derivatives Hedging Income

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 \$10.6 million of realized and unrealized gains related to these contracts in the third quarter of 2006.

Planned Divestiture of Non-Core Assets

On October 18, 2006, the Company announced its intention to divest certain non-strategic oil and gas properties. The Company currently anticipates closing the first phase of the divestiture, which will include certain Gulf of Mexico, south Texas, east Texas and south Louisiana

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properties, by the end of the first quarter of 2007. The properties included in this first phase are expected to produce, in 2007, approximately 37 Mcfe per day and represent more than 90 Bcfe of proven reserves. The second phase, covering certain other properties in the Permian Basin, the Texas panhandle and in western Canada, should commence early in 2007 and be completed by mid-year. The Company plans to use the proceeds from the planned divestitures for debt reduction.

2006 Production Target

The Company's fourth quarter 2006 production volumes target, including the effects of the Latigo purchase and the Gulf of Mexico sale, is estimated to range between 85,000 - 90,000 barrels of oil equivalent per day (Boepd). The Company's 2006 target

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production yearend exit rate is estimated to range between 95,000 – 100,000 Boepd. These estimates are subject to change, and actual results could differ materially, depending upon the production levels from the Latigo purchase, 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.

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 material adverse effect on cash flow and profitability. Sustained periods of low prices could have a material adverse effect on the Company's operations and financial condition. Additionally, the cost of drilling, completing and operating wells and installing facilities and pipelines is often uncertain and have each increased substantially during 2005 and 2006. 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 the third quarter of 2006 were \$340.6 million, an increase of approximately 24% from oil and gas revenues of \$275.4 million for the third quarter of 2005. The Company's oil and gas revenues for the first nine months of 2006 were \$1,052.1 million, an increase of approximately 31% from oil and gas revenues of \$803.5 million for the first nine months of 2005. The following table reflects an analysis of variances in the Company's oil and gas revenues (expressed in millions) between 2006 and 2005.

	3rd Qtr. 2006 Compared to 3rd Qtr. 2005	1st 9 Mos. 2006 Compared to 1st 9 Mos. 2005
Increase (decrease) in oil and gas revenues resulting from variances in:		
Natural gas		
Price	\$ (43.9)	\$ (24.4)
Production	27.4	52.5
	(16.5)) 28.1
Crude oil and condensate		
Price	8.2	68.9
Production	63.5	125.8
	71.7	194.7
Natural gas liquids		
Price	4.1	8.2
Production	5.9	17.6
	10.0	25.8
Increase in oil and gas revenues	\$ 65.2	\$ 248.6

The most significant causes for the increase in hydrocarbon production were the acquisitions of Northrock on September 27, 2005 and Latigo on May 2, 2006. The increased hydrocarbon production from both of the acquisitions was partially offset by decreased production in the Company's Gulf of Mexico region resulting from sale of 50% of the Company's interest in its Gulf of Mexico properties on May 31, 2006, in addition to the curtailment of hydrocarbon production in 2006 due to the infrastructure damage caused by Hurricanes Katrina and Rita in the third quarter of 2005 and natural production declines. The following tables reflect the relative changes in hydrocarbon volumes and prices by geographic area:

			% Change			
	3rd Quarter 2006	2005	2005 to 2006	1st Nine Months 2006	2005	% Change 2005 to 2006
Comparison of Increases (Decreases) in:						
Natural Gas						

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Average prices (per Mcf)								
United States (a)	\$ 5.81	\$ 7.93	(27))%	\$ 6.29	\$ 6.74	(7))%
Canada	\$ 5.81	\$ 9.11	(b)	N/M	\$ 6.64	\$ 9.11	(b)	N/M
Company-wide average price	\$ 5.81	\$ 7.95	(27))%	\$ 6.39	\$ 6.75	(5))%
Average daily production volumes (MMcf per day) (a):								
United States	197.7	219.4	(10))%	199.3	244.1	(18))%
Canada	76.0	3.1	(b)	N/M	76.0	1.0	(b)	N/M
Company-wide average daily production	273.7	222.5	23	%	275.3	245.1	12	%

a) Price hedging activity increased the average price of the Company's United States natural gas production during the third quarter of 2006 by \$0.04 per Mcf and reduced the average price of the Company's United States natural gas production during the first nine months of 2006 by \$0.05 per Mcf. Price hedging activity reduced the average price of the Company's United States natural gas production during the third quarter and first nine months of 2005 by \$0.07 per Mcf and \$0.02 per Mcf, respectively. MMcf is an abbreviation for million cubic feet.

b) Reflects prices and production from Canada for the four day period subsequent to the Northrock acquisition on September 27, 2006. This data is shown to reflect the impact of the acquisition on the third quarter and nine months ended September 30, 2005, but is not considered meaningful for comparative purposes.

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	3rd Quarter 2006	2005	% Change 2005 to 2006	1st Nine Months 2006	2005	% Change 2005 to 2006
Comparison of Increases (Decreases) in:						
Crude Oil and Condensate						
Average prices (per Bbl)						
United States (a)	\$ 68.29	\$58.27	17%	\$64.21	\$48.56	32%
Canada	\$ 56.01	\$52.56 (b)	N/M	\$52.47	\$52.56 (b)	N/M
Company-wide average price	\$ 62.87	\$58.11	8%	\$59.20	\$48.60	22%
Average daily production volumes (Bbls per day) (a):						
United States	16,536	18,087	(9)%	18,124	23,630	(23)%
Canada	13,076	543 (b)	N/M	13,473	183 (b)	N/M
Company-wide average price	29,612	18,630	59%	31,597	23,813	33%
Natural Gas Liquids						
Average prices (per Bbl)						
United States (a)	\$ 44.89	\$33.26	35%	\$38.84	\$31.67	23%
Canada	\$ 42.31	\$49.25 (b)	N/M	\$40.31	\$49.25 (b)	N/M
Company-wide average price	\$ 44.37	\$33.73	32%	\$39.16	\$31.83	23%
Average daily production volumes (Bbls per day) (a):						
United States	4,488	4,158	8%	4,541	4,101	11%
Canada	1,158	43 (b)	N/M	1,216	15 (b)	N/M
Company-wide average daily production	5,646	4,201	34%	5,757	4,116	40%
Total Liquid Hydrocarbons						
Company-wide average daily production (Bbls per day)	35,258	22,831	54%	37,354	27,930	34%

(a) Price hedging activity had no effect on the average price of the Company's United States crude oil and condensate production during the third quarter and first nine months of 2006. Price hedging activity reduced the average price of the Company's United States crude oil and condensate production during the third quarter and first nine months of 2005 by \$1.00 per barrel and \$0.26 per barrel, respectively. Bbls is an abbreviation for barrels.

(b) Reflects prices and production from Canada for the four day period subsequent to the Northrock acquisition on September 27, 2006. This data is shown to reflect the impact of the acquisition on the third quarter and nine months ended September 30, 2005, but is not considered meaningful for comparative purposes.

Gain (Loss) on Sale of Properties

Gains (losses) on the sale of property are derived from the sale of oil and gas properties and other assets, including tubular stock and vehicles. The differences in the Company's gain (loss) on property sales in the third quarter and first nine months of 2006, compared to the same periods of 2005, are related to the recognition of a \$308.4 million gain on the sale of 50% of the Company's interests in its Gulf of Mexico properties on May 31, 2006 and the subsequent reduction of the gain in the third quarter of 2006 by \$3.0 million related to post-closing purchase price adjustments.

Other Revenues

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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 Company recognized \$12.2 million and \$39.1 million of natural gas inventory sales from the Company's Canadian operations in the third quarter and first nine months of 2006, respectively. The Company did not recognize any revenues from gas inventory sales in either the third quarter or first nine months of 2005.

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Costs and Expenses

	3rd Quarter		% Change		1st Nine Months		% Change	
	2006	2005	2005 to	2006	2006	2005	2005 to	2006
	(Expressed in millions, except DD&A statistics)							
Comparison of Increases (Decreases) in:								
Lease Operating Expenses:								
United States	\$ 45.7	\$ 30.6	49	%	\$ 132.2	\$ 92.8	42	%
Canada	\$ 20.8	\$ 0.7	N/M		\$ 59.7	\$ 0.7	N/M	
Total	\$ 66.5	\$ 31.3	112	%	\$ 191.9	\$ 93.5	105	%
General and Administrative Expenses	\$ 39.7	\$ 23.2	71	%	\$ 98.5	\$ 60.2	64	%
Exploration Expenses	\$ 6.4	\$ 7.6	(16))%	\$ 14.4	\$ 22.1	(35))%
Dry Hole and Impairment Expenses	\$ 36.3	\$ 5.2	598	%	\$ 74.3	\$ 59.1	26	%
Depreciation, Depletion and Amortization (DD&A) Expenses	\$ 121.9	\$ 67.5	81	%	\$ 345.4	\$ 205.9	68	%
DD&A rate	\$ 2.73	\$ 2.05	33	%	\$ 2.53	\$ 1.83	38	%
MMcfc produced	44,644	33,069	35	%	136,332	112,672	21	%
Production and Other Taxes	\$ 22.4	\$ 13.7	64	%	\$ 56.0	\$ 39.1	43	%
Other	\$ 11.8	\$ (1.8)	(756))%	\$ 53.9	\$ (3.0)	(1897))%
Interest								
Charges	\$ (41.4)	\$ (16.9)	145	%	\$ (105.9)	\$ (40.9)	159	%
Interest Income	\$ 0.4	\$ 5.5	(93))%	\$ 1.5	\$ 7.7	(81))%
Capitalized Interest	\$ 21.7	\$ 2.5	768	%	\$ 56.5	\$ 7.4	663	%
Commodity Derivative Income (Expense)	\$ 10.6	\$ (18.7)	(157))%	\$ 6.8	\$ (18.7)	(136))%
Income Tax Expense	\$ (6.7)	\$ (39.6)	(83))%	\$ (64.7)	\$ (109.3)	(41))%

Lease Operating Expenses

The increase in lease operating expenses for the third quarter and first nine months of 2006, compared to the third quarter and first nine months of 2005, is primarily related to the acquisitions of Northrock in late September 2005 and Latigo in May 2006, higher costs being charged by service companies in 2006 relative to the 2005 period 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.

On a per unit of production basis, the Company's total lease operating expenses have increased from an average of \$0.95 per Mcfe for the third quarter of 2005 to \$1.49 per Mcfe for the third quarter of 2006. On a per unit of production basis, the Company's total lease operating expenses have increased from an average of \$0.83 per Mcfe for the first nine months of 2005 to \$1.41 per Mcfe for the first nine months of 2006. These increases in unit costs are related to the higher oilfield service costs being charged in 2006 and hurricane related repairs, compounded by reduced offshore hydrocarbon production related to hurricane damage and natural production declines.

General and Administrative Expenses

The increase in general and administrative expenses for the third quarter and first nine months of 2006, compared with the respective 2005 periods, is related primarily to increases in the size of the Company's workforce due to the Northrock and Latigo acquisitions over the prior twelve months, increased benefit expenses and increases in compensation. On a per unit of production basis, the Company's general and administrative expenses increased to \$0.89 per Mcfe and \$0.72 per Mcfe in the third quarter and first nine months of 2006, respectively, from \$0.70 per Mcfe and \$0.53 per Mcfe in the third quarter and first nine months of 2005, respectively.

Exploration Expenses

Exploration expenses consist primarily of rental payments required under oil and gas leases to hold non-producing properties (delay rentals) and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses for the third quarter of 2006 resulted primarily from \$4.3 million of seismic activity in the Company's Canadian and Western regions and \$1.2 million of delay rentals. Exploration expenses

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for the third quarter of 2005 consisted primarily of \$6.1 million of seismic activity in the Company's Gulf Coast region and \$0.2 million of delay rentals. Exploration expenses for the first nine months of 2006 resulted primarily from \$13.8 million of seismic activity in the Company's Canadian, Gulf Coast and Western regions (offset by a \$4.7 million reimbursement of previously incurred exploration expenses in the Company's international operations by a joint venture partner) and \$4.5 million of delay rentals. Exploration expenses for the first nine months of 2005 consisted primarily of \$9.4 million from 3-D seismic activity in New Zealand, \$6.7 million of seismic activity in the Company's Gulf Coast region and \$3.5 million of seismic activity in the Company's Gulf of Mexico region, in addition to \$1.6 million of delay rentals.

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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. The increase in dry hole and impairment expense for the third quarter of 2006, compared to the third quarter of 2005, was the result of both increased dry hole costs and increased impairments. The Company incurred approximately \$23.8 million of exploratory dry hole costs during the third quarter of 2006 compared to approximately \$1.2 million incurred in the third quarter of 2005. The increase in dry hole and impairment expense for the first nine months of 2006, compared to the first nine months of 2005, was primarily the result of increased impairments discussed below, partially offset by decreased dry hole costs. The Company incurred approximately \$50.8 million of exploratory dry hole costs during the first nine months of 2006 compared to approximately \$52.3 million incurred in the first nine months of 2005. The Company had approximately \$64.6 million of costs attributable to exploratory wells in progress as of September 30, 2006 that, as of October 24, 2006 were either still in progress or pending evaluation.

Generally accepted accounting principles require that if the expected future cash flow of the Company's reserves on a property fall below the cost that is recorded on the Company's books, these properties 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 Company's 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, impairment could be required on some of the Company's properties and this impairment could have a material negative non-cash impact on the Company's earnings and balance sheet. During the third quarters of both 2006 and 2005, the Company recognized impairments on various prospects and leases in the amount of \$12.5 million and \$4.1 million, respectively. During the first nine months of both 2006 and 2005, the Company recognized impairments on various prospects and leases in the amount of \$23.5 million and \$6.8 million, respectively.

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. Generally, the Company establishes cost centers on the basis of a reasonable aggregation of properties with a common geologic structural feature or stratigraphic condition for its onshore oil and gas activities. The Company generally creates cost centers on a field-by-field basis for oil and gas activities in the Gulf of Mexico. The increase in the Company's DD&A expenses for the third quarter of 2006 compared to the third quarter of 2005 resulted primarily from an increase in the Company's equivalent hydrocarbon production and, to a lesser extent, an increase in the Company's composite DD&A rate. The increase in the Company's DD&A expenses for the first nine months of 2006 compared to the first nine months of 2005 resulted primarily from an increase in the Company's composite DD&A rate and, to a lesser extent, an increase in the Company's equivalent hydrocarbon production.

The increase in the composite DD&A rate for all of the Company's producing fields for the third quarter and first nine months of 2006, compared to the corresponding 2005 periods, 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 over the remainder of 2006, 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.

Production and Other Taxes

The increase in production and other taxes during the third quarter and first nine months of 2006, compared to the corresponding 2005 periods, relates primarily to increased severance, property and franchise taxes resulting from the increased production from the Company's domestic onshore and Canadian properties.

Other

Other expense includes the Company's cost to move its products to market (transportation costs), accretion expense related to Company asset retirement obligations under generally accepted accounting principles, natural gas purchase costs, recognition of recoveries from business interruption insurance and various other operating expenses. The following table shows the significant items included in Other expense and the changes between periods (expressed in millions):

	For the Quarter Ended		For the Nine Months	
	September 30, 2006	2005	Ended September 30, 2006	2005
Gas inventory purchases	\$ 11.9	\$	\$ 38.4	\$
Business interruption insurance	(5.5)	(7.4)	(9.2)	(18.8)

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Transportation costs	4.2	3.3	14.4	9.2
Accretion expense	2.3	1.6	7.4	4.3
Other	(1.1)	0.7	2.9	2.3
Total	\$ 11.8	\$ (1.8)	\$ 53.9	\$ (3.0)

22

Gas inventory purchases are related solely to the Company's Canadian operations which were purchased late in the third quarter of 2005 and were therefore inconsequential in either the third quarter or first nine months of 2005. The business interruption insurance relates to claims from the shut-in of a portion of the Company's Gulf of Mexico production as a result of the infrastructure damage caused by Hurricanes Ivan, Katrina and Rita. Transportation costs increased in the third quarter and first nine months of 2006 compared to the corresponding periods of 2005 due to the acquisition of Northrock in the third quarter of 2005 and Latigo in May 2006. Accretion expense increased in the third quarter and first nine months of 2006 compared to the corresponding periods of 2005 due to increased estimates of future liabilities due to rising service costs and the acquisitions of Northrock and Latigo. This increase in accretion expense was only partially offset by the sale of 50% of the Company's Gulf of Mexico interests on May 31, 2006.

Interest

Interest Charges. The increase in the Company's interest charges for the third quarter and first nine months of 2006, compared to the third quarter and first nine months of 2005, resulted primarily from an increase in the average amount of the Company's outstanding debt (incurred primarily to fund the purchase Northrock and Latigo) and, to a lesser extent, an increase in the average interest rate on the Company's revolving credit facility. See *Liquidity and Capital Resources* below.

Interest Income. The decrease in the Company's interest income for the third quarter and first nine months of 2006, compared to the third quarter and first nine months of 2005, resulted primarily from a decrease in the average amount of the Company's cash and cash equivalents on hand during the relative periods. The average amount of cash and cash equivalents on hand was unusually large during the third quarter and first nine months of 2005 due primarily to the sale of the Company's interests in its Thailand Entities and Pogo Hungary during 2005. See *Discontinued Operations* below. The average cash and cash equivalents on hand was substantially reduced late in the third quarter of 2005 with the acquisition of Northrock.

Capitalized Interest. Interest costs related to financing major oil and gas projects in progress are 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 the third quarter and first nine months of 2006, compared to the comparable 2005 periods, resulted primarily from an increase in the weighted average dollar amount of oil and gas projects in progress subject to interest capitalization during the third quarter and first nine months of 2006 (approximately \$1,152.3 million and \$1,059.9 million, respectively), compared to the third quarter and first nine months of 2005 (approximately \$177.0 million and \$174.0 million, respectively). The increase is primarily attributable to unproved property acquired in the Northrock transaction in September 2005 and the Latigo transaction in May 2006.

Commodity Derivative Income (Expense)

Commodity derivative income (expense) for the third quarter and first nine months of both 2005 and 2006 represents both realized and unrealized gains and losses on derivative contracts that no longer qualify for hedge accounting treatment. 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 under SFAS 133.

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 the third quarter and first nine months of 2006, compared to the third quarter and first nine months of 2005, primarily resulted from enacted tax rate changes in Canada during the 2006 periods. The Company's consolidated effective tax rate was 16.6% and 12.3% for the third quarter and first nine months of 2006, respectively, compared to 39.0% and 38.4% for the third quarter and first nine months of 2005. The Company currently expects its annual effective tax rate to range from 28% to 33% over the next three years, based on current earnings levels and enacted tax rates. This reduction in rates from 2005 is due to the favorable impact of cross-border financing related to the acquisition of Northrock Resources, reductions in the statutory federal income tax rates in Canada from approximately 26% to 19%, the phase-in of a deduction in Canada for Crown royalties, and the phase-in of the deduction for qualified domestic production activities in the United States.

Discontinued Operations-

The Thailand Entities (sold August 17, 2005) and Pogo Hungary (sold June 7, 2005) are classified as discontinued operations in the Company's financial statements. The summarized financial results of the discontinued operations were as follows (amounts expressed in millions):

23

POGO PRODUCING COMPANY AND SUBSIDIARIES

Operating Results Data	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2005
Revenues	\$ 38.3	\$ 252.8
Costs and expenses	(14.1) (126.5
Other income	0.8	5.0
Income before income taxes	25.0	131.3
Income taxes	(16.2) (78.4
Income before gain from discontinued operations, net of tax	8.8	52.9
Gain on sales, net of tax of \$9.7 million	402.8	407.9
Income from discontinued operations, net of tax	\$ 411.6	\$ 460.8

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 debt financing, 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 continuing operating activities for the first nine months of 2006 was \$462.3 million compared to cash flow provided by continuing operating activities of \$494.2 million in the first nine months of 2005. The decrease is attributable primarily to higher expenses, partially offset by increased production volumes and higher oil prices discussed under Results of Operations above. Cash flow from operating activities and debt financing were used during the first nine months of 2006 to fund \$641.2 million in cash expenditures for capital and exploration projects and property acquisitions. Corporate acquisitions of \$781.3 million were funded using cash on hand and debt financing. A portion of debt financing for the Latigo corporate acquisition was subsequently repaid using approximately \$449 million in cash proceeds from the Gulf of Mexico sale. During the first nine months of 2006, the Company issued \$450 million principal amount of 2013 Notes (see below) and borrowed senior debt obligations of approximately \$46 million (net of repayments). During the first nine months of 2006 the Company paid \$7.7 million for purchases of Company stock made in late December 2005 and also paid \$13.1 million of common stock dividends. As of September 30, 2006, the Company had cash and cash equivalents of \$29.1 million and long-term debt obligations of \$2.142 billion (excluding debt discount) with no repayment obligations until 2009. The Company may determine to repurchase outstanding debt in the future, including in market transactions, privately negotiated transactions or otherwise, depending on market conditions, liquidity requirements, contractual restrictions and other factors.

Effective October 20, 2006, the Company's lenders redetermined the borrowing base under its bank credit facility at \$1.5 billion. As of October 24, 2006, the Company had an outstanding balance of \$673 million under its facility and a \$1.0 billion borrowing capacity under the facility. As such, the available borrowing capacity under the facility was \$327 million.

LIBOR Rate Advances

Under separate Promissory Note Agreements dated May 8, 2004, September 13, 2004, July 17, 2006, and September 22, 2006, four of the Company's lenders make available to the Company LIBOR rate advances 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 refinance such amounts through borrowings under its bank credit facility, which is due in December 2009. 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 October 24, 2006, there was \$100 million outstanding under these agreements.

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 credit facility. 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

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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 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; restricted payments; the issuance and sales of restricted subsidiary capital stock; transactions with affiliates; liens; disposition of proceeds of assets

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sales; non-guarantor restricted subsidiaries; dividends and other payment restrictions affecting restricted subsidiaries; and merger, consolidations and the sale of assets.

Future Capital and Other Expenditure Requirements

The Company's capital and exploration budget for 2006, which does not include any amounts that may be expended for acquisitions or any interest which may be capitalized resulting from projects in progress, was increased by the Company's Board of Directors in October 2006 to \$880 million, of which approximately \$716.5 million was incurred in the nine months ended September 30, 2006. The Company has included 550 gross wells in its 2006 capital and exploration budget (370 of which were drilled in the first nine months of 2006), including wells in the United States and Canada.

The Company currently anticipates that its available cash, cash provided by operating activities and funds available under its bank credit facility will be sufficient to fund the Company's ongoing operating, interest and general and administrative expenses, capital expenditures, 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.

Planned Divestiture of Non-Core Assets

On October 18, 2006, the Company announced its intention to divest certain non-strategic oil and gas properties. The Company currently anticipates closing the first phase of the divestiture, which will include certain Gulf of Mexico, south Texas, east Texas and south Louisiana properties, by the end of the first quarter of 2007. The properties included in this first phase are expected to produce, in 2007, approximately 37 Mcfe per day and represent more than 90 Bcfe of proven reserves. The second phase, covering certain other properties in the Permian Basin, the Texas panhandle and in western Canada, should commence early in 2007 and be completed by mid-year. The Company plans to use the proceeds from the planned divestitures for debt reduction.

Share Repurchase

On January 25, 2005, the Company announced a plan to repurchase, through open market or privately negotiated transactions, not less than \$275 million nor more than \$375 million of its common stock. As of December 31, 2005, the Company had completed the purchase of 7,310,000 shares at a total cost of \$359.5 million. There were no repurchases of the Company's equity securities during the nine months ended September 30, 2006.

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. Implementation of FIN 48 is not expected to have a material financial statement impact on the Company.

On September 29, 2006, the FASB issued Statement No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, which amends FASB Statements No. 87, Employers' Accounting for Pensions, No. 88, Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits, No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, and No. 132(R), Employers' Disclosures About Pensions and Other Postretirement Benefits—an amendment of FASB Statements Nos. 87, 88, and 106. The Statement will require companies to recognize on their 2006 balance sheets the funded status of their pension and other postretirement benefit plans, measured as of the balance sheet date. The Statement will also require that the actuarial gains and losses and the prior service costs and credits that arise during the period be recognized, net of tax, as components of other comprehensive income; these amounts in other comprehensive income will be adjusted as they are subsequently amortized and recognized as net periodic benefit costs. The Statement is effective for publicly traded companies for fiscal years ending after December 15, 2006; the Company plans to adopt the Statement prospectively for the fiscal year ending December 31, 2006. Upon adoption of the new standard, the Company expects to reflect an additional liability of approximately \$17.9 million and a loss in accumulated other comprehensive income of approximately \$17.3 million (net of taxes of approximately \$9.9 million) in its December 31, 2006 financial statements.

ITEM 3.

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 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. The Company makes use of a

25

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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.

Current Hedging Activity

As of September 30, 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 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 reported settlement prices for West Texas Intermediate on the NYMEX for each trading day of a particular calendar month. For any particular collar transaction, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price for such transaction, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price of such transaction.

The estimated fair value of these contracts 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 September 30, 2006 are as follows:

Contract Period and Contract Type	Volume	NYMEX Contract Price Floor	Ceiling	Fair Value of Asset (in millions)
Natural Gas Contracts (MMBtu) (a)				
Collar Contracts:				
October 2006 - December 2006	460	\$ 5.50	\$ 8.25	\$ 0.2
October 2006 - December 2006	2,760	\$ 6.00	\$ 13.50	\$ 2.4
October 2006 - December 2006	460	\$ 6.00	\$ 13.55	\$ 0.4
October 2006 - December 2006	920	\$ 6.00	\$ 13.60	\$ 0.8
October 2006 - December 2006	2,760	\$ 6.00	\$ 14.00	\$ 2.4
October 2006 - December 2006	460	\$ 7.00	\$ 10.60	\$ 0.7
October 2006 - December 2006	460	\$ 7.00	\$ 10.62	\$ 0.7
October 2006 - December 2006	460	\$ 7.00	\$ 10.70	\$ 0.7
November 2006 - December 2006	305	\$ 5.75	\$ 8.27	\$ 0.2
January 2007 - December 2007	5,475	\$ 6.00	\$ 12.00	\$ 1.0
January 2007 - December 2007	1,825	\$ 6.00	\$ 12.15	\$ 0.3
January 2007 - December 2007	9,125	\$ 6.00	\$ 12.50	\$ 2.0
January 2007 - December 2007	913	\$ 8.00	\$ 13.40	\$ 1.1
January 2007 - December 2007	2,738	\$ 8.00	\$ 13.50	\$ 3.4
January 2007 - December 2007	913	\$ 8.00	\$ 13.52	\$ 1.1
January 2007 - December 2007	913	\$ 8.00	\$ 13.65	\$ 1.1
January 2008 - December 2008	1,830	\$ 8.00	\$ 12.05	\$ 1.6
January 2008 - December 2008	2,745	\$ 8.00	\$ 12.10	\$ 2.4
January 2008 - December 2008	915	\$ 8.00	\$ 12.25	\$ 0.8

(a) MMBtu means million British Thermal Units.

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Contract Period and Contract Type	Volume	NYMEX Contract Price Floor	Ceiling	Fair Value of Asset/(Liability) (in millions)
Crude Oil Contracts (Barrels)				
Collar Contracts:				
October 2006 December 2006	368,000	\$ 50.00	\$ 78.00	\$ (0.1)
October 2006 December 2006	92,000	\$ 50.00	\$ 79.00	\$
October 2006 December 2006	368,000	\$ 50.00	\$ 81.00	\$
October 2006 December 2006	92,000	\$ 50.00	\$ 81.04	\$
October 2006 December 2006	460,000	\$ 50.00	\$ 82.00	\$
October 2006 December 2006	184,000	\$ 60.00	\$ 84.00	\$ 0.2
October 2006 December 2006	46,000	\$ 60.00	\$ 85.25	\$
January 2007 December 2007	1,460,000	\$ 50.00	\$ 75.00	\$ (4.0)
January 2007 December 2007	365,000	\$ 50.00	\$ 75.25	\$ (1.0)
January 2007 December 2007	3,650,000	\$ 50.00	\$ 77.50	\$ (7.7)
January 2007 December 2007	182,500	\$ 60.00	\$ 82.75	\$ 0.1
January 2007 December 2007	547,500	\$ 60.00	\$ 83.00	\$ 0.4
January 2007 December 2007	182,500	\$ 60.00	\$ 84.00	\$ 0.2
January 2008 December 2008	183,000	\$ 60.00	\$ 80.00	\$
January 2008 December 2008	183,000	\$ 60.00	\$ 80.05	\$
January 2008 December 2008	183,000	\$ 60.00	\$ 80.10	\$
January 2008 December 2008	366,000	\$ 60.00	\$ 80.25	\$ (0.1)

Although the Company's collars are effective as economic hedges, the sale of 50% of the Company's Gulf of Mexico interests on May 1, 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 under SFAS 133. For the collar contracts that no longer qualify for hedge accounting, the Company now recognizes changes in the fair value of these contracts in the consolidated statement of income for the period in which the change occurs under the caption "Commodity derivative income (expense)". The Company recognized realized and unrealized gains related to these contracts of \$10.6 million and \$6.8 million for the three and nine month periods ended September 30, 2006, respectively. As of September 30, 2006, the Company had the following open collar contracts that no longer qualify for hedge accounting:

Contract Period and Contract Type	Volume	NYMEX Contract Price Floor	Ceiling	Fair Value of Asset/(Liability) (in millions)
Natural Gas Contracts (MMBtu)				
Collar Contracts:				
October 2006 December 2006	460	\$ 5.50	\$ 8.25	\$ 0.2
October 2006 December 2006	1,380	\$ 5.00	\$ 7.50	\$
October 2006 December 2006	615	\$ 5.75	\$ 8.27	\$ 0.5
January 2007 December 2007	7,300	\$ 6.00	\$ 12.15	\$ 1.4
January 2007 December 2007	3,650	\$ 6.00	\$ 12.20	\$ 0.7

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 October 24, 2006, the Company has no open interest rate swap or interest rate lock agreements. Therefore, the Company's exposure to changes in interest rates primarily results from its short-term and long-term debt with both fixed and floating interest rates. The following table presents principal or notional amounts (stated in millions) and related average interest rates by year of maturity for the Company's debt obligations and their indicated fair market value at September 30, 2006:

	2005	2006	2007	2008	2009	Thereafter	Total	Fair Value
Long-Term Debt:								
Variable Rate	\$ 0.0	\$ 0.0	\$ 0.0	\$ 0.0	\$ 692.0	\$ 0.0	\$ 692.0	\$ 692.0
Average Interest Rate					6.87	%	6.87	%
Fixed Rate	\$ 0.0	\$ 0.0	\$ 0.0	\$ 0.0	\$ 0.0	\$ 1,450.0	\$ 1,450.0	\$ 1,426.9
Average Interest Rate						7.32	% 7.32	%

Foreign Currency Exchange Rate Risk

The Company does not actively manage foreign currency risk in its foreign subsidiaries where the U.S. dollar is not the functional currency, primarily Canada, since the majority of transactions are denominated in the local currency. A substantial amount of the Company's cash is located in Canada, in Canadian dollars, which provides a natural hedge against foreign currency risk. Exposure from market rate fluctuations related to activities in New Zealand and Vietnam is not material at this time. As of October 24, 2006, the Company had no foreign currency financial derivatives.

ITEM 4. Controls and Procedures.

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

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

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

Part II. Other Information

ITEM 1A. Risk Factors.

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. Risk Factors in the Company's Annual Report on Form 10-K/A for the year ended December 31, 2005, and in Part II, Item 1A. Risk Factors in the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2006, which could materially affect the Company's business, financial condition, or future results.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds

There were no repurchases of the Company's equity securities during the nine months ended September 30, 2006.

ITEM 6. Exhibits

- *3.1 Restated Certificate of Incorporation of Pogo Producing Company, as filed on April 28, 2004 (Exhibit 3.1, Quarterly Report on Form 10-Q for the quarter ended March 31, 2004, File No. 1-7796).
- *3.2 Bylaws of Pogo Producing Company, as amended and restated through July 16, 2002 (Exhibit 4.1, Quarterly Report on Form 10-Q for the quarter ended June 30, 2002, File No. 1-7792).
- 10.1 Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Paul G. Van Wagenen, dated August 1, 2006.
- 10.2

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- Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Stephen R. Brunner, dated August 1, 2006.
- 10.3 Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Jerry A. Cooper, dated August 1, 2006.
- 10.4 Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and John O. McCoy, Jr., dated August 1, 2006.
- 10.5 Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and David R. Beathard, dated August 1, 2006.
- 10.6 Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Radford P. Laney, dated August 1, 2006.
- 10.7 Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and J. Don McGregor, dated August 1, 2006.
- 10.8 Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Gerald A. Morton, dated August 1, 2006.
- 10.9 Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and James P. Ulm, II, dated August 1, 2006.
- 10.10 Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Bruce E. Archinal, dated August 1, 2006.
- 10.11 Extension Agreement to Amended and Restated Executive Employment Agreement by and between Pogo Producing Company and Michael J. Killelea, dated August 1, 2006.
- 12.1 Statement showing computation of ratios of earnings to fixed charges.
- 31.1 Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- 31.2 Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- 32.1 Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Executive Officer.
- 32.2 Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Financial Officer.

* Asterisk indicates an exhibit incorporated by reference as shown.

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Pogo Producing Company
(Registrant)

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

/s/ Robert C. Marlowe
Robert C. Marlowe
Vice President - Accounting

Date: October 30, 2006
