POGO PRODUCING CO
Form 10-Q
July 28, 2006

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

x Quarterly report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended June 30, 2006 or

o Transition report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from to

Commission file number 1-7792

POGO PRODUCING COMPANY

(Exact Name of Registrant as Specified in Its Charter)

Delaware (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 x No o

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 x Accelerated filer o Non-accelerated filer o

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

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:	58,032,847 shares as of July 25, 2006

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Statements of Income (Unaudited)

	Three Months Ended June 30, 2006	2005	Six Months Ended June 30, 2006	2005
	(Expressed in millions, except per share amounts)			
Revenues:				
Oil and gas	$ 357.1	$ 274.0	$ 711.5	$ 528.1
Gain on sale of properties	308.3		308.3	0.3
Other	9.2	0.5	28.3	1.9
Total	674.6	274.5	1,048.1	530.3
Operating Costs and Expenses:				
Lease operating	68.3	33.5	125.4	62.2
General and administrative	30.1	18.3	58.8	37.0
Exploration	5.3	3.3	8.0	14.5
Dry hole and impairment	12.4	6.5	38.0	53.9
Depreciation, depletion and amortization	113.4	67.9	223.5	138.4
Production and other taxes	20.1	14.2	33.6	25.4
Transportation and other	16.6	4.4	42.1	(1.2)
Total	266.2	148.1	529.4	330.2
Operating Income	408.4	126.4	518.7	200.1
Interest:				
Charges	(36.2)	(13.8)	(64.5)	(24.0)
Income	0.6	1.4	1.1	2.2
Capitalized	18.6	2.7	34.8	4.9
Commodity derivative expense	(7.1)		(3.8)	
Foreign Currency Transaction Gain	1.3		1.1	
Income From Continuing Operations Before Taxes	385.6	116.7	487.4	183.2
Income Tax Expense	(23.7)	(42.7)	(58.0)	(69.7)
Income From Continuing Operations	361.9	74.0	429.4	113.5
Income from Discontinued Operations, net of tax		29.5		49.2
Net Income	$ 361.9	$ 103.5	$ 429.4	$ 162.7
Earnings per Common Share:				
Basic				
Income from continuing operations	$ 6.31	$ 1.23	$ 7.48	$ 1.83
Income from discontinued operations, net of tax		0.48		0.80
Net income	$ 6.31	$ 1.71	$ 7.48	$ 2.63
Diluted				
Income from continuing operations	$ 6.25	$ 1.22	$ 7.41	$ 1.82
Income from discontinued operations, net of tax		0.48		0.78
Net income	$ 6.25	$ 1.70	$ 7.41	$ 2.60
Dividends per Common Share	$ 0.075	$ 0.0625	$ 0.15	$ 0.125

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Balance Sheets (Unaudited)

	June 30, 2006	December 31, 2005
	(Expressed in millions)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 26.9	$ 57.7
Accounts receivable	153.0	198.8
Other receivables	28.3	19.9
Federal income tax receivable		21.7
Deferred tax asset	4.2	12.2
Inventories - product	17.4	13.2
Inventories - tubulars	26.6	19.1
Other	19.2	4.2
Total current assets	275.6	346.8
Property and Equipment:		
Oil and gas, on the basis of successful efforts accounting		
Proved properties	6,900.6	6,254.5
Unevaluated properties	1,127.7	872.2
Other, at cost	46.1	40.5
	8,074.4	7,167.2
Accumulated depreciation, depletion and amortization		
Oil and gas	(1,624.7)	(1,858.3)
Other	(28.4)	(24.5)
	(1,653.1)	(1,882.8)
Property and equipment, net	6,421.3	5,284.4
Other Assets:		
Other	49.5	44.5
	49.5	44.5
	$ 6,746.4	$ 5,675.7

See accompanying notes to consolidated financial statements.

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POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Balance Sheets (Unaudited)

	June 30, 2006	December 31, 2005
	(Expressed in millions, except share amounts)	
Liabilities and Shareholders Equity		
Current Liabilities:		
Accounts payable - operating activities	$ 159.0	$ 167.3
Accounts payable - investing activities	159.9	137.1
Income taxes payable	118.2	2.0
Accrued interest payable	21.9	20.2
Accrued payroll and related benefits	3.2	3.7
Price hedge contracts	30.9	52.3
Other	13.4	12.5
Total current liabilities	506.5	395.1
Long-Term Debt	2,011.6	1,643.4
Deferred Income Tax	1,432.9	1,316.9
Asset Retirement Obligation	124.2	149.4
Other Liabilities and Deferred Credits	52.8	72.3
Total liabilities	4,128.0	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, 65,387,706 and 65,275,106 shares issued, respectively	65.4	65.3
Additional capital	959.7	977.9
Retained earnings	1,884.9	1,464.2
Deferred compensation		(17.5)
Accumulated other comprehensive income (loss)	69.7	(30.0)
Treasury stock (7,365,359 shares, at cost)	(361.3)	(361.3)
Total shareholders equity	2,618.4	2,098.6
	$ 6,746.4	$ 5,675.7

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows (Unaudited)

	Six Months Ended June 30, 2006	2005
	(Expressed in millions)	
Cash Flows from Operating Activities:		
Cash received from customers	$ 749.5	$ 551.0
Operating, exploration, and general and administrative expenses paid	(301.8)	(143.1)
Interest paid	(59.0)	(18.6)
Income taxes paid	(60.6)	(72.1)
Income tax refund	2.6	
Other	7.5	7.5
Cash provided by continuing operations	338.2	324.7
Cash provided by discontinued operations		104.9
Net cash provided by operating activities	338.2	429.6
Cash Flows from Investing Activities:		
Capital expenditures	(369.8)	(208.0)
Purchase of corporations and property	(820.4)	(35.1)
Sale of current investments		122.3
Purchase of current investments		(16.8)
Sale of properties and corporations	463.0	7.8
Other	12.9	7.8
Cash used in continuing operations	(714.3)	(122.0)
Cash used in discontinued operations		(48.1)
Net cash used in investing activities	(714.3)	(170.1)
Cash Flows from Financing Activities:		
Borrowings under senior debt agreements	1,368.0	1,165.0
Payments under senior debt agreements	(1,450.0)	(1,337.0)
Proceeds from 2013 and 2015 Notes, respectively	450.0	297.3
Purchase of Company stock	(7.7)	(221.7)
Payments of cash dividends on common stock	(8.7)	(7.8)
Payments from discontinued operations		109.6
Payment of debt issue costs	(11.2)	(3.2)
Proceeds from exercise of stock awards	4.1	4.3
Cash provided by continuing operations	344.5	6.5
Cash used in discontinued operations		(109.6)
Net cash provided by (used in) financing activities	344.5	(103.1)
Effect of exchange rate changes on cash	0.8	(0.2)
Net increase (decrease) in cash and cash equivalents	(30.8)	156.2
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	$ 26.9	$ 242.7
Reconciliation of net income to net cash provided by operating activities:		
Net income	$ 429.4	$ 162.7
Adjustments to reconcile net income to net cash provided by operating activities -		
Income from discontinued operations, net of tax		(49.2)
Gains from the sales of properties	(308.3)	(0.3)
Depreciation, depletion and amortization	223.5	138.4
Dry hole and impairment	38.0	53.9
Interest capitalized	(34.8)	(4.9)
Price hedge contracts	1.6	1.0

Other	11.9	5.8
Deferred income taxes	(100.1)	(9.1)
Change in operating assets and liabilities	77.0	26.4
Net cash provided by continuing operating activities	338.2	324.7
Net cash provided by discontinued operating activities		104.9
Net cash provided by operating activities	$ 338.2	$ 429.6

See accompanying notes to consolidated financial statements.

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POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Statements of Shareholders Equity (Unaudited)

	For the Six Months Ended June 30, 2006 Shareholders Equity Shares	Amount	2005 Shareholders Equity 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	105,800	0.1	162,801	0.1
Shares issued as compensation	6,800		5,900	
Issued at end of period	65,387,706	65.4	64,749,340	64.7
Additional Capital:				
Balance at beginning of year		977.9		943.7
Stock options exercised - proceeds		3.0		5.8
Stock based compensation - federal tax benefit		0.8		
Stock based compensation expense - stock options		0.6		
Stock based compensation expense - restricted stock		5.1		1.0
Cumulative effect of change in accounting principle		(27.7)		
Balance at end of period		959.7		950.5
Retained Earnings:				
Balance at beginning of year		1,464.2		728.7
Net income		429.4		162.7
Dividends ($0.15 and $0.125 per common share, respectively)		(8.7)		(7.8)
Balance at end of period		1,884.9		883.6
Accumulated Other Comprehensive Income (Loss):				
Balance at beginning of year		(30.0)		2.6
Cumulative foreign currency translation adjustment		75.3		
Change in fair value of price hedge contracts		19.0		(12.1)
Reclassification adjustment for losses included in net income		5.4		(1.0)
Balance at end of period		69.7		(10.5)
Deferred Compensation				
Balance at beginning of year		(17.5)		(9.9)
Activity during the period				1.1
Cumulative effect of change in accounting principle		17.5		
Balance at end of period				(8.8)
Treasury Stock:				
Balance at beginning of year	(7,365,359)	(361.3)	(55,239)	(1.7)
Activity during the period			(4,752,900)	(221.7)
Balance at end of period	(7,365,359)	(361.3)	(4,808,139)	(223.4)
Common Stock Outstanding, at the End of the Period	58,022,347		59,941,201	
Total Shareholders Equity		$ 2,618.4		$ 1,656.1

See accompanying notes to consolidated financial statements.

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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 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 $766.4 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 preliminary 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	$ 766.4
Plus fair market value of liabilites assumed:	
Deferred income taxes	207.7
Other liabilities	55.0
Total purchase price for assets acquired	$ 1,029.1
ALLOCATION OF PURCHASE PRICE (IN MILLIONS)	
Proved oil and gas properties	$ 851.1
Unproved oil and gas properties	156.0
Other assets	22.0
Total	$ 1,029.1

The purchase price allocation noted above is subject to change based on the Company s final analysis of the assets and liabilities it has acquired, which is expected to be completed by the fourth quarter of 2006.

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 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:

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CALCULATION OF PURCHASE PRICE (IN MILLIONS)	
Cash paid, including transaction costs	$ 1,737.5
Plus fair market value of liabilites assumed:	
Other liabilites	100.5
Asset retirement obligation	38.8
Deferred income taxes	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 for these transactions.

Pro Forma Information

The following summary presents unaudited pro forma consolidated results of operations for the three and six months ended June 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 June 30,		**Six Months Ended June 30,**	
	2006	**2005**	**2006**	**2005**
Revenues	$ 653.9	$ 335.0	$ 1,019.4	$ 649.2
Income from continuing operations	339.3	55.6	394.5	91.1
Earnings per share:				
Basic -	$ 5.91	$ 0.92	$ 6.88	$ 1.47
Diluted -	$ 5.86	$ 0.91	$ 6.81	$ 1.46

(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.

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

Pogo Hungary Ltd.

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

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

Operating Results Data

	Three months ended June 30, 2005	Six months ended June 30, 2005
Revenues	$ 112.9	$ 214.5
Costs and expenses	(57.3)	(112.3)
Other income	3.5	4.1
Income before income taxes	59.1	106.3
Income taxes	(34.8)	(62.3)
Income before gain from discontinued operations, net of tax	24.3	44.0
Gain on sale of Pogo Hungary, net of tax	5.2	5.2
Income from discontinued operations, net of tax	$ 29.5	$ 49.2

(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 June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Income (numerator):				
Income from continuing operations	$ 361.9	$ 74.0	$ 429.4	$ 113.5
Income from discontinued operations, net of tax		29.5		49.2
Net Income - basic and diluted	$ 361.9	$ 103.5	$ 429.4	$ 162.7
Weighted average shares (denominator):				
Weighted average shares - basic	57.4	60.3	57.4	61.9
Dilution effect of stock options and unvested restricted stock outstanding at end of period	0.5	0.6	0.6	0.6
Weighted average shares - diluted	57.9	60.9	58.0	62.5
Earnings per share:				
Basic:				
Income from continuing operations	$ 6.31	$ 1.23	$ 7.48	$ 1.83
Income from discontinued operations		0.48		0.80
Basic earnings per share	$ 6.31	$ 1.71	$ 7.48	$ 2.63
Diluted:				
Income from continuing operations	$ 6.25	$ 1.22	$ 7.41	$ 1.82
Income from discontinued operations		0.48		0.78
Diluted earnings per share	$ 6.25	$ 1.70	$ 7.41	$ 2.60
Antidilutive securities;				
Shares assumed not issued from options to purchase common shares as the exercise prices are above the average market price for the period or the effect of the assumed exercise would be antidilutive	0.02	0.03		0.03
Average price	$ 48.93	$ 49.02	$	$ 49.02

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(5) LONG-TERM DEBT

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

	June 30, 2006	December 31, 2005
Senior debt -		
Bank revolving credit agreement:		
LIBOR based loans, borrowings at June 30, 2006 and December 31, 2005 at interest rates of 6.776% and 5.811%, respectively	$ 510.0	$ 595.0
Prime based loans, borrowings at June 30, 2006 and December 31, 2005 at interest rates of 8.25% and 7.25%, respectively	14.0	11.0
LIBOR Rate Advances, borrowings at June 30, 2006 and December 31, 2005 at interest rates of 6.485% and 5.618%, respectively	40.0	40.0
Total senior debt	564.0	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	2,011.6	1,643.4
Amount due within one year		
Long-term debt	$ 2,011.6	$ 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 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 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.

As of June 30, 2006, no deferred U.S. income tax liability has been recognized on the $188.1 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

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

	2006
ARO as of January 1,	$ 156.3
Liabilities incurred during the six months ended June 30,	5.2
Liabilities settled during the six months ended June 30,	(35.2)
Accretion expense	5.1
Balance of ARO as of June 30,	131.4
Less: current portion of ARO	(7.2)
Long-term ARO as of June 30,	$ 124.2

For the three months ended June 30, 2006 and 2005 the Company recognized depreciation expense related to its asset retirement cost (ARC) of $2.1 million and $1.0 million, respectively. For the six months ended June 30, 2006 and 2005 the Company recognized depreciation expense related to its ARC of $4.3 million and $1.9 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 $455 million, after purchase price adjustments. The sale resulted in a pre-tax gain of $308.4 million, which, along with $0.1 million of pre-tax losses on sales of other properties, have been reflected in the caption Gain 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 June 30,		
United States	$ 3,565.0	$ 2,536.1
Canada	2,856.2	
Total	$ 6,421.2	$ 2,536.1
Capital Expenditures:		
(including interest capitalized)		
For the three months ended June 30,		
United States	$ 1,283.3	$ 134.4
Canada	181.7	
Total	$ 1,465.0	$ 134.4

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2006	2005	2006	2005
	(Expressed in millions)			
Revenues:				
For the three months ended June 30,				
United States	$ 545.9	$ 274.5	$ 789.6	$ 530.3
Canada	128.7		258.5	
Total	$ 674.6	$ 274.5	$ 1,048.1	$ 530.3
Depreciation, depletion, and amortization expense:				
For the three months ended June 30,				
United States	$ 63.9	$ 67.9	$ 127.2	$ 138.4
Canada	49.5		96.3	
Total	$ 113.4	$ 67.9	$ 223.5	$ 138.4
Operating income (loss):				
For the three months ended June 30,				
United States	$ 372.8	$ 127.9	$ 454.9	$ 209.5
Canada	31.3		60.5	
Other	4.3	(1.5)	3.3	(9.4)
Total	$ 408.4	$ 126.4	$ 518.7	$ 200.1

(10) COMMODITY DERIVATIVES AND HEDGING ACTIVITIES -

As of June 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 has designated these contracts as cash flow hedges designed to achieve a more predictable cash flow, as well as to reduce its exposure to price volatility. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The use of derivatives also involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. Currently, the Company does not expect losses due to creditworthiness of its counterparties.

During the three and six month periods ended June 30, 2006 the Company recognized a pre-tax gain of $0.1 million and a pre-tax loss of $4.3 million, respectively, related to settled contracts in its oil and gas revenues from its price hedge contracts. Price hedging activity had no effect on the Company s oil and gas revenues during the three and six-month periods ended June 30, 2005. The Company recognized pre-tax losses of $1.3 million and $1.6 million due to ineffectiveness on hedge contracts during the three and six-month periods ended June 30, 2006, respectively. The Company recognized pre-tax losses of $1.0 million and $1.0 million due to ineffectiveness on hedge contracts during the three and six-month periods ended June 30, 2005, respectively. Unrealized pre-tax losses on derivative instruments of $44.9 million ($28.5 million after taxes), have been reflected as a component of other comprehensive income at June 30, 2006. Based on the fair market value of the hedge contracts as of June 30, 2006, the Company would reclassify additional pre-tax losses of approximately $24.8 million (approximately $15.7 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 reporting settlement prices for West Texas Intermediate on the NYMEX for each trading day of a particular calendar month. For any particular collar transaction, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price for such transaction, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price of such transaction.

The estimated fair value of these transactions is based upon various factors that include closing exchange prices on the NYMEX, volatility and the time value of options. Further details related to the Company s hedging activities as of June 30, 2006 are as follows:

Contract Period and Type of Contract	**Volume**	**NYMEX Contract Price Floor**	**Ceiling**	**Fair Value of Asset/(Liability) (in millions)**
Natural Gas Contracts (MMBtu) (a)				
Collar Contracts:				
September 2006	150	$ 5.00	$ 7.50	$
July 2006 - December 2006	920	$ 5.50	$ 8.25	$ (0.4)
November 2006 - December 2006	305	$ 5.75	$ 8.27	$ (0.4)
July 2006 - December 2006	5,520	$ 6.00	$ 13.50	$ 1.1
July 2006 - December 2006	920	$ 6.00	$ 13.55	$ 0.2
July 2006 - December 2006	1,840	$ 6.00	$ 13.60	$ 0.4
July 2006 - December 2006	5,520	$ 6.00	$ 14.00	$ 1.2
July 2006 - December 2006	920	$ 7.00	$ 10.60	$ 0.5
July 2006 - December 2006	920	$ 7.00	$ 10.62	$ 0.5
July 2006 - December 2006	920	$ 7.00	$ 10.70	$ 0.5
January 2007 - December 2007	5,475	$ 6.00	$ 12.00	$ (2.7)
January 2007 - December 2007	1,825	$ 6.00	$ 12.15	$ (0.8)
January 2007 - December 2007	9,125	$ 6.00	$ 12.50	$ (3.6)
January 2007 - December 2007	913	$ 8.00	$ 13.40	$ 0.4
January 2007 - December 2007	2,738	$ 8.00	$ 13.50	$ 1.1
January 2007 - December 2007	913	$ 8.00	$ 13.52	$ 0.4
January 2007 - December 2007	913	$ 8.00	$ 13.65	$ 0.4
January 2008 - December 2008	1,830	$ 8.00	$ 12.05	$ 0.5
January 2008 - December 2008	2,745	$ 8.00	$ 12.10	$ 0.8
January 2008 - December 2008	915	$ 8.00	$ 12.25	$ 0.3

(a) MMBtu means million British Thermal Units.

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:				
July 2006 - December 2006	736,000	$ 50.00	$ 78.00	$ (2.3)
July 2006 - December 2006	184,000	$ 50.00	$ 79.00	$ (0.5)
July 2006 - December 2006	736,000	$ 50.00	$ 81.00	$ (1.6)
July 2006 - December 2006	184,000	$ 50.00	$ 81.04	$ (0.4)
July 2006 - December 2006	920,000	$ 50.00	$ 82.00	$ (1.8)
July 2006 - December 2006	368,000	$ 60.00	$ 84.00	$ (0.5)
July 2006 - December 2006	92,000	$ 60.00	$ 85.25	$ (0.1)
January 2007 - December 2007	1,460,000	$ 50.00	$ 75.00	$ (10.3)
January 2007 - December 2007	365,000	$ 50.00	$ 75.25	$ (2.5)
January 2007 - December 2007	3,650,000	$ 50.00	$ 77.50	$ (22.0)
January 2007 - December 2007	182,500	$ 60.00	$ 82.75	$ (0.6)
January 2007 - December 2007	547,500	$ 60.00	$ 83.00	$ (1.7)
January 2007 - December 2007	182,500	$ 60.00	$ 84.00	$ (0.5)
January 2008 - December 2008	183,000	$ 60.00	$ 80.00	$ (0.6)
January 2008 - December 2008	183,000	$ 60.00	$ 80.05	$ (0.6)
January 2008 - December 2008	183,000	$ 60.00	$ 80.10	$ (0.6)
January 2008 - December 2008	366,000	$ 60.00	$ 80.25	$ (1.1)

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 expense. The Company recognized a $7.1 million non-cash charge related to these contracts during the second quarter of 2006. As of June 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 Liability (in millions)
Natural Gas Contracts (MMBtu)				
Collar Contracts:				
July 2006 - December 2006	920	$ 5.50	$ 8.25	$ (0.4)
July 2006 - December 2006	2,610	$ 5.00	$ 7.50	$ (2.1)
July 2006 - December 2006	1,535	$ 5.75	$ 8.27	$ (0.3)
January 2007 - December 2007	7,300	$ 6.00	$ 12.15	$ (3.3)
January 2007 - December 2007	3,650	$ 6.00	$ 12.20	$ (1.6)

(11) EMPLOYEE BENEFIT PLANS -

The Company has adopted a trusteed retirement plan for its U.S. salaried employees. The benefits are based on years of service and the employee s average compensation for five consecutive years within the final ten years of service that produce the highest average compensation. The Company did not make a contribution to the plan during the first six months of 2006 and does not expect to make a contribution during the remainder 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 Three Months Ended June 30, 2006	2005	Six Months Ended June 30, 2006	2005
Service cost	$ 1.1	$ 0.9	$ 2.2	$ 1.7
Interest cost	0.7	0.6	1.3	1.1
Expected return on plan assets	(0.7)	(0.7)	(1.4)	(1.3)
Amortization of net loss	0.4	0.3	0.9	0.6
	$ 1.5	$ 1.1	$ 3.0	$ 2.1

	Post-Retirement Medical Plan Three Months Ended June 30, 2006	2005	Six Months Ended June 30, 2006	2005
Service cost	$ 0.5	$ 0.4	$ 0.9	$ 0.8
Interest cost	0.3	0.3	0.6	0.6
Amortization of transition obligation		0.1		0.2
Amortization of net loss		0.1	0.1	0.2
	$ 0.8	$ 0.9	$ 1.6	$ 1.8

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 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 3,652,024 as of June 30, 2006. 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.

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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 six months ended June 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, stock options and other stock-based compensation 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 for the three and six month periods ended June 30, 2006 would have resulted in a reduction in after-tax compensation expense of $0.3 million and $0.1 million, respectively. The impact of using the nonsubstantive vs. the nominal vesting period approach would have resulted in a reduction of after-tax compensation expense of $0.1 million for the three month period ended June 30, 2005 and in additional after-tax compensation expense of $0.5 for the six month period ended June 30, 2005.

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 six month periods ended June 30, 2005 (in millions of dollars, except per share amounts):

	Three Months Ended June 30, 2005	**Six Months Ended June 30, 2005**
Net income, as reported	$ 103.4	$ 162.7
Add: Employee stock-based compensation expense, net of related tax effects, included in net income, as reported	1.1	2.1
Deduct: Total employee stock-based compensation expense, determined under fair value method for all awards, net of related tax effects	(1.7)	(3.3)
Net income, pro forma	$ 102.8	$ 161.5
Earnings per share:		
Basic - as reported	$ 1.71	$ 2.63
Basic - pro forma	$ 1.70	$ 2.61
Diluted - as reported	$ 1.70	$ 2.60
Diluted - pro forma	$ 1.69	$ 2.58

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 June 30, 2006 and the changes in the six months ended June 30, 2006 is presented below:

	Shares	Average Grant Date Fair Value
Unvested restricted stock:		
Unvested at December 31, 2005	630,600	$ 51.57
Granted	12,500	$ 46.23
Vested	(31,525)	$ 46.26
Forfeited	(5,700)	$ 48.26
Unvested at June 30, 2006	605,875	$ 50.03

As of June 30, 2006, there was approximately $22.3 million of total unrecognized compensation cost related to unvested restricted stock that is expected to be recognized over a weighted average period of 2.6 years. Total compensation expense for restricted stock during the three and six-month periods ended June 30, 2006 was $2.4 million ($1.6 million, net of tax) and $4.9 million ($3.1 million, net of tax), respectively. Total compensation expense for restricted stock during the three and six-month periods ended June 30, 2005 was $1.3 million ($0.8 million, net of tax) and $2.5 million ($1.6 million, net of tax), respectively. The total fair value of shares that vested and were distributed during the three and six month periods ended June 30, 2006 was $0.6 million and $1.6 million, respectively, which resulted in tax deductions to realize benefits of less than $0.1 million in each period. The total fair value of shares that vested and were distributed during the three and six month periods ended June 30, 2005 was $0.4 million and $0.4 million, respectively, which resulted in tax deductions to realize benefits of less than $0.1 million in each period.

Stock Options

No stock options were granted during 2005 or in the first six 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 six months ended June 30, 2006 was $0.4 million ($0.2 million, net of tax) and $0.6 million ($0.4 million, net of tax), respectively. Total compensation expense for stock options during the three and six months ended June 30, 2005 was $0.3 million ($0.2 million, net of tax) and $0.7 million ($0.4 million, net of tax), respectively. The total intrinsic value of stock options exercised during the three and six months ended June 30, 2006 was $0.7 million and $2.2 million, resulting in tax deductions of $0.2 million and $0.8 million, respectively. The total intrinsic value of stock options exercised during the three and six months ended June 30, 2005 was $1.3 million and $3.2 million, resulting in tax deductions of $0.5 million and $1.2 million, respectively. As of June 30, 2006, there was approximately $0.2 million in unrecognized compensation cost related to unvested stock options that is expected to be recognized over a weighted average period of 5 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 June 30, 2006 and changes during the six months ended June 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	(105,800)	$ 29.54		
Canceled	(15,867)	$ 43.11		
Outstanding, June 30, 2006	1,660,569	$ 29.58	4.5 years	$ 27.3
Exercisable, June 30, 2006	1,536,902	$ 28.55	4.9 years	$ 26.8

(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 based on the average fair market value of Company common stock for the last five trading days of the period. For the three and six months ended June 30, 2006, the Company recognized compensation expense of $0.4 million and $0.9 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 June 30,		Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
Net income	$ 361.9	$ 103.5	$ 429.4	$ 162.7
Foreign currency translation adjustment, net of tax	83.2		75.3	
Change in fair value of price hedge contracts, net of tax	(2.9)	1.7	19.0	(13.7)
Reclassification adjustment for hedge contract losses included in net income, net of tax	5.2	(0.1)	5.4	0.6
Comprehensive income	$ 447.4	$ 105.1	$ 529.1	$ 149.6

(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 derecognition, 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.

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 for the year ended December 31, 2005 as well as the risk factors therein and herein. 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. 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 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

During the second quarter of 2006, significant progress was made in the completion of the strategic initiatives the Company announced in January 2005. The Company has been transformed from a predominantly offshore property base to one where the majority of its assets are located onshore North America. During the second quarter of 2006, the Company closed both the sale of an undivided 50% of its Gulf of Mexico properties and the acquisition of Latigo Petroleum. The Company issued $450 MM of Senior Subordinated Notes during the second quarter of 2006 in order to finance a portion of the Latigo acquisition. Below is an overview of the significant transactions and financial matters which occurred during the second quarter of 2006.

Acquisition of Latigo Petroleum Inc.

On May 2, 2006, the Company completed the acquisition of Latigo Petroleum, Inc. (Latigo), a privately held exploration and production company for approximately $766.4 million. The purchase price was funded using cash on hand and debt financing. As of April 1, 2006, Latigo s estimated proven reserves were approximately 275 Bcfe located on approximately 100,100 net acres, plus approximately 304,600 net acres of undeveloped leasehold interests. Latigo s operations are concentrated in the Permian Basin and Panhandle of Texas. The Company believes that this acquisition along with its sale of 50% of its Gulf of Mexico interests discussed below further the Company s strategy to reposition itself as a predominantly onshore North American exploration and development company.

Sale of 50% of Gulf of Mexico Interests

On May 31, 2006, the Company closed the sale of an undivided 50 percent interest of each of its Gulf of Mexico oil and gas leasehold interests and related pipelines and equipment to an affiliate of Mitsui & Co., Ltd., for approximately $455 million. The proceeds were used to repay a portion of the debt used to finance the Latigo acquisition. As of December 31, 2005, the interests sold were attributed approximately 143 Bcfe of net estimated proven oil and gas reserves. The Company recognized a pre-tax gain of $308.4 million related to the sale in the second quarter of 2006.

Issuance of Senior Subordinated Notes

On June 6, 2006, the Company issued and sold $450 million aggregate principal amount of 7.875% Senior Subordinated Notes due 2013 (the 2013 Notes). The 2013 Notes were issued in a private placement pursuant to an Indenture, dated as of June 6, 2006, between the Company and The Bank of New York Trust Company, N.A., as trustee. Net proceeds were used to reduce outstanding debt under the Company s credit facility.

Second Quarter Results

Total revenues for the second quarter of 2006 were $674.6 million (including $308.4 million related to the sale of the Gulf of Mexico interests) and net income totaled $361.9 million, or $6.31 per share. Cash provided by operations totaled $338.2 million. As of June 30, 2006, long-term debt was $2,011.6 million, increasing from the first quarter by $434.1 million due primarily to the Latigo acquisition.

2006 Capital Budget

The Company has established an $800 million exploration and development budget for 2006 (excluding acquisitions), including approximately $240 million for exploration and $560 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.

During the second quarter of 2006, the Company spent $229.4 million on its exploratory and development activities and, as of June 30, 2006, had spent approximately 53% of its $800 million 2006 capital budget. During the second quarter of 2006, 102 wells were drilled with 90 successfully completed, an 88% success rate. As of June 30, 2006, 103 wells were either drilling, completing or testing.

Recognition of Income Tax Benefit

During the second quarter 2006, the Company s consolidated effective tax rate was 6.2%, down from 33.7% in the first quarter of 2006. This decrease relates to the enactment of a reduction of the Alberta and Saskatchewan provincial tax rates, in addition to a reduction in the statutory Canadian federal income tax rate, which generated a one-time deferred tax benefit of approximately $112 million. Apart from the one-time benefits, the Company currently expects its annual effective tax rate to continue to decrease over the next two years to approximately 30% - 32%, based on current earnings levels.

Derivatives Hedging Charge

Although the Company s collars are effective as economic hedges, the sale of 50% of the Company s Gulf of Mexico interests on May 31, 2006 and the forecasted shut-in hydrocarbon production from the Company s Gulf of Mexico properties (resulting primarily from hurricane activity during the third quarter of 2005) caused certain of the gas and crude oil collar contracts to lose their qualification for hedge accounting. The Company recognized a $7.1 million non-cash charge related to these contracts in the second quarter of 2006.

2006 Production Target

The Company s 2006 production volumes target, including the effects of the Latigo purchase and the Gulf of Mexico sale, is approximately 96,000 barrels of oil equivalent per day (Boepd). The Company s 2006 target production yearend exit rate is approximately 108,000 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 the first half of 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 second quarter of 2006 were $357.1 million, an increase of approximately 30% from oil and gas revenues of $274.0 million for the second quarter of 2005. The Company s oil and gas revenues for the first six months of 2006 were $711.5 million, an increase of approximately 35% from oil and gas revenues of $528.1 million for the first six 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.

	2nd Qtr. 2006 Compared to 2nd Qtr. 2005	1st 6 Mos. 2006 Compared to 1st 6 Mos. 2005
Increase (decrease) in oil and gas revenues resulting from variances in:		
Natural gas -		
Price	$ (10.5)	$ 21.2
Production	8.5	23.4
	(2.0)	44.6
Crude oil and condensate -		
Price	45.1	59.0
Production	33.0	64.0
	78.1	123.0
Natural gas liquids	7.0	15.8
Increase in oil and gas revenues	$ 83.1	$ 183.4

The most significant cause for the increase in hydrocarbon production was 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:

	2nd Quarter 2006	2005	% Change 2005 to 2006	1st Six Months 2006	2005	% Change 2005 to 2006
Comparison of Increases (Decreases) in:						
Natural Gas						
Average prices (per Mcf)						
United States (a)	**$ 5.90**	$ 6.48	**(9)%**	**$ 6.53**	$ 6.22	**5 %**
Canada	**$ 6.33**	$	**N/M**	**$ 7.05**	$	**N/M**
Company-wide average price	**$ 6.02**	$ 6.48	**(7)%**	**$ 6.68**	$ 6.22	**7 %**
Average daily production volumes (MMcf per day) (a):						
United States	**192.4**	254.5	**(24)%**	**200.0**	256.7	**(22)%**
Canada	**77.5**		**N/M**	**76.0**		**N/M**
Company-wide average daily production	**269.9**	254.5	**6 %**	**276.0**	256.7	**8 %**

(a) Price hedging activity increased the average price of the Company s United States natural gas production during the second quarter of 2006 by less than $0.01 per Mcf and reduced the average price of the Company s United States natural gas production during the first six months of 2006 by $0.09 per Mcf. Price hedging activity had no effect on the average price of the Company s United States natural gas production during the second quarter and first six months of 2005. MMcf is an abbreviation for million cubic feet.

	2nd Quarter 2006	2005	% Change 2005 to 2006	1st Six Months 2006	2005	% Change 2005 to 2006
Comparison of Increases (Decreases) in:						
Crude Oil and Condensate						
Average prices (per Bbl)						
United States (a)	**$ 70.38**	$ 46.62	**51 %**	**$ 62.39**	$ 45.19	**38 %**
Canada	**$ 58.60**	$	**N/M**	**$ 50.74**	$	**N/M**
Company-wide average price	**$ 65.47**	$ 46.62	**40 %**	**$ 57.50**	$ 45.19	**27 %**
Average daily production volumes (Bbls per day) (a):						
United States	**18,594**	26,303	**(29)%**	**18,932**	26,448	**(28)%**
Canada	**13,242**		**N/M**	**13,674**		**N/M**
Company-wide average daily production	**31,836**	26,303	**21 %**	**32,606**	26,448	**23 %**
Total Liquid Hydrocarbons						
Company-wide average daily production (Bbls per day)	**37,292**	30,450	**22 %**	**38,420**	30,521	**26 %**

(a) Price hedging activity had no effect on the average price of the Company s United States crude oil and condensate production during the second quarters and first six months of 2006 or 2005. Bbls is an abbreviation for barrels.

Gain on Sale of Properties

Gains on sale of property are derived from the sale of oil and gas properties and other assets, including tubular stock and vehicles. The increase in the Company s gain on property sales in the second quarter and first six months of 2006, compared to the same periods of 2005, is 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.

Other Revenues

Other revenue is derived from sources other than the current production of hydrocarbons. This revenue includes, among other items, natural gas inventory sales, pipeline imbalance settlements and revenue from salt-water disposal activities. The Company recognized $8.6 million and $27.0 million of natural gas inventory sales from the Company s Canadian operations in the second quarter and first six months of 2006, respectively. No gas inventory sales were made in the second quarter and first six months of 2005.

Costs and Expenses

	2nd Quarter 2006	2005	% Change 2005	1st Six Months 2006	2005	% Change 2005
	(Expressed in millions, except DD&A statistics)					
Comparison of Increases (Decreases) in:						
Lease Operating Expenses:						
United States	**$ 47.3**	$ 33.5	**41 %**	**$ 86.4**	$ 62.2	**39 %**
Canada	**$ 21.0**	$	**N/M**	**$ 39.0**	$	**N/M**
Total	**$ 68.3**	$ 33.5	**104 %**	**$ 125.4**	$ 62.2	**102 %**
General and Administrative Expenses	**$ 30.1**	$ 18.3	**64 %**	**$ 58.8**	$ 37.0	**59 %**
Exploration Expenses	**$ 5.3**	$ 3.3	**61 %**	**$ 8.0**	$ 14.5	**(45)%**
Dry Hole and Impairment Expenses	**$ 12.4**	$ 6.5	**91 %**	**$ 38.0**	$ 53.9	**(29)%**
Depreciation, Depletion and Amortization (DD&A) Expenses	**$ 113.4**	$ 67.9	**67 %**	**$ 223.5**	$ 138.4	**61 %**
DD&A rate	**$ 2.52**	$ 1.71	**47 %**	**$ 2.44**	$ 1.74	**40 %**
MMcfe produced	**44,927**	39,785	**13 %**	**91,688**	79,603	**15 %**
Production and Other Taxes	**$ 20.1**	$ 14.2	**42 %**	**$ 33.6**	$ 25.4	**32 %**
Transportation and Other	**$ 16.6**	$ 4.4	**277 %**	**$ 42.1**	$ (1.2)	**(3608)%**
Interest						
Charges	**$ (36.2)**	$ (13.8)	**162 %**	**$ (64.5)**	$ (24.0)	**169 %**
Capitalized Interest	**$ 0.6**	$ 2.7	**(78)%**	**$ 34.8**	$ 4.9	**610 %**
Commodity Derivative Income (Expense)	**$ (7.1)**	$	**N/M**	**$ (3.8)**	$	**N/M**
Income Tax Expense	**$ (23.7)**	$ (42.7)	**(44)%**	**$ 58.0**	$ (69.7)	**(183)%**

Lease Operating Expenses

The increase in lease operating expenses for the second quarter and first six months of 2006, compared to the second quarter and first six months of 2005, is primarily related to the acquisitions of Northrock in September of 2005 and Latigo in May 2006 and to higher costs being charged by service companies in 2006 relative to the 2005 period. 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 $0.84 per Mcfe for the second quarter of 2005 to $1.52 per Mcfe for the second quarter of 2006. On a per unit of production basis, the Company s total lease operating expenses have increased from an average of $0.78 per Mcfe for the first six months of 2005 to $1.37 per Mcfe for the first six months of 2006. These increases in unit costs are related to the higher oilfield service costs being charged in 2006, in addition to the Company s increased hurricane repair related operating expenses compounded by the associated reduced offshore hydrocarbon production and natural production declines.

General and Administrative Expenses

The increase in general and administrative expenses for the second quarter and first six 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 $0.67 per Mcfe and $0.64 per Mcfe in the second quarter and first six months of 2006, respectively, from $0.46 per Mcfe and $0.47 per Mcfe in the second quarter and first six 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 second quarter of 2006 resulted primarily from $6.9 million of seismic activity in the Company s Canadian and Gulf Coast regions (offset by a $4.7 million reimbursement of previously incurred exploration expenses in the Company s international operations by a new joint venture partner) and $2.2 million of delay rentals. Exploration expenses for the second quarter of 2005 consisted primarily of $1.5 million from 3-D seismic activity in New Zealand and $1.1 million of delay rentals. Exploration expenses for the first six months of 2006 resulted primarily from $8.4 million of seismic activity in the Company s Canadian and Gulf Coast 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 $3.3 million of delay rentals. Exploration expenses for the first six months of 2005 consisted primarily of $12.5 million from 3-D seismic activity in New Zealand and the Company s Gulf of Mexico regions, and $1.4 million of delay rentals.

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 second quarter of 2006, compared to the second quarter of 2005, was primarily the result of increased dry hole costs as discussed below. The decrease in dry hole and impairment expense for the first six months of 2006, compared to the first six months of 2005, was primarily the result of decreased dry hole costs, partially offset by the increased impairments discussed below. The Company incurred approximately $7.0 million of exploratory dry hole costs during the second quarter of 2006 compared to approximately $5.6 million incurred in the second quarter of 2005. The Company incurred approximately $27.0 million of exploratory dry hole costs during the first six months of 2006 compared to approximately $50.6 million incurred in the first six months of 2005. The Company had approximately $57.2 million of costs attributable to exploratory wells in progress as of June 30, 2006 that, as of July 25, 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 second quarters of both 2006 and 2005, the Company recognized miscellaneous impairments on various prospects and leases in the amount of $5.4 million and $0.9 million, respectively. During the first six months of both 2006 and 2005, the Company recognized miscellaneous impairments on various prospects and leases in the amount of $11.0 million and $3.3 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 an oil or gas trend or play for its onshore oil and gas activities. The Company generally creates cost centers on a field-by-field basis for oil and gas activities in the Gulf of Mexico. The increase in the Company s DD&A expenses for the second quarter and first six months of 2006 compared to the respective 2005 periods 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 second quarter and first six 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 Mcfe Latigo properties and the sale of the lower rate per Mcfe 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 second quarter and first six months of 2006, compared to the corresponding 2005 periods, relates primarily to increased severance, property and franchise taxes resulting from the higher product prices received by the Company and increased production from the Company s domestic onshore and Canadian properties.

Transportation and Other

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

	For the Quarter Ended June 30,		**For the Six Months Ended June 30,**	
	2006	**2005**	**2006**	**2005**
Gas inventory purchases	$ 8.6	$	$ 26.5	$

Business interruption insurance	(0.7)		(3.7)	(11.4)
Transportation costs	4.3	2.9	10.2	5.8
Accretion expense	2.5	1.4	5.1	2.7
Other	1.9	0.1	4.0	1.7
Total	$ 16.6	$ 4.4	$ 42.1	$ (1.2)

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Gas inventory purchases are related solely to the Company s Canadian operations and were therefore not present in the second quarter or first six months of 2005. The business interruption insurance relates to claims from the shut-in of a significant portion of the Company s Gulf of Mexico production as a result of the infrastructure damage caused by Hurricanes Ivan, Katrina and Rita. Transportation costs increased in the second quarter and first six 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 second quarter and first six 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, which 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 second quarter and first six months of 2006, compared to the second quarter and first six months of 2005, resulted primarily from an increase in the average amount of the Company s outstanding debt 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.

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 second quarter and first six months of 2006, compared to the comparable 2005 periods, resulted primarily from an increase in the dollar amount of oil and gas projects in progress subject to interest capitalization during the second quarter and first six months of 2006 (approximately $1,088.9 million and $1,013.7 million, respectively), compared to the second quarter and first six months of 2005 (approximately $175.8 million and $172.2 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 Expense

Commodity derivative expense for the second quarter and first six months of 2006 represents realized and unrealized 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. No such expense was incurred during the second quarter and first six months of 2005, as all of the Company s derivative contracts qualified for hedge accounting at that time.

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 tax expense for the second quarter and first six months of 2006, compared to the second quarter and first six months of 2005, primarily resulted from enacted tax rate changes in Canada during the 2006 periods. The Company s consolidated effective tax rate was 6.2% and 11.9% for the second quarter and first six months of 2006, respectively, compared to 36.6% and 38.0% for the second quarter and first six months of 2005. The Company currently expects its annual effective tax rate to continue to decrease over the next two years, based on current earnings levels. This reduction is expected due to the favorable impact of cross-border financing related to the acquisition of Northrock Resources, reductions in the statutory federal income tax rates in Canada from approximately 26% to 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):

Operating Results Data	Three Months Ended June 30, 2005	Six months Ended June 30, 2005
Revenues	$ 112.9	$ 214.5
Costs and expenses	(57.3)	(112.3)
Other income	3.5	4.1
Income before income taxes	59.1	106.3
Income taxes	(34.8)	(62.3)
Income before gain from discontinued operations, net of tax	24.3	44.0
Gain on sale of Pogo Hungary, net of tax	5.2	5.2
Income from discontinued operations, net of tax	$ 29.5	$ 49.2

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 operating activities for the first six months of 2006 was $338.2 million compared to cash flow provided by operating activities of $429.6 million in the first six months of 2005. The decrease is attributable primarily to higher expenses, partially offset by increased production volumes and higher oil and gas prices discussed under Results of Operations above. Cash flow from operating activities and debt financing were used during the first six months of 2006 to fund $407.4 million in cash expenditures for capital and exploration projects and property acquisitions. The $766.4 million Latigo acquisition was funded using cash on hand and debt financing, a portion of which was subsequently repaid using the $463.1 million in cash proceeds from the Gulf of Mexico sale. During the first six months of 2006, the Company issued $450 million principal amount of 2013 Notes (see below) and repaid senior debt obligations of approximately $82 million (net of borrowings). During the first six months of 2006 the Company paid $7.7 million for purchases of Company stock made in late December 2005 and also paid $8.7 million of common stock dividends. As of June 30, 2006, the Company had cash and cash equivalents of $26.9 million and long-term debt obligations of $2.0 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 June 6, 2006, the Company s lenders redetermined the borrowing base under its bank credit facility at $1.365 billion. As of July 25, 2006, the Company had an outstanding balance of $542 million under its facility and a $1.0 billion borrowing capacity under the facility. As such, the available borrowing capacity under the facility was $458 million.

LIBOR Rate Advances

Under separate Promissory Note Agreements dated May 8, 2004 and September 13, 2004, two of the Company s lenders make available to the Company LIBOR rate advances on an uncommitted basis up to $50 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 July 25, 2006, there was $40 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 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.

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 April 2006 to $800 million, of which approximately $422 million was incurred in the six months ended June 30, 2006. The Company has included 550 gross wells in its 2006 capital and exploration budget (209 of which were drilled in the first six 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.

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 six months ended June 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 derecognition, 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.

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 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 June 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 has designated a significant portion of these contracts as cash flow hedges designed to achieve a more predictable cash flow, as well as to reduce its exposure to price volatility. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The use of derivatives also involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. Currently, the Company does not expect losses due to creditworthiness of its counterparties.

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

POGO PRODUCING COMPANY AND SUBSIDIARIES

The estimated fair value of these transactions is based upon various factors that include closing exchange prices on the NYMEX, volatility and the time value of options. Further details related to the Company s hedging activities as of June 30, 2006 are as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price Floor	Ceiling	Fair Value of Asset/(Liability) (in millions)
Natural Gas Contracts (MMBtu) (a)				
Collar Contracts:				
September 2006	150	$ 5.00	$ 7.50	$
July 2006 - December 2006	920	$ 5.50	$ 8.25	$ (0.4)
November 2006 - December 2006	305	$ 5.75	$ 8.27	$ (0.4)
July 2006 - December 2006	5,520	$ 6.00	$ 13.50	$ 1.1
July 2006 - December 2006	920	$ 6.00	$ 13.55	$ 0.2
July 2006 - December 2006	1,840	$ 6.00	$ 13.60	$ 0.4
July 2006 - December 2006	5,520	$ 6.00	$ 14.00	$ 1.2
July 2006 - December 2006	920	$ 7.00	$ 10.60	$ 0.5
July 2006 - December 2006	920	$ 7.00	$ 10.62	$ 0.5
July 2006 - December 2006	920	$ 7.00	$ 10.70	$ 0.5
January 2007 - December 2007	5,475	$ 6.00	$ 12.00	$ (2.7)
January 2007 - December 2007	1,825	$ 6.00	$ 12.15	$ (0.8)
January 2007 - December 2007	9,125	$ 6.00	$ 12.50	$ (3.6)
January 2007 - December 2007	913	$ 8.00	$ 13.40	$ 0.4
January 2007 - December 2007	2,738	$ 8.00	$ 13.50	$ 1.1
January 2007 - December 2007	913	$ 8.00	$ 13.52	$ 0.4
January 2007 - December 2007	913	$ 8.00	$ 13.65	$ 0.4
January 2008 - December 2008	1,830	$ 8.00	$ 12.05	$ 0.5
January 2008 - December 2008	2,745	$ 8.00	$ 12.10	$ 0.8
January 2008 - December 2008	915	$ 8.00	$ 12.25	$ 0.3

(a) MMBtu means million British Thermal Units.

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:				
July 2006 - December 2006	736,000	$ 50.00	$ 78.00	$ (2.3)
July 2006 - December 2006	184,000	$ 50.00	$ 79.00	$ (0.5)
July 2006 - December 2006	736,000	$ 50.00	$ 81.00	$ (1.6)
July 2006 - December 2006	184,000	$ 50.00	$ 81.04	$ (0.4)
July 2006 - December 2006	920,000	$ 50.00	$ 82.00	$ (1.8)
July 2006 - December 2006	368,000	$ 60.00	$ 84.00	$ (0.5)
July 2006 - December 2006	92,000	$ 60.00	$ 85.25	$ (0.1)
January 2007 - December 2007	1,460,000	$ 50.00	$ 75.00	$ (10.3)
January 2007 - December 2007	365,000	$ 50.00	$ 75.25	$ (2.5)
January 2007 - December 2007	3,650,000	$ 50.00	$ 77.50	$ (22.0)
January 2007 - December 2007	182,500	$ 60.00	$ 82.75	$ (0.6)
January 2007 - December 2007	547,500	$ 60.00	$ 83.00	$ (1.7)
January 2007 - December 2007	182,500	$ 60.00	$ 84.00	$ (0.5)
January 2008 - December 2008	183,000	$ 60.00	$ 80.00	$ (0.6)
January 2008 - December 2008	183,000	$ 60.00	$ 80.05	$ (0.6)
January 2008 - December 2008	183,000	$ 60.00	$ 80.10	$ (0.6)
January 2008 - December 2008	366,000	$ 60.00	$ 80.25	$ (1.1)

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 expense. The Company recognized a $7.1 million non-cash charge related to these contracts during the second quarter of 2006. As of June 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 Liability (in millions)
Natural Gas Contracts (MMBtu)				
Collar Contracts:				
July 2006 - December 2006	920	$ 5.50	$ 8.25	$ (0.4)
July 2006 - December 2006	2,610	$ 5.00	$ 7.50	$ (2.1)
July 2006 - December 2006	1,535	$ 5.75	$ 8.27	$ (0.3)
January 2007 - December 2007	7,300	$ 6.00	$ 12.15	$ (3.3)
January 2007 - December 2007	3,650	$ 6.00	$ 12.20	$ (1.6)

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 July 25, 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 June 30, 2006:

	2005	2006	2007	2008	2009	Thereafter	Total	Fair Value
Long-Term Debt:								
Variable Rate	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 564.0	$ 0.0	$ 564.0	$ 564.0
Average Interest Rate					6.79 %		6.79 %	
Fixed Rate	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 1,450.0	$ 1,450.0	$ 1,397.4
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 July 25, 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.

Please read Risk Factors in the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2005, some of which are updated below.

The Company s recent acquisitions are significant and may not be successful.

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

- the acquired properties may not produce revenues, earnings or cash flow at anticipated levels;
- the Company may have exposure to unanticipated liabilities and costs as a result of the acquisitions, some of which may materially exceed its estimates;
- the Company may lose key employees on whom management is substantially dependent in the operation of Northrock s or Latigo s assets;
- the Company may lose customers, suppliers, partners and agents of Northrock or Latigo; and

- the Company may experience material difficulties and additional costs in integrating Northrock s or Latigo s operations, systems and personnel with its own.

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

In periods of increased drilling activity resulting from high commodity prices, demand exceeds availability for drilling rigs, drilling vessels, supply boats and personnel experienced in the oil and gas industry in general, and the offshore oil and gas industry in particular. This may lead to difficulty and delays in consistently obtaining services and equipment from vendors, obtaining drilling rigs and other equipment at favorable rates, and scheduling equipment fabrication at factories and fabrication yards. This, in turn, may lead to projects being delayed or experiencing increased costs.

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

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

The Company has substantial capital requirements.

The Company requires substantial capital to replace its reserves and generate sufficient cash flow to meet its financial obligations. If the Company cannot generate sufficient cash flow from operations or raise funds externally in the amounts and at the times needed, it may not be able to replace its reserves or meet its financial obligations. The Company recently paid approximately $1.7 billion in cash to acquire Northrock and approximately $766 million in cash to acquire Latigo. The Company s ongoing capital requirements consist primarily of the following items:

- funding its 2006 capital and exploration budget of $800 million;
- other allocations for acquisition, development, production, exploration and abandonment of oil and natural gas reserves;
- future dividends and stock repurchases.

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

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

Accordingly, these acquisitions reduce the availability of those resources for other capital requirements. Moreover, the uncertainties and risks associated with future performance and revenues will ultimately determine the Company s liquidity and ability to meet anticipated capital requirements.

The Company will continue to pursue acquisitions and dispositions.

The Company will continue to seek opportunities to generate value through business combinations, purchases and sales of assets. The Company examines potential transactions on a regular basis, depending on market conditions, available opportunities and other factors. In addition, the Company competes with other companies in pursuing acquisitions, many of which have greater financial and other resources to acquire attractive companies and properties. The successful acquisition of oil and gas properties requires an assessment of several factors, including recoverable reserves, development and exploratory potential, projected future cash flows that are, in part, based upon future oil and gas prices, current and projected operating, general and administrative and other costs, and contingent liabilities associated with the properties or entities acquired, including potential environmental and other liabilities. The accuracy of the Company s assessment of these factors is inherently uncertain, and the Company s review and assessment of potential acquisitions will not reveal all existing or potential problems nor will it permit the Company to become sufficiently familiar with the properties or entities to fully assess their deficiencies and capabilities. Even when problems are identified, the other party may be unwilling or unable to provide effective contractual protection against all or part of the problems. Furthermore, the Company may not be entitled to contractual indemnification for certain liabilities, or it may acquire the properties on an as is, where is basis.

Dispositions of portions of the Company s existing business or properties would be intended to result in the realization of immediate value but would consequently result in lower cash flows over the longer term, unless the proceeds are reinvested in more productive assets.

The Company s reserve data are estimates.

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

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

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

There were no repurchases of the Company s equity securities during the six months ended June 30, 2006.

ITEM 4. Submission of Matters to Vote of Security Holders

The registrant held its annual meeting of stockholders in Houston, Texas on April 25, 2006. Each of the individuals nominated for election as a director was elected and the proposal before the meeting was approved. The following sets forth the items that were submitted to a vote of the stockholders and the results thereof:

(A) election of three directors, each for a term of three years. The vote tabulation for each nominee was as follows:

Nominee	**For**	**Withheld**
Jerry M. Armstrong	53,330,540	309,798
Gerrit W. Gong	53,391,213	249,125
Carroll W. Suggs	53,327,392	312,946

(B) a proposal to ratify the appointment of PricewaterhouseCoopers LLP, independent accountants, to audit the financial statements of the Company for the year 2006, with 53,075,659 votes cast for ratification, 31,096 votes cast against ratification and 533,583 votes cast in absentia to the ratification.

ITEM 6. Exhibits

2.1 Agreement and Plan of Merger dated April 13, 2006 by and among Latigo Petroleum, Inc., Pogo Producing Company and Pogo Merger Sub 1, Inc. (a copy of any omitted schedule will be furnished supplementally to the Commission upon request).

2.2 Purchase and Sale Agreement dated April 20, 2006 between Pogo Producing Company and MitEnergy Upstream LLC (a copy of any omitted schedule will be furnished supplementally to the Commission upon request).

*3.1 Restated Certificate of Incorporation of Pogo Producing Company, as filed on April 28, 2004 (Exhibit 3.1, Quarterly Report on Form 10-Q for the quarter ended March 31, 2004, File No. 1-7796).

*3.2 Bylaws of Pogo Producing Company, as amended and restated through July 16, 2002 (Exhibit 4.1, Quarterly Report on Form 10-Q for the quarter ended June 30, 2002, File No. 1-7792).

*4.1 Indenture dated as of June 6, 2006 between Pogo Producing Company and the Bank of New York Trust Company N.A. (Exhibit 4.1 of the Company s Current Report on Form 8-K filed June 8, 2006, File No. 1-7792).

*4.2 Registration Rights Agreement dated as of June 6, 2006 among Pogo Producing Company and the initial purchasers named therein (Exhibit 4.2 of the Company s Current Report on Form 8-K filed June 8, 2006, File No. 1-7792).

*4.3 Senior Loan Facility dated May 2, 2006 by and among Pogo Producing Company, as the Borrower, certain Lenders party thereto from time to time and Goldman Sachs Credit Partners L.P., as the sole Lead Arranger and Book Runner, Syndication Agent, Administration Agent and Lender (Exhibit 4.1 of the Company s Current Report on Form 8-K filed May 8, 2006, File No. 1-7792).

10.1

	Purchase Agreement dated June 1, 2006, by and between Pogo Producing Company and Goldman Sachs & Co. and the other initial purchasers named therein.
10.2	Commitment Letter dated April 18, 2006, by and between Pogo Producing Company and Goldman Sachs Credit Partners L.P.
*10.3	Indemnification Agreement by and between Pogo Producing Company and Jerry M. Armstrong, dated April 25, 2006. (Exhibit 10.1, Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-7792).
*10.4	Indemnification Agreement by and between Pogo Producing Company and Robert H. Campbell, dated April 25, 2006. (Exhibit 10.2, Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-7792).
*10.5	Indemnification Agreement by and between Pogo Producing Company and William L Fisher, dated April 25, 2006. (Exhibit 10.3, Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-7792).
*10.6	Indemnification Agreement by and between Pogo Producing Company and Thomas A. Fry, III, dated April 25, 2006. (Exhibit 10.4, Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-7792).
*10.7	Indemnification Agreement by and between Pogo Producing Company and Gerrit W. Gong, dated April 25, 2006. (Exhibit 10.5, Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-7792).

*10.8	Indemnification Agreement by and between Pogo Producing Company and Charles G. Groat, dated April 25, 2006. (Exhibit 10.6, Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-7792).
*10.9	Indemnification Agreement by and between Pogo Producing Company and Carroll W. Suggs, dated April 25, 2006. (Exhibit 10.7, Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-7792).
*10.10	Indemnification Agreement by and between Pogo Producing Company and Paul G. Van Wagenen, dated April 25, 2006. (Exhibit 10.8, Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-7792).
*10.11	Indemnification Agreement by and between Pogo Producing Company and Stephen A. Wells, dated April 25, 2006. (Exhibit 10.9, Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, File No. 1-7792).
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/ Thomas E. Hart
Thomas E. Hart
Vice President and Chief
Accounting Officer

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

Date: July 28, 2006

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