POGO PRODUCING CO
Form 10-Q
October 26, 2004

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2004 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. Employee 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 requirement for the past 90 days: Yes ý No o

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2): Yes ý No o

Registrant s number of common shares outstanding as of October 20, 2004: 64,422,996

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Statements of Income (Unaudited)

	Three Months Ended September 30, 2004	Three Months Ended September 30, 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(Expressed in thousands, except per share amounts)			
Revenues:				
Oil and gas	$ 364,024	$ 278,484	$ 998,010	$ 887,347
Other	173	848	962	1,804
Total	364,197	279,332	998,972	889,151
Operating Costs and Expenses:				
Lease operating	36,334	31,268	103,559	91,811
General and administrative	18,747	16,936	52,753	45,362
Exploration	5,186	1,432	18,573	5,091
Dry hole and impairment	18,085	4,568	54,550	10,666
Depreciation, depletion and amortization	96,759	79,688	277,212	244,454
Production and other taxes	28,606	8,084	52,380	27,269
Transportation and other	5,452	5,610	15,609	21,002
Total	209,169	147,586	574,636	445,655
Operating Income	155,028	131,746	424,336	443,496
Interest:				
Charges	(6,044)	(10,255)	(22,115)	(36,934)
Income	587	446	1,482	1,380
Capitalized	3,441	4,246	11,457	12,377
Loss on Debt Extinguishment		(5,893)	(10,893)	(5,893)
Foreign Currency Transaction Gain	287	587	1,439	1,149
Income Before Taxes and Cumulative Effect of Change in Accounting Principle	153,299	120,877	405,706	415,575
Income Tax Expense	(66,687)	(53,217)	(182,265)	(175,553)
Income Before Cumulative Effect of Change in Accounting Principle	86,612	67,660	223,441	240,022
Cumulative Effect of Change in Accounting Principle				(4,166)
Net Income	$ 86,612	$ 67,660	$ 223,441	$ 235,856
Earnings Per Common Share				
Basic:				
Income before cumulative effect of change in accounting principle	$ 1.36	$ 1.07	3.50	3.86
				(0.07)

Cumulative effect of change in accounting principle								
Net income	$	1.36	$	1.07	$	3.50	$	3.79
Diluted:								
Income before cumulative effect of change in accounting principle	$	1.35	$	1.06		3.47		3.74
Cumulative effect of change in accounting principle								(0.07)
Net income	$	1.35	$	1.06	$	3.47	$	3.67
Dividends Per Common Share	$	0.05	$	0.05	$	0.15	$	0.15
Weighted Average Number of Common Shares and Potential Common Shares Outstanding:								
Basic		63,846		63,379		63,780		62,170
Diluted		64,334		63,963		64,323		64,826

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Balance Sheets (Unaudited)

	September 30, 2004	December 31, 2003
	(Expressed in thousands, except share amounts)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 170,807	$ 178,754
Accounts receivable	119,948	116,970
Other receivables	29,159	39,497
Federal income tax receivable	2,267	
Inventories - product	3,209	5,951
Inventories - tubulars	17,844	7,735
Other	8,898	5,448
Total current assets	352,132	354,355
Property and Equipment:		
Oil and gas, on the basis of successful efforts accounting		
Proved properties	4,362,646	3,919,138
Unevaluated properties	104,972	107,708
Other, at cost	33,443	30,046
	4,501,061	4,056,892
Accumulated depreciation, depletion and amortization		
Oil and gas	(1,929,937)	(1,661,584)
Other	(22,668)	(19,467)
	(1,952,605)	(1,681,051)
Property and equipment, net	2,548,456	2,375,841
Other Assets:		
Deferred income tax	2,147	2,416
Foreign value added taxes receivable	5,701	4,188
Other	24,521	25,236
	32,369	31,840
	$ 2,932,957	$ 2,762,036

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Balance Sheets (Unaudited)

	September 30, 2004	December 31, 2003
	(Expressed in thousands, except share amounts)	
Liabilities and Shareholders Equity		
Current Liabilities:		
Accounts payable - operating activities	$ 76,904	$ 55,543
Accounts payable - investing activities	61,850	73,179
Income taxes payable	11,956	20,220
Accrued interest payable	8,329	9,950
Accrued payroll and related benefits	3,566	3,242
Deferred income tax	5,324	5,324
Other	28,796	16,126
Total current liabilities	196,725	183,584
Long-Term Debt	401,000	487,261
Deferred Income Tax	533,607	546,709
Price Hedge Contracts	2,371	
Asset Retirement Obligation	93,402	70,790
Other Liabilities and Deferred Credits	22,408	20,039
Total liabilities	1,249,513	1,308,383
Commitments and Contingencies		
Shareholders Equity:		
Preferred stock, $1 par; 4,000,000 shares authorized		
Common stock, $1 par; 200,000,000 shares authorized, 64,458,688 and 63,813,283 shares issued, respectively	64,459	63,813
Additional capital	939,011	914,492
Retained earnings	694,436	480,576
Deferred compensation	(10,622)	(3,518)
Accumulated other comprehensive income (loss)	(2,130)	
Treasury stock (55,359 shares), at cost	(1,710)	(1,710)
Total shareholders equity	1,683,444	1,453,653
	$ 2,932,957	$ 2,762,036

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows (Unaudited)

	Nine Months Ended September 30, 2004	2003
	(Expressed in thousands)	
Cash Flows from Operating Activities:		
Cash received from customers	$ 1,003,583	$ 911,304
Operating, exploration, and general and administrative expenses paid	(216,301)	(167,812)
Interest paid	(22,935)	(36,373)
Income taxes paid	(198,163)	(129,612)
Value added taxes (paid)/received	(1,513)	10,172
Price hedge contracts		(14,612)
Other	8,178	6,395
Net cash provided by operating activities	572,849	579,462
Cash Flows from Investing Activities:		
Capital expenditures	(339,398)	(241,687)
Purchase of properties	(148,242)	(18,968)
Proceeds from the sale of properties	1,302	47
Net cash used in investing activities	(486,338)	(260,608)
Cash Flows from Financing Activities:		
Borrowings under senior debt agreements	945,000	417,012
Payments under senior debt agreements	(883,000)	(556,000)
Redemption of 2009 Notes	(157,782)	
Redemption of 2007 Notes		(176,578)
Payments of cash dividends on common stock	(9,581)	(9,340)
Payment of debt issue costs		(100)
Proceeds from exercise of stock options	8,623	32,677
Net cash used in financing activities	(96,740)	(292,329)
Effect of exchange rate changes on cash	2,282	627
Net (decrease) increase in cash and cash equivalents	(7,947)	27,152
Cash and cash equivalents at the beginning of the year	178,754	134,449
Cash and cash equivalents at the end of the period	$ 170,807	$ 161,601
Reconciliation of net income to net cash provided by operating activities:		
Net income	$ 223,441	$ 235,856
Adjustments to reconcile net income to net cash provided by operating activities -		
Cumulative effect of change in accounting principle		4,166
Losses from the sales of properties	76	87
Depreciation, depletion and amortization	277,212	244,454
Dry hole and impairment	54,550	10,666
Interest capitalized	(11,457)	(12,377)
Price hedge contracts	372	4,899
Other	16,878	21,054
Deferred income taxes	(5,366)	32,961
Change in operating assets and liabilities	17,143	37,696
Net cash provided by operating activities	$ 572,849	$ 579,462

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Statements of Shareholders Equity (Unaudited)

	For the Nine Months Ended September 30,					
	2004			2003		
	Shareholders Equity		Compre-hensive	Shareholders Equity		Compre-hensive
	Shares	Amount	Income	Shares	Amount	Income
	(Expressed in thousands, except share amounts)					
Common Stock:						
$ 1.00 par-200,000,000 shares authorized						
Balance at beginning of year	63,813,283	$ 63,813		61,061,888	$ 61,062	
Stock option activity and other	346,486	347		1,557,369	1,558	
Shares issued for 2006 Notes conversion				1,008,299	1,008	
Shares issued as compensation	298,919	299		170,208	170	
Issued at end of period	64,458,688	64,459		63,797,764	63,798	
Additional Capital:						
Balance at beginning of year		914,492			822,526	
Stock option activity and other		12,335			42,526	
Shares issued for 2006 Notes conversion					41,186	
Shares issued as compensation		12,184			7,035	
Balance at end of period		939,011			913,273	
Retained Earnings:						
Balance at beginning of year		480,576			202,155	
Net income		223,441	$ 223,441		235,856	$ 235,856
Dividends ($0.15 per common share)		(9,581)			(9,340)	
Balance at end of period		694,436			428,671	
Accumulated Other Comprehensive Income (Loss):						
Balance at beginning of year					(6,249)	
Change in fair value of price hedge contracts		(2,371)	(2,371)		(8,619)	(8,619)
Reclassification adjustment for losses (gains) included in net income		241	241		12,358	12,358
Balance at end of period		(2,130)			(2,510)	
Deferred Compensation						
Balance at beginning of year		(3,518)				
Activity during the period		(7,104)			(3,766)	
Balance at end of period		(10,622)			(3,766)	

Comprehensive Income (Loss)			$ 221,311			$ 239,595
Treasury Stock:						
Balance at beginning of year	(55,359)	(1,710)		(55,359)	(1,710)	
Activity during the period						
Balance at end of period	(55,359)	(1,710)		(55,359)	(1,710)	
Common Stock Outstanding, at the End of the Period	64,403,329			63,742,405		
Total Shareholders Equity		$ 1,683,444			$ 1,397,756	

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Unaudited)

(1) GENERAL INFORMATION -

The consolidated financial statements included herein have been prepared by Pogo Producing Company (the Company) without audit and include all adjustments (of a normal and recurring nature), which are, in the opinion of management, necessary for the fair presentation of interim results. The interim results are not necessarily indicative of results for the entire year. Certain prior year amounts have been reclassified to conform to current year presentation. Such reclassifications had no effect on the Company s operating income, net income or shareholders equity. 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, 2003.

(2) EARNINGS PER SHARE -

Earnings per common share (basic earnings per share) are based on the weighted average number of shares of common stock outstanding during the periods. Earnings per share and potential common shares (diluted earnings per share) consider the effect of dilutive securities as set out below. Amounts are expressed in thousands, except per share amounts.

	Three Months Ended September 30, 2004			Nine Months Ended September 30, 2004		
	Income	Shares	Per Share	Income	Shares	Per Share
Basic earnings per share -	$ 86,612	63,846	$ 1.36	$ 223,441	63,780	$ 3.50
Effect of dilutive securities:						
Options to purchase common shares		488			543	
Diluted earnings per share	$ 86,612	64,334	$ 1.35	$ 223,441	64,323	$ 3.47
Antidilutive securities -						
Options to purchase common shares		30	$ 48.50		30	$ 48.50

	Three Months Ended September 30, 2003			Nine Months Ended September 30, 2003		
	Income	Shares	Per Share	Income (a)	Shares	Per Share
Basic earnings per share -	$ 67,660	63,379	$ 1.07	$ 240,022	62,170	$ 3.86
Effect of dilutive securities:						
Options to purchase common shares		393			775	
2006 Notes (b)	68	191		2,106	1,881	
Diluted earnings per share	$ 67,728	63,963	$ 1.06	$ 242,128	64,826	$ 3.74
Antidilutive securities -						
Options to purchase common shares			$		403	$ 42.02

(a) Reflects income before cumulative effect of change in accounting principle.

(b) Redeemed on July 7, 2003.

(3) ASSET RETIREMENT OBLIGATION

The Company adopted Statement of Financial Accounting Standard (SFAS) No. 143, Accounting for Asset Retirement Obligations (SFAS 143), as of January 1, 2003. SFAS 143 requires the Company to record the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred. Upon adoption of SFAS 143, the Company was required to recognize a liability for the present value of all legal obligations associated with the retirement of tangible long-lived assets and an asset retirement cost (ARC) was capitalized as part of the carrying value of the associated asset. Upon initial application of SFAS 143, a cumulative effect of a change in accounting principle was also required in order to recognize a liability for any existing AROs adjusted for cumulative accretion, an increase to the carrying amount of the associated long-lived asset and accumulated depreciation on the capitalized cost. Subsequent to initial measurement, liabilities are required to be accreted to their present value each period and capitalized costs are depreciated over the estimated useful life of the related assets. This periodic accretion expense is recorded as Transportation and other in the consolidated statement of income. Upon settlement of the liability, the Company will settle the obligation against its recorded amount and will record any resulting gain or loss.

The Company s liability for expected future costs associated with site reclamation, facilities dismantlement, and plugging and abandonment of wells for the nine-month periods ended September 30, 2004 and 2003 is as follows (in thousands):

	2004	2003
ARO as of January 1,	$ 70,790	$ 63,643
Liabilities incurred during the nine months ended September 30,	18,392	1,908
Liabilities settled during the nine months ended September 30,	(145)	(28)
Accretion expense	4,365	3,602
Balance of ARO as of September 30,	$ 93,402	$ 69,125

For the three months ended September 30, 2004 and 2003 the Company recognized depreciation expense related to its ARO of $1,232,000 and $918,000, respectively. For the nine months ended September 30, 2004 and 2003 the Company recognized depreciation expense related to its ARO of $4,049,000 and $2,918,000, respectively. As a result of the adoption of SFAS 143 on January 1, 2003, the Company recorded a $56,769,000 increase in the net capitalized cost of its oil and gas properties and recognized an after-tax charge of $4,166,000 for the cumulative effect of the change in accounting principle.

(4) GEOGRAPHIC INFORMATION

Financial information by geographic segment is presented below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(Expressed in thousands)			
Revenues:				
United States	$ 259,711	$ 200,458	$ 745,541	$ 659,099
Kingdom of Thailand	104,457	78,874	253,395	230,029
Other	29		36	23
Total	$ 364,197	$ 279,332	$ 998,972	$ 889,151
Operating Income (Loss):				
United States	$ 113,329	$ 93,935	$ 346,202	$ 330,131
Kingdom of Thailand	44,556	38,635	112,937	115,839
Other (a)	(2,857)	(824)	(34,803)	(2,474)
Total	$ 155,028	$ 131,746	$ 424,336	$ 443,496

(a) The 2004 amounts primarily reflect dry hole and impairment costs in Hungary and the Danish North Sea.

(5) 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 nine months of 2004 and does not expect to make a contribution during the remainder of 2004.

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 thousands of dollars):

	Retirement Plan			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
Service cost	$ 719	$ 563	$ 1,973	$ 1,689
Interest cost	459	383	1,313	1,149
Expected return on plan assets	(653)	(551)	(1,979)	(1,653)
Amortization of prior service cost	10	10	34	30
Amortization of net loss	238	235	542	705
	$ 773	$ 640	$ 1,883	$ 1,920

	Post-Retirement Medical Plan			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
Service cost	$ 351	$ 293	$ 1,039	$ 879
Interest cost	241	254	783	762
Amortization of transition obligation	76	76	228	228
Amortization of net loss	31	45	143	135
	$ 699	$ 668	$ 2,193	$ 2,004

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, 2003.

In December 2003, the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Act) was signed into law. The Act introduced a prescription drug benefit under Medicare (Medicare Part D), as well as a nontaxable federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. In May 2004, the FASB issued Staff Position No. 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug Improvement and Modernization Act of 2003 (FSP No. 106-2), which addresses the accounting and disclosure requirements associated with the effects of the Act.

The Company has elected not to reflect changes in the Act in its 2004 financial statements since the Company has concluded that the effects of the Act are not a significant event that calls for remeasurement under FAS 106.

(6) 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 (collectively, Stock Awards). 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. The Company granted Stock Awards covering 293,000 shares and 329,000 shares during the three and nine-month periods ended September 30, 2004, respectively. The Company granted Stock Awards covering 537,000 shares and 547,000 shares during the three and nine-month periods ended September 30, 2003, respectively.

The following table illustrates the effect on the Company s net income and earnings per share if the fair value recognition provisions of SFAS 123 for employee stock-based compensation had been applied to all Stock Awards outstanding during the three and nine-month periods ending September 30, 2004 and 2003 (in thousands of dollars, except per share amounts):

	Three Months Ended September 30, 2004	2003	Nine Months Ended September 30, 2004	2003
Net income, as reported	$ 86,612	$ 67,660	$ 223,441	$ 235,856
Add: Employee stock-based compensation expense, net of related tax effects, included in net income, as reported	855	1,409	1,979	1,412
Deduct: Total employee stock-based compensation expense, determined under fair value method for all awards, net of related tax effects	(1,665)	(2,249)	(4,975)	(5,312)
Net income, pro forma	$ 85,802	$ 66,820	$ 220,445	$ 231,956
Earnings per share:				
Income before the cumulative effect of change in accounting principle				
Basic - as reported	$ 1.36	$ 1.07	$ 3.50	$ 3.86
Basic - pro forma	$ 1.34	$ 1.05	$ 3.46	$ 3.80
Diluted - as reported	$ 1.35	$ 1.06	$ 3.47	$ 3.74
Diluted - pro forma	$ 1.33	$ 1.05	$ 3.43	$ 3.67
Net income				
Basic - as reported	$ 1.36	$ 1.07	$ 3.50	$ 3.79
Basic - pro forma	$ 1.34	$ 1.05	$ 3.46	$ 3.73
Diluted - as reported	$ 1.35	$ 1.06	$ 3.47	$ 3.67
Diluted - pro forma	$ 1.33	$ 1.05	$ 3.43	$ 3.61

(7) HEDGING ACTIVITIES -

As of September 30, 2004, the Company held various derivative instruments. During 2004, 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-month and nine-month periods ended September 30, 2004, the Company did not recognize any gains or losses from its hedging activities related to 2004 production. The Company did recognize a pre-tax loss of $372,000 due to ineffectiveness on these hedge contracts during the third quarter and first nine months of 2004. During the three-month and nine-month periods ended September 30, 2003, the Company recognized pre-tax losses of $4,317,000 ($2,806,000 after taxes) and $19,127,000 ($12,432,000 after taxes), respectively, from its price hedge contracts, which are included in oil and gas revenues. The Company also recognized a pre-tax gain of $115,000 due to ineffectiveness on these hedge contracts during the first nine months of 2003. Net unrealized losses on derivative instruments of $2,130,000, net of deferred taxes of $1,147,000, have been reflected as a component of other comprehensive income for the nine months ended September 30, 2004. Based on the fair market value of the hedge contracts as of September 30, 2004, the Company would reclassify additional pre-tax losses of approximately $1,279,000 (approximately $831,000 after taxes) from accumulated other comprehensive loss (shareholders equity) to net income during the next twelve months.

The gas hedging transactions are generally settled based upon the average of the reporting settlement prices on the NYMEX for the last three trading days of a particular contract month. The oil hedging transactions are generally settled based on the average of the reporting settlement prices for West Texas Intermediate on the NYMEX for each trading day of a particular calendar month. For any particular collar transaction, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price for such transaction, and the Company is required to make a 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 September 30, 2004 are as follows:

Contract Period and Type of Contract	Volume		NYMEX Contract Price Floor		Ceiling		Fair Value of Asset/(Liability)
Natural Gas Contracts (MMBtu) (a)							
Collar Contracts:							
January 2005 - December 2005	5,475	$	5.50	$	8.00	$	(1,648,000)
January 2006 - December 2006	5,475	$	5.00	$	7.50	$	(2,002,000)

(a) MMBtu means million British Thermal Units.

In October 2004, the Company entered into additional natural gas and crude oil collars 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. Further details related to these hedging activities are as follows:

Contract Period and Type of Contract	Volume		NYMEX Contract Price Floor		Ceiling
Natural Gas Contracts (MMBtu)					
Collar Contracts:					
January 2005 - December 2005	1,825	$	6.00	$	9.30
January 2005 - December 2005	1,825	$	6.00	$	9.25
January 2006 - December 2006	3,650	$	5.50	$	8.25
Crude Oil Contracts (Barrels)					
Collar Contracts:					
January 2005 - December 2005	1,825,000	$	40.00	$	62.50

(8) REDEMPTION OF 2009 NOTES -

The Company gave notice on March 18, 2004 of its intent to redeem all $150,000,000 of its $10^3/_8$% Senior Subordinated Notes due 2009 (the 2009 Notes) at 105.188% of their face amount. On April 19, 2004, the Company paid $157,782,000 (excluding accrued interest) in cash to holders of the 2009 Notes. The cash redemption payment was funded through borrowings under the Company s existing bank credit facility. The Company recorded a pre-tax expense on the redemption of the 2009 Notes of $10,893,000 in the quarter ended June 30, 2004.

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, 2003. 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, 2003, 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

Total revenue for the third quarter of 2004 was $364.2 million and net income totaled $86.6 million, or $1.36 per share. Cash flow from operations totaled $224.6 million.

The Company s Board of Directors increased its capital budget from $565 million to $820 million in October 2004, one of the largest budgets in the Company s history. This budget represents an increase of more than 56% over prior year expenditures. The majority of the increase was allocated to seven acquisition transactions. The Company has closed or expects to close approximately $302 million in acquisitions for 179 bcfe of proved reserves by year-end 2004. During the third quarter of 2004, the Company spent $225 million on exploratory and developmental activities and, as of September 30, 2004, had spent 60% of its 2004 capital budget. The budget includes the drilling of 390 wells during 2004, a record number. During the third quarter of 2004, 94 wells were drilled with 88 successfully completed, a 94% success rate. For the nine months ended September 30, 2004, 248 wells had been drilled, with 64 wells that were either being drilled or completed at quarter-end.

Dividend Increase

The Company announced on October 19, 2004, a quarterly dividend of $0.0625 on its common stock, an increase of 25%. The dividend will be paid on November 19, 2004, to shareholders of record as of November 5, 2004. The increased dividend represents an annual rate of $0.25 per share.

Hurricane Ivan Update

Company operated Gulf of Mexico platforms did not sustain major damage as a result of Hurricane Ivan. However, damages to outside owned and operated platforms, pipelines and onshore terminals are continuing to cause a meaningful component of the Company s Gulf of Mexico production to remain shut-in. Beginning September 14, 2004 the Company estimates its third quarter production was reduced due to Hurricane Ivan by approximately 900 million cubic feet of natural gas and 400,000 barrels of oil. As of September 30, 2004 some 23,000 barrels of oil per day and 33 million cubic feet of natural gas per day from Main Pass, South Pass, West Delta and Viosca Knoll areas remain shut-in. Repairs to the infrastructure are underway, but the Company does not expect to restore production from most of these fields until at least the end of December. Repairs to the more heavily damaged facilities are not expected to be completed until the first quarter of 2005. In order to protect its cash flow, the Company has business interruption insurance for certain of the blocks affected by the shut-in. Coverage begins sixty days after the blocks are shut-in and will continue until the production is restored. When coverage commences, the Company expects to receive payment from its business interruption insurance policy until production is fully restored for a period of up to one year. The daily indemnity amount expected to be paid to the Company is approximately $600,000 per day for the Main Pass 61/62 Blocks and approximately $50,000 per day for other blocks affected by the shut-in. These amounts could be reduced from cash flow from partially restored production.

Exploration Program

During the fourth quarter of 2004, the Company is embarking upon an active exploration program in the Gulf of Mexico involving six high-potential, high-risk exploratory wells. Five of these wells will target deeper drilling depths between 14,000 and 21,000 feet subsea. Estimated drilling costs of those wells are expected to range from $8 to $18 million per well. The majority of these wells should be evaluated by the end of 2004.

2004 Production Outlook Update

The Company currently expects that 2004 equivalent hydrocarbon production should reach within 10% of the Company s 2003 production levels, subject to changes in circumstances, acquisitions and many other factors, including changes in timing related to the initiation of production from facilities damaged by Hurricane Ivan.

Results of Operations

Oil and Gas Revenues

The Company s oil and gas revenues for the third quarter of 2004 were $364,024,000, an increase of approximately 31% from oil and gas revenues of $278,484,000 for the third quarter of 2003. The Company s oil and gas revenues for the first nine months of 2004 were $998,010,000, an increase of approximately 12% from oil and gas revenues of $887,347,000 for the first nine months of 2003. The following table reflects an analysis of variances in the Company s oil and gas revenues (expressed in thousands) between 2004 and 2003.

	3rd Qtr 2004 Compared to 3rd Qtr 2003		1st 9 Mos. 2004 Compared to 1st 9 Mos. 2003	
Increase (decrease) in oil and gas revenues resulting in variances in:				
Natural gas -				
Price	$	13,140	$	26,912
Production		23,664		39,218
		36,804		66,130
Crude oil and condensate -				
Price		95,687		160,537
Production		(50,055)		(123,644)
		45,632		36,893
Natural gas liquids		3,104		7,640
Increase in oil and gas revenues	$	85,540	$	110,663

The increase in the Company s oil and gas revenues in the third quarter and first nine months of 2004, compared to the third quarter and first nine months of 2003, is related to increases in the average prices that the Company received for its natural gas, crude oil and condensate and increases in natural gas production volumes, partially offset by a decrease in the Company s crude oil and condensate production volumes. Significant causes for the reduction in hydrocarbon production were the shut-in of several of the Company s offshore fields due to the infrastructure damage caused by Hurricane Ivan in mid-September of 2004 and the first quarter 2004 temporary shutdown of, and subsequent processing issues at, the Benchamas field in the Gulf of Thailand.

	3rd Quarter 2004		3rd Quarter 2003		% Change 2004 to 2003	1st Nine Months 2004		1st Nine Months 2003		% Change 2004 to 2003
Comparison of Increases (Decreases) in:										
Natural Gas										
Average prices										
United States (a)	**$**	**5.52**	$	4.94	**12%**	**$**	**5.60**	$	5.32	**5%**
Kingdom of Thailand (b)	**$**	**2.36**	$	2.56	**(8)%**	**$**	**2.41**	$	2.45	**(2)%**
Company-wide average price	**$**	**4.75**	$	4.25	**12%**	**$**	**4.81**	$	4.48	**7%**
Average daily production volumes (MMcf per day):										
United States (a)		**256.0**		201.3	**27%**		**245.3**		209.6	**17%**
Kingdom of Thailand		**82.7**		83.2	**(1)%**		**80.2**		87.3	**(8)%**

Company-wide average daily production	**338.7**	284.5	**19%**	**325.5**	296.9	**10%**

(a) United States average prices reflect the impact of the Company s price hedging activity for 2003**.** The Company had no price hedging activity during the first nine months of 2004 related to 2004 production. Price hedging activity reduced the average price of the Company s United States natural gas production during the third quarter and first nine months of 2003 by $0.10 and $0.21 per Mcf, respectively. MMcf is an abbreviation for million cubic feet.

(b) The Company is paid for its natural gas production in the Kingdom of Thailand in Thai Baht. The average prices are presented in U.S. dollars based on the revenue recorded in the Company s financial records.

	3rd Quarter 2004	3rd Quarter 2003	% Change 2004 to 2003	1st Nine Months 2004	1st Nine Months 2003	% Change 2004 to 2003
Comparison of Increases (Decreases) in:						
Crude Oil and Condensate						
Average prices (a)						
United States	**$ 44.85**	$ 27.48	**63%**	**$ 37.96**	$ 29.23	**30%**
Kingdom of Thailand	**$ 43.79**	$ 28.35	**54%**	**$ 39.01**	$ 28.67	**36%**
Company-wide average price	**$ 44.40**	$ 27.80	**60%**	**$ 38.34**	$ 29.04	**32%**
Average daily production volumes (Bbls per day):						
United States (a)	**28,951**	39,954	**(28)%**	**32,454**	41,269	**(21)%**
Kingdom of Thailand (b)	**18,277**	21,410	**(15)%**	**17,771**	22,097	**(20)%**
Company-wide average daily production	**47,228**	61,364	**(23)%**	**50,225**	63,366	**(21)%**
Total Liquid Hydrocarbons						
Company-wide average daily production (Bbls per day)(b)	**50,948**	65,288	**(22)%**	**54,526**	67,334	**(19)%**

(a) Average prices are computed on production that is actually sold during the period and include the impact of the Company s price hedging activity. The Company had no price hedging activity during the first nine months of 2004. Price hedging activity reduced the average price of the Company s United States crude oil and condensate production by $0.66 per barrel and $0.61 per barrel during the third quarter and first nine months of 2003, respectively. For United States average prices, sales volumes equate to actual production. However, in the Gulf of Thailand, crude oil and condensate sold may be more or less than actual production. See footnote (b) below. Bbls is an abbreviation for barrels.

(b) Oil and condensate production in the Gulf of Thailand is produced and stored on the FPSO and FSO pending sale and is sold in tanker loads that typically average between 300,000 and 750,000 barrels per sale. Therefore, oil and condensate sales volumes for a given period in the Gulf of Thailand may not equate to actual production. In accordance with generally accepted accounting principles, reported revenues are based on sales volumes. However, the Company believes that actual production volumes also provide a meaningful measure of the Company s operating results. The Company produced 293,000 barrels less than it sold in the third quarter of 2004 and 121,000 barrels less than it sold in the third quarter of 2003. The Company produced 263,000 barrels less than it sold in the first nine months of 2004 and 50,000 barrels more than it sold in the first nine months of 2003.

Natural Gas

Thailand Prices. The price that the Company receives under the gas sales agreement with the Petroleum Authority of Thailand (PTT) is based upon a formula that takes into account a number of factors including, among other items, changes in the Thai/U.S. exchange rate and fuel oil prices in Singapore. The contract price is also subject to adjustments for quality.

Production. The increase in the Company s natural gas production during the third quarter and first nine months of 2004, compared to the comparable 2003 periods, was primarily related to increased natural gas production from the continuing success of the Company s exploration program at the Los Mogotes field in South Texas, increased production from the Madden field in Wyoming and production from fields purchased by the Company subsequent to the third quarter of 2003. These increases for the three-month and nine-month comparative periods were partially offset by decreased production due to the effects of Hurricane Ivan. In addition, for the nine-month comparative periods the increase was partially offset by decreased production resulting from a temporary shutdown of the Benchamas field in the Gulf of Thailand during the first quarter of 2004 to upgrade the Benchamas central processing platform.

Crude Oil and Condensate

Thailand Prices. Since the inception of production from the Tantawan Field, crude oil and condensate have been stored on the FPSO until an economic quantity is accumulated for offloading and sale. The first such sale of crude oil and condensate from the Tantawan Field occurred in July 1997. Commencing in July 1999 when production began from the Benchamas Field, crude oil and condensate from that field has been stored on the FSO and sold as economic quantities are accumulated. A typical sale ranges from 300,000 to 750,000 barrels. Prices that the Company receives for its crude oil and condensate production from Thailand are based on world benchmark prices, typically as a differential to either Malaysian TAPIS or Brent crude, and are denominated in U.S. dollars.

Production. The decrease in the Company s crude oil and condensate production during the third quarter and first nine months of 2004, compared to the third quarter and first nine months of 2003, resulted primarily from the shut-in of Gulf of Mexico platforms due to the effects of Hurricane Ivan, the temporary shutdown of, and subsequent processing issues at, the Benchamas field in the Gulf of Thailand, natural production decline at the Company s Main Pass Block 61/62 field and, to a lesser extent, natural production declines at other properties.

In accordance with generally accepted accounting principles, the Company records its oil production in the Kingdom of Thailand at the time of sale, rather than when produced. At the end of each quarter, the crude oil and condensate stored on board the FSO and FPSO pending sale is accounted for as inventory at cost. Reported revenues are based on sales volumes. When a tanker load of oil is sold in Thailand, the entire amount will be accounted for as production sold, regardless of when it was produced. As of September 30, 2004, the Company had approximately 233,000 net barrels stored on board the FPSO and FSO.

NGL. The Company s oil and gas revenues, and its total liquid hydrocarbon production, also reflect the production and sale by the Company of NGL, which are liquid products that are extracted from natural gas production. The increase in NGL revenues for the third quarter and first nine months of 2004, compared with the third quarter and first nine months of 2003, was primarily related to an increase in NGL prices received from $19.57 and $21.56 per barrel in the third quarter and first nine months of 2003, respectively, to $29.71 and $26.30 per barrel in the third quarter and first nine months of 2004, respectively.

Costs and Expenses

	3rd Quarter 2004	3rd Quarter 2003	% Change 2004 to 2003	1st Nine Months 2004	1st Nine Months 2003	% Change 2004 to 2003
Comparison of Increases (Decreases) in:						
Lease Operating Expenses						
United States	**$ 24,535,000**	$ 19,993,000	**23%**	**$ 70,871,000**	$ 59,416,000	**19%**
Kingdom of Thailand	**$ 11,799,000**	$ 11,275,000	**5%**	**$ 32,688,000**	$ 32,395,000	**1%**
Total Lease Operating Expenses	**$ 36,334,000**	$ 31,268,000	**16%**	**$ 103,559,000**	$ 91,811,000	**13%**
General and Administrative Expenses	**$ 18,747,000**	$ 16,936,000	**11%**	**$ 52,753,000**	$ 45,362,000	**16%**
Exploration Expenses	**$ 5,186,000**	$ 1,432,000	**262%**	**$ 18,573,000**	$ 5,091,000	**265%**
Dry Hole and Impairment Expenses	**$ 18,085,000**	$ 4,568,000	**296%**	**$ 54,550,000**	$ 10,666,000	**411%**
Depreciation, Depletion and Amortization (DD&A) Expenses	**$ 96,759,000**	$ 79,688,000	**21%**	**$ 277,212,000**	$ 244,454,000	**13%**
DD&A rate	**$ 1.58**	$ 1.27	**24%**	**$ 1.54**	$ 1.28	**20%**
Mcfe sold (a)	**61,046,693**	62,936,645	**(3)%**	**180,414,157**	191,052,649	**(6)%**
Production and Other Taxes	**$ 28,606,000**	$ 8,084,000	**254%**	**$ 52,380,000**	$ 27,269,000	**92%**
Transportation and Other	**$ 5,452,000**	$ 5,610,000	**(3)%**	**$ 15,609,000**	$ 21,002,000	**(26)%**
Interest						
Charges	**$ (6,044,000)**	$ (10,255,000)	**(41)%**	**$ (22,115,000)**	$ (36,934,000)	**(40)%**
Capitalized Interest Expense	**$ 3,441,000**	$ 4,246,000	**(19)%**	**$ 11,457,000**	$ 12,377,000	**(7)%**
Loss on Debt Extinguishment	**$**	$ (5,893,000)	**(100)%**	**$ (10,893,000)**	$ (5,893,000)	**85%**
Income Tax Expense	**$ (66,687,000)**	$ (53,217,000)	**25%**	**$ (182,265,000)**	$ (175,553,000)	**4%**

(a) Mcfe stands for thousands of cubic feet equivalent

Lease Operating Expenses

The increase in United States lease operating expenses for the third quarter and first nine months of 2004, compared to the respective 2003 periods, is related primarily to increased expenses incurred on the properties acquired by the Company during the latter part of 2003, increased maintenance expenses on several of the Company s significant offshore properties and also to increased expenses incurred as the Company continues to expand production in the Los Mogotes field in South Texas.

The increase in lease operating expenses in the Kingdom of Thailand for the third quarter of 2004, compared to the third quarter of 2003, primarily related to the addition of five production platforms during the past twelve months. A substantial portion of the Company s lease operating expenses in the Kingdom of Thailand are fixed costs related to the lease payments made in connection with the bareboat charters of the FPSO for the Tantawan field and the FSO for the Benchamas field. Collectively, these lease payments accounted for approximately $3.6 million and $10.9 million (net to the Company s interest) of the Company s Thailand lease operating expenses for the third quarter and first nine months, respectively, of 2004 and 2003. The Company currently expects these lease payments to remain relatively constant at approximately $14.5 million per year (net to the Company s interest) for the next several years.

On a per unit of production basis, the Company s total lease operating expenses have increased from an average of $0.50 and $0.48 per Mcfe for the third quarter and first nine months of 2003 to $0.61 and $0.58 per Mcfe for the third quarter and first nine months of 2004. The per unit of production increase for the first nine months of 2004 is primarily related to the shut-in of domestic production due to Hurricane Ivan during the third quarter of 2004 and to the Benchamas production shutdown during the first quarter 2004. The Benchamas shutdown significantly reduced crude oil and condensate production while the fixed operating expenses on the Benchamas field did not decrease proportionately due to the factors discussed above.

General and Administrative Expenses

The increase in general and administrative expenses for the third quarter and first nine months of 2004 compared with the respective 2003 periods, is primarily related to increases in compensation and related benefit expense and to increased professional fees (due in part to compliance with Sarbanes-Oxley legislation). On a per unit of production basis, the Company s general and administrative expenses increased to $0.32 per Mcfe in the third quarter of 2004 from $0.27 per Mcfe in the third quarter of 2003. The Company s general and administrative expenses increased to $0.29 per Mcfe in the first nine months of 2004 from $0.24 per Mcfe in the first nine months of 2003.

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. The increase in exploration expenses for the third quarter of 2004, compared to the third quarter of 2003, resulted primarily from the acquisition of approximately $3.8 million of 3-D seismic data in the Company s Gulf Coast division. The increase in exploration expenses for the first nine months of 2004, compared to the first nine months of 2003, resulted primarily from the acquisition of approximately $8.1 million of 3-D seismic data covering approximately 1.4 million acres of the Gulf of Mexico during the first quarter of 2004 and the acquisition of approximately $7.1 million of seismic data in the Gulf Coast division during the second and third quarters of 2004. There were no expenditures of comparable size to those discussed above incurred during the third quarter or first nine months of 2003.

Dry Hole and Impairment Expenses

Dry hole and impairment expenses relate to costs of unsuccessful exploratory wells drilled and impairment of oil and gas properties. The increase in dry hole and impairment expense for the third quarter of 2004, compared to the third quarter of 2003, was primarily the result of three unsuccessful domestic exploratory wells totaling approximately $8.0 million, and the impairment of costs related to both a domestic property and the Company s foreign operations, totaling approximately $8.6 million in the aggregate. In the third quarter of 2003, the Company drilled two unsuccessful exploratory wells, totaling approximately $4.3 million. The increase in dry hole and impairment expense for the first nine months of 2004, compared to the respective 2003 period, was primarily the result of unsuccessful exploratory wells in the Company s Hungary acreage, which were evaluated during the first half of 2004, totaling approximately $26.5 million, in addition to the third quarter items mentioned above. During the second quarter and third quarter of 2004, the Company also recognized dry hole and impairment expense of approximately $5.0 million related to an unsuccessful exploratory well drilled in the Danish North Sea.

Generally accepted accounting principles also require that if the expected future cash flow of the Company s reserves on a property fall below the cost that is recorded on the Company s books, these properties must be impaired and written down to the property s fair value. Depending on market conditions, including the prices for oil and natural gas, and the Company s results of operations, a similar test may be conducted at any time to determine whether impairments are appropriate. Depending on the results of this test, impairment could be required on some of the Company s properties and this impairment could have a material negative non-cash impact on the Company s earnings and balance sheet. During the third quarter and first nine months of both 2004 and 2003, the Company recognized miscellaneous impairments on various non-producing prospects and leases.

Depreciation, Depletion and Amortization Expenses

The Company s provision for DD&A expense is based on its capitalized costs and is determined on a cost center by cost center basis using the units of production method. The Company generally creates cost centers on a field-by-field basis for oil and gas activities in the Gulf of Mexico and Gulf of Thailand. 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 increase in the Company s DD&A expenses for the third quarter and first nine months of 2004 compared to the respective 2003 periods resulted primarily from an increase in the Company s composite DD&A rate, partially offset by a decrease in the Company s equivalent hydrocarbon sales.

The increase in the composite DD&A rate for all of the Company s producing fields for the third quarter and first nine months of 2004, compared to the respective 2003 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 properties in the Gulf of Mexico which were shut-in due to hurricane downtime, and the Benchamas field in the Gulf of Thailand) and a corresponding increase in the percentage of the Company s production coming from fields that have DD&A rates that are higher than the Company s recent historical composite rate (principally increased production from domestic onshore properties acquired by acquisition).

Production and Other Taxes

The increase in production and other taxes during the third quarter and first nine months of 2004, compared to the respective 2003 periods, relates primarily to Special Remuneration Benefit (SRB) taxes in the Kingdom of Thailand and to increased severance, property and franchise taxes in the United States resulting from the higher product prices received by the Company. The SRB is a payment to the Thai government required by the Company s concession agreement after certain specified revenue, expenditure and drilling criteria have been achieved. The Company recognized $14,759,000 and $4,593,000 during the third quarters of 2004 and 2003, respectively, of the SRB obligation. The Company recognized $20,774,000 and $8,819,000 during the first nine months of 2004 and 2003, respectively, related to the SRB obligation. It is currently anticipated that the Company will continue to pay SRB for the foreseeable future.

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, valuation allowances placed on accounts receivable, a royalty settlement reserve on one of the Company s offshore blocks, tubular inventory valuation write-offs and allowances, ineffectiveness on hedge transactions and various other operating expenses, none of which represents more than 5% of this expense category. The decrease in transportation and other expense for the first nine months of 2004, compared to the first nine months of 2003, relates primarily to a reduction in the Company s transportation expenses, and the inclusion in 2003 of $3.4 million of valuation allowances and reserves on items discussed above, for which no comparable expenses were incurred in 2004. The Company incurred transportation expense of $3,402,000 and $9,515,000 in the third quarter and first nine months of 2004, respectively. The Company incurred transportation expense of $3,035,000 and $10,531,000 in the third quarter and first nine months of 2003, respectively.

Interest

Interest Charges. The decrease in the Company s interest charges for the third quarter and first nine months of 2004, compared to the third quarter and first nine months of 2003, resulted primarily from a decrease in the average amount of the Company s outstanding debt.

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 decrease in capitalized interest for the third quarter and first nine months of 2004, compared to the respective 2003 periods, resulted primarily from a decrease in the weighted average interest rate on the Company s outstanding borrowings. The interest rates on borrowings repaid during the prior year were above the rates of the borrowings currently remaining, resulting in a lower weighted average rate to be applied to the cost of oil and gas projects in progress. The decreased weighted average interest rate was partially offset by an increase in the amount of oil and gas projects in progress subject to interest capitalization during the third quarter and first nine months of 2004 (approximately $219,000,000 and $216,000,000, respectively), compared to the third quarter and first nine months of 2003 (approximately $185,000,000 and $192,000,000, respectively).

Loss on Debt Extinguishment

The Company gave notice in the first quarter of 2004 of its intent to redeem all $150,000,000 of its 2009 Notes at 105.188% of their face amount. On April 19, 2004, the Company paid $157,782,000 (excluding accrued interest) in cash to holders of the 2009 Notes. The cash redemption payment was funded through borrowings under the Company s existing bank credit facility. The Company recorded a pre-tax loss on debt extinguishment related to the redemption of the 2009 Notes of $10,893,000 in the second quarter of 2004. During the third quarter of 2003, the Company recorded pre-tax losses of $5,893,000 on debt extinguishment related to the redemption of its 2006 and 2007 Notes.

Income Tax Expense

Changes in the Company s income tax expense are a function of the Company s consolidated effective tax rate and its pre-tax income. The increase in the Company s tax expense for the third quarter of 2004, compared to the third quarter of 2003, resulted primarily from increased pre-tax income during the 2004 period. The Company s consolidated effective tax rate for the third quarters of both 2004 and 2003 was 44%.

The increase in the Company s tax expense for the first nine months of 2004, compared to the first nine months of 2003, resulted primarily from an increase in the Company s effective tax rate, partially offset by decreased pre-tax income during the 2004 period. The Company s consolidated effective tax rate for the first nine months of 2004 was 45%, compared to an effective tax rate for the first nine months of 2003 of 42%. The higher effective tax rate was the result of a higher percentage of the Company s pre-tax income being derived from its Thailand operations during the 2004 period as compared to the 2003 period. The Thailand income is taxed at a rate higher than the U.S. statutory rate.

Cumulative Effect of Change in Accounting Principle

The Company adopted SFAS No. 143, Accounting for Asset Retirement Obligations, (SFAS 143) as of January 1, 2003, which required the Company to record the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred. Upon adoption of SFAS 143, the Company was required to recognize a liability for the present value of all legal obligations associated with the retirement of tangible long-lived assets and an asset retirement cost was capitalized as part of the carrying value of the associated asset. Upon initial application of SFAS 143, the Company recorded an after-tax charge to recognize the cumulative effect of a change in accounting principle of $4,166,000. This charge was required in order to recognize a liability for any existing AROs adjusted for cumulative accretion, and also to increase the carrying amount of the associated long-lived asset and its accumulated depreciation.

Liquidity and Capital Resources

The Company s primary needs for cash are for exploration, development, acquisition and production of oil and gas properties, repayment of principal and interest on outstanding debt and payment of income taxes. The Company funds its exploration and development activities primarily through internally generated cash flows and budgets capital expenditures based on projected cash flows. The Company adjusts capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition results, and cash flow. The Company has historically utilized net cash provided by operating activities, available cash, debt, and equity as capital resources to obtain necessary funding for all other cash needs.

The Company s cash flow provided by operating activities for the first nine months of 2004 was $572,849,000 compared to cash flow from operating activities of $579,462,000 in the first nine months of 2003. The decrease is attributable primarily to higher expenses (principally income taxes and lease operating expenses), partially offset by the higher oil and gas prices discussed under Results of Operations above. Cash flow from operating activities during the first nine months of 2004 was more than adequate to fund $486,338,000 in cash expenditures for capital and exploration projects for the year. The Company also repaid approximately $95,782,000 of cash (net of borrowings) to settle debt obligations (including the repayment of the 2009 Notes mentioned below) and paid $9,581,000 of dividends on the Company s common stock during the first nine months of 2004. As of September 30, 2004, the Company had cash and cash equivalents of $170,807,000 (including $160,832,000 in international subsidiaries which the Company intends to reinvest in its foreign operations) and long-term debt obligations of $401,000,000 with no repayment obligations until 2006. On April 19, 2004, the Company redeemed all $150,000,000 of its 2009 Notes for $157,782,000 in cash. The Company may determine to repurchase additional debt in the future, including in market transactions, privately negotiated transactions or otherwise, depending on market conditions, liquidity requirements, contractual restrictions and other factors.

Effective October 25, 2004, the Company s lenders redetermined the borrowing base under its Credit Agreement at $900,000,000. The available borrowing capacity under the Credit Agreement is currently $515,000,000. As of October 20, 2004, the Company had an outstanding balance of $163,000,000 under its Credit Agreement.

LIBOR Rate Advances

Under separate Promissory Note Agreements dated May 8, 2004 and September 13, 2004, two of the Company s lenders make available to the Company LIBOR rate advances on an uncommitted basis up to $50,000,000. Advances drawn under these agreements are reflected as long-term debt on the Company s balance sheet because the Company currently has the ability and intent to reborrow such amounts under its Credit Agreement. The Company s 2011 Notes may restrict all or a portion of the amounts that may be borrowed under the Promissory Note Agreements as senior debt. The Promissory Note Agreements permit either party to terminate the letter agreements at any time upon three-business days notice. As of October 20, 2004, there was $40,000,000 outstanding under this agreement.

Future Capital and Other Expenditure Requirements

The Company s capital and exploration budget for 2004, which does not include any interest which may be capitalized resulting from projects in progress, has been established by the Company s Board of Directors at $820,000,000, of which approximately $492,000,000 was incurred in the nine-month period ended September 30, 2004. The Company has included 390 gross wells in its 2004 capital and exploration budget (248 of which were drilled in the first nine months of 2004), including wells in the United States, the Kingdom of Thailand, Hungary and Denmark. The Company currently anticipates that its available cash and cash investments, cash provided by operating activities and funds available under its Credit Agreement 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 remaining debt instruments, the general economic and regulatory climate and other factors deemed relevant by the Company s Board of Directors.

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 limited use of a variety of derivative financial instruments only for non-trading purposes as a hedging strategy to manage commodity prices associated with oil and gas sales and to reduce the impact of commodity price fluctuations.

Current Hedging Activity

Commodity Price Risk

As of September 30, 2004, 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 these contracts as cash flow hedges designed to achieve a more predictable cash flow, as well as to reduce its exposure to price volatility. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The use of derivatives also involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. Currently, the Company does not expect losses due to creditworthiness of its counterparties.

The gas hedging transactions are generally settled based upon the average of the reporting settlement prices on the NYMEX for the last three trading days of a particular contract month. The oil hedging transactions are generally settled based on the average of the reporting settlement prices for West Texas Intermediate on the NYMEX for each trading day of a particular calendar month. For any particular collar transaction, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price for such transaction, and the Company is required to make a 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 September 30, 2004, are as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price Floor		NYMEX Contract Price Ceiling		Fair Value of Asset/(Liability)
Natural Gas Contracts (MMBtu) (a)						
Collar Contracts:						
January 2005 - December 2005	5,475	$	5.50	$	8.00	$ (1,648,000)
January 2006 - December 2006	5,475	$	5.00	$	7.50	$ (2,002,000)

(a) MMBtu means million British Thermal Units.

In October 2004, the Company entered into additional natural gas and crude oil collars 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. Further details related to these hedging activities are as follows:

Contract Period and	NYMEX Contract Price

Type of Contract	Volume		Floor		Ceiling
Natural Gas Contracts (MMBtu)					
Collar Contracts:					
January 2005 - December 2005	1,825	$	6.00	$	9.30
January 2005 - December 2005	1,825	$	6.00	$	9.25
January 2006 - December 2006	3,650	$	5.50	$	8.25
Crude Oil Contracts (Barrels)					
Collar Contracts:					
January 2005 - December 2005	1,825,000	$	40.00	$	62.50

Interest Rate Risk

From time to time, the Company has entered into various financial instruments, such as interest rate swaps, to manage the impact of changes in interest rates. As of October 20, 2004, the Company has no open interest rate swap or interest rate lock agreements. Therefore, the Company s exposure to changes in interest rates primarily results from its short-term and long-term debt with both fixed and floating interest rates. The following table presents principal or notional amounts (stated in thousands) and related average interest rates by year of maturity for the Company s debt obligations and their indicated fair market value at September 30, 2004:

	2004	2005	2006	2007	2008	Thereafter	Total	Fair Value
Long-Term Debt:								
Variable Rate	$ 0	$ 0	$ 201,000	$ 0	$ 0	$ 0	$ 201,000	$ 201,000
Average Interest Rate			2.89%				2.89%	
Fixed Rate	$ 0	$ 0	$ 0	$ 0	$ 0	$ 200,000	$ 200,000	$ 221,500
Average Interest Rate						8.25%	8.25%	

Foreign Currency Exchange Rate Risk

In addition to the U.S. dollar, the Company and certain of its subsidiaries conduct their business in Thai Baht and Hungarian Forint and are therefore subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing and investing transactions. The Company conducts a substantial portion of its oil and gas production and sales in Southeast Asia. Southeast Asia in general, and the Kingdom of Thailand in particular, have experienced severe economic difficulties in the recent past, including sharply reduced economic activity, illiquidity, highly volatile foreign currency exchange rates and unstable stock markets. The economic situation in Thailand and the volatility of the Thai Baht against the dollar could have a material impact on the Company s Thailand operations and prices that the Company receives for its oil and gas production there. Although the Company s sales to PTT under the Gas Sales Agreement are denominated in Baht, because predominantly all of the Company s crude oil sales and its capital and most other expenditures in the Kingdom of Thailand are denominated in U.S. dollars, the dollar is the functional currency for the Company s operations in the Kingdom of Thailand. As of October 20, 2004, the Company is not a party to any foreign currency exchange agreement.

Exposure from market rate fluctuations related to activities in Hungary, where the Company s functional currency is the U.S. dollar, is not material at this time.

ITEM 4. Controls and Procedures.

The Company carried out an evaluation, under the supervision and with the participation of the Company s management, including the Company s Chairman, President and Chief Executive Officer and its Senior Vice President and Chief Financial Officer, of the effectiveness of the Company s disclosure controls and procedures pursuant to Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended, as of the end of the period covered by this quarterly report. Based upon that evaluation, the Company s Chairman, President and Chief Executive Officer and its Senior Vice President and Chief Financial Officer concluded that the Company s disclosure controls and procedures are effective in timely alerting them to material information required to be included in our periodic Securities and Exchange Commission filings.

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 6. **Exhibits**

Exhibits

*3.1	Restated Certificate of Incorporation of Pogo Producing Company, as filed on April 28, 2004 (Exhibit 3.1, Quarterly Report on Form 10-Q for the quarter ended March 31, 2004, File No. 1-7796).
*3.2	Bylaws of Pogo Producing Company, as amended and restated through July 16, 2002 (Exhibit 4.1, Quarterly Report on Form 10-Q for the quarter ended June 30, 2002, File No. 1-7792).
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: October 26, 2004