POGO PRODUCING CO
Form 10-Q
October 15, 2003

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 September 30, 2003

OR

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

For the transition period from __________ to __________

Commission file number 1-7792

POGO PRODUCING COMPANY

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**74-1659398**
(State or Other Jurisdiction of	**(I.R.S. Employee**

Incorporation or Organization)	**Identification No.)**
5 Greenway Plaza, Suite 2700	
Houston, Texas	**77046-0504**
(Address of principal executive offices)	**(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 x No ¨

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

Registrant s number of common shares outstanding as of October 13, 2003: 63,745,605

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Statements of Income (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	(Expressed in thousands, except per share amounts)			
Revenues:				
Oil and gas	$ 277,067	$ 203,919	$ 882,464	$ 531,457
Other	848	3,889	1,804	3,646
Total	277,915	207,808	884,268	535,103
Operating Costs and Expenses:				
Lease operating	32,886	29,734	97,459	87,862
General and administrative	16,936	14,445	45,362	36,815
Exploration	1,432	2,508	5,091	3,684
Dry hole and impairment	4,568	8,179	10,666	16,674
Depreciation, depletion and amortization	79,688	73,960	244,454	213,708
Production and other taxes	8,084	5,254	27,269	12,994
Accretion and other	8,468	2,133	16,364	2,314
Total	152,062	136,213	446,665	374,051
Operating Income	125,853	71,595	437,603	161,052
Interest:				
Charges	(10,255)	(14,364)	(36,934)	(43,452)
Income	446	404	1,380	1,316
Capitalized	4,246	5,933	12,377	19,445
Minority Interest - Dividends and costs associated with preferred securities of a subsidiary trust				(4,140)
Foreign Currency Transaction Gain (Loss)	587	(458)	1,149	873
Income Before Taxes and Cumulative Effect of Change in Accounting Principle	120,877	63,110	415,575	135,094
Income Tax Expense	(53,217)	(31,473)	(175,553)	(65,814)
Income Before Cumulative Effect of Change in Accounting Principle	67,660	31,637	240,022	69,280

Cumulative Effect of Change in Accounting Principle			(4,166)	
Net Income	$ 67,660	$ 31,637	$ 235,856	$ 69,280
Earnings Per Common Share				
Basic:				
Income before cumulative effect of change in accounting principle	$ 1.07	$ 0.52	$ 3.86	$ 1.22
Cumulative effect of change in accounting principle			(0.07)	
Net income	$ 1.07	$ 0.52	$ 3.79	$ 1.22
Diluted:				
Income before cumulative effect of change in accounting principle	$ 1.06	$ 0.51	$ 3.74	$ 1.17
Cumulative effect of change in accounting principle			(0.07)	
Net income	$ 1.06	$ 0.51	$ 3.67	$ 1.17
Dividends Per Common Share	$ 0.05	$ 0.03	$ 0.15	$ 0.09
Weighted Average Number of Common Shares and Potential Common Shares Outstanding:				
Basic	63,379	60,779	62,170	56,953
Diluted	63,963	64,454	64,826	64,111

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Balance Sheets (Unaudited)

	September 30, 2003	December 31, 2002
	(Expressed in thousands, except share amounts)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 161,601	$ 134,449
Accounts receivable	108,622	101,807
Other receivables	43,886	14,634
Deferred income tax		20,041
Inventories - Product	2,717	2,501
Inventories - Tubulars	8,450	9,406
Other	8,983	4,818
Total current assets	334,259	287,656
Property and Equipment:		
Oil and gas, on the basis of successful efforts accounting		
Proved properties	3,649,627	3,396,669
Unevaluated properties	141,380	141,094
Other, at cost	28,650	26,626
	3,819,657	3,564,389
Accumulated depreciation, depletion and amortization		
Oil and gas	(1,606,541)	(1,389,976)
Other	(18,494)	(15,364)
	(1,625,035)	(1,405,340)
Property and equipment, net	2,194,622	2,159,049
Other Assets:		
Deferred income tax	2,416	2,416
Debt issue costs	8,000	11,368
Foreign value added taxes receivable	3,736	13,908
Other	18,408	17,196
	32,560	44,888
	$ 2,561,441	$ 2,491,593

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Balance Sheets (Unaudited)

	September 30, 2003	December 31, 2002
	(Expressed in thousands, except share amounts)	
Liabilities and Shareholders Equity		
Current Liabilities:		
Accounts payable - operating activities	$ 59,873	$ 41,102
Accounts payable - investing activities	57,830	68,963
Accrued interest payable	10,053	11,096
Income taxes payable	28,510	15,527
Accrued payroll and related benefits	2,988	3,011
Deferred income tax	5,324	5,324
Price hedge contracts	1,079	2,433
Other	12,969	2,229
Total current liabilities	178,626	149,685
Long-Term Debt	369,174	722,903
Deferred Income Tax	526,929	526,897
Asset Retirement Obligation	69,125	
Other Liabilities and Deferred Credits	19,831	14,324
Total liabilities	1,163,685	1,413,809
Commitments and Contingencies		
Shareholders Equity:		
Preferred stock, $1 par; 4,000,000 shares authorized		
Common stock, $1 par; 200,000,000 shares authorized, 63,797,764 and 61,061,888 shares issued, respectively	63,798	61,062
Additional capital	913,273	822,526
Retained earnings	428,671	202,155
Accumulated other comprehensive loss	(2,510)	(6,249)
Deferred compensation	(3,766)	
Treasury stock (55,359 shares), at cost	(1,710)	(1,710)
Total shareholders equity	1,397,756	1,077,784
	$ 2,561,441	$ 2,491,593

See accompanying notes to consolidated financial statements.

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POGO PRODUCING COMPANY AND SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows (Unaudited)

	Nine Months Ended September 30,	
	2003	2002
	(Expressed in thousands)	
Cash Flows from Operating Activities:		
Cash received from customers	$ 911,304	$ 506,759
Operating, exploration, and general and administrative expenses paid	(167,812)	(154,713)
Interest paid	(36,373)	(38,122)
Income taxes paid	(129,612)	(9,288)
Income taxes received		25,884
Value added taxes paid	(4,287)	(6,523)
Value added taxes received	14,459	1,763
Price hedge contracts	(14,612)	20,449
Other	6,395	2,090
Net cash provided by operating activities	579,462	348,299
Cash Flows from Investing Activities:		
Capital expenditures	(241,687)	(276,392)
Purchase of proved reserves	(18,968)	
Proceeds from the sale of properties	47	4,255
Net cash used in investing activities	(260,608)	(272,137)
Cash Flows from Financing Activities:		
Borrowings under senior debt agreements	417,012	529,995
Payments under senior debt agreements	(556,000)	(585,000)
Redemption of debt	(176,578)	
Payments of cash dividends on common stock	(9,340)	(5,064)
Payments of preferred dividends of a subsidiary trust		(4,850)
Payment of debt issue costs	(100)	(182)
Proceeds from exercise of stock options and other	32,677	17,252
Net cash used in financing activities	(292,329)	(47,849)
Effect of exchange rate changes on cash	627	62
Net increase in cash and cash equivalents	27,152	28,375
Cash and cash equivalents at the beginning of the year	134,449	94,294
Cash and cash equivalents at the end of the period	$ 161,601	$ 122,669
Reconciliation of net income to net cash provided by operating activities:		
Net income	$ 235,856	$ 69,280
Adjustments to reconcile net income to net cash provided by operating activities -		
Cumulative effect of change in accounting principle	4,166	

Minority interest		4,140
Accretion and other	21,054	(873)
(Gains) Losses from the sales of properties	87	(3,100)
Depreciation, depletion and amortization	244,454	213,708
Dry hole and impairment	10,666	16,674
Interest capitalized	(12,377)	(19,445)
Price hedge contracts	4,899	13,016
Deferred income taxes	32,961	60,017
Change in operating assets and liabilities	37,696	(5,118)
Net cash provided by operating activities	$ 579,462	$ 348,299

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,					
	2003			2002		
	Shareholders Equity			Shareholders Equity		
	Shares	Amount	Compre-hensive Income	Shares	Amount	Compre-hensive Income
	(Expressed in thousands, except share amounts)					
Common Stock:						
$1.00 par-200,000,000 shares authorized						
Balance at beginning of year	61,061,888	$ 61,062		53,690,827	$ 53,691	
Shares issued for stock options exercised and other	1,557,369	1,558		845,437	845	
Shares issued for 2006 Notes conversion	1,008,299	1,008				
Shares issued as compensation	170,208	170		39,055	39	
Shares issued for Trust Preferred Securities conversion				6,309,972	6,310	
Issued at end of period	63,797,764	63,798		60,885,291	60,885	
Additional Capital:						
Balance at beginning of year		822,526			659,227	
Shares issued for stock options exercised and other		42,526			18,845	
Shares issued for 2006 Notes conversion		41,186				
Shares issued as compensation		6,816			1,124	
Stock options granted		219				
Shares issued for Trust Preferred Securities conversion					138,715	
Balance at end of period		913,273			817,911	
Retained Earnings:						
Balance at beginning of year		202,155			102,019	
Net income		235,856	$ 235,856		69,280	$ 69,280
Dividends ($0.15 and $0.09 per common share in 2003 and 2002, respectively)		(9,340)			(5,064)	
Balance at end of period		428,671			166,235	
Deferred Compensation - Restricted Stock		(3,766)	(3,766)			
Accumulated Other Comprehensive Income (Loss):						
Balance at beginning of year		(6,249)			10,272	
Change in fair value of price hedge contracts		(8,619)	(8,619)		(7,936)	(7,936)
Reclassification adjustment for losses (gains) included in net income		12,358	12,358		(4,831)	(4,831)

Balance at end of period		(2,510)			(2,495)	
Comprehensive Income			$ 235,829			$ 56,513
Treasury Stock:						
Balance at beginning of year	(55,359)	(1,710)		(15,575)	(324)	
Activity during the period						
Balance at end of period	(55,359)	(1,710)		(15,575)	(324)	
Common Stock Outstanding, at the End of the Period	63,742,405			60,869,716		
Total Shareholders Equity		$ 1,397,756			$ 1,042,212	

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, 2002.

(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 share (diluted earnings per share) consider the effect of dilutive securities as set out below. Also presented below are securities that have not been included in the computation of earnings per share in one or more periods because their effect would have been antidilutive. Amounts are expressed in thousands, except per share amounts.

	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

	Three Months Ended September 30, 2002			Nine Months Ended September 30, 2002		
	Income	Shares	Per Share	Income	Shares	Per Share
Basic earnings per share -	$ 31,637	60,779	$ 0.52	$ 69,280	56,953	$ 1.22

Effect of dilutive securities:						
Options to purchase common shares		949			897	
2006 Notes	1,028	2,726		3,083	2,726	
Trust Preferred Securities [c]				2,660	3,535	
Diluted earnings per share	$ 32,665	64,454	$ 0.51	$ 75,023	64,111	$ 1.17
Antidilutive securities -						
Options to purchase common shares		143	$ 38.00		178	$ 36.65

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

(b) The 2006 Notes were redeemed on July 7, 2003. Prior to redemption a portion of the 2006 Notes were converted to 1,008,299 shares of common stock.

(c) The Trust Preferred securities were converted to common stock on June 3, 2002.

(3) HEDGING ACTIVITIES -

As of September 30, 2003, the Company held various derivative instruments. During 2002 and 2003, 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, 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. During the three-month and nine-month periods ended September 30, 2002, the Company recognized a pre-tax loss of $565,000 ($367,000 after taxes) and a pre-tax gain of $7,433,000 ($4,831,000 after taxes), respectively, from its price hedge contracts which

POGO PRODUCING COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Unaudited)

are included in oil and gas revenues. No ineffectiveness on these hedge contracts was recognized in income during the first nine months of 2002. Net unrealized gains on derivative instruments of $3,739,000, net of deferred taxes of $2,013,000, have been reflected as a component of other comprehensive income for the nine months ended September 30, 2003. Based on the fair market value of the hedge contracts as of September 30, 2003, the Company would reclassify additional pre-tax losses of approximately $3,862,000 (approximately $2,510,000 after taxes) from accumulated other comprehensive loss (shareholders equity) to net income during the next three 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 contract 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, 2003 are as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price		Fair Value of Asset/(Liability)
		Floor	Ceiling	
Natural Gas Contracts (MMBtu) [a]				
Collar Contracts:				
October 2003 - December 2003	3,680	$ 3.85	$ 5.00	$ (822,000)
October 2003 - December 2003	1,840	$ 4.25	$ 7.00	$ 56,000
Crude Oil Contracts (Barrels)				
Collar Contracts:				
October 2003 - December 2003	920,000	$ 25.00	$ 30.00	$ (313,000)

[a] MMBtu means million British Thermal Units.

(4) CHANGE IN ACCOUNTING PRINCIPLE

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. Upon settlement of the liability, the Company will settle the obligation against its recorded amount and will record any resulting gain or loss.

Activity related to the Company s ARO during the nine months ended September 30, 2003 is as follows (in thousands):

	Nine Months Ended September 30, 2003
Initial ARO as of January 1, 2003	$ 63,643
Liabilities incurred during period	1,908
Liabilities settled during period	(28)
Accretion expense	3,602
Balance of ARO as of September 30, 2003	$ 69,125

POGO PRODUCING COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Unaudited)

For the three and nine months ended September 30, 2003, the Company recognized depreciation expense related to its ARC of $918,000 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 (net of related income tax benefit of $2,707,000).

Had the Company adopted SFAS 143 on January 1, 2002, the pro forma ARO would have been $58,187,000. Had SFAS 143 been applied retroactively during the three months and nine months ended September 30, 2002, the Company s net income and earnings per share would have been as follows (expressed in thousands, except per share amounts):

	Three Months Ended September 30, 2002		Nine Months Ended September 30, 2002	
	As Reported	Pro forma	As Reported	Pro forma
Net Income	$ 31,637	$ 31,433	$ 69,280	$ 68,682
Earnings per share:				
Basic	$ 0.52	$ 0.52	$ 1.22	$ 1.21
Diluted	$ 0.51	$ 0.50	$ 1.17	$ 1.16

(5) GEOGRAPHIC INFORMATION -

Financial information by geographic segment is presented below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	**2002**	**2003**	**2002**
	(Expressed in thousands)			
Revenues:				
North America	$ 199,041	$ 146,215	$ 654,216	$ 382,099
Kingdom of Thailand	78,874	61,535	230,029	152,946
Other		58	23	58
Total	$ 277,915	$ 207,808	$ 884,268	$ 535,103
Operating Income (Loss):				
North America	$ 88,042	$ 42,341	$ 324,238	$ 97,519

Kingdom of Thailand	38,635	29,572	115,839	64,806
Other	(824)	(318)	(2,474)	(1,273)
Total	$ 125,853	$ 71,595	$ 437,603	$ 161,052

(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). Prior to January 1, 2003, the Company accounted for Stock Awards using the intrinsic value recognition provisions of APB Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations. Under this method, the Company recognized no compensation expense for stock options granted when the exercise price of the options was equal to or greater than the quoted market price of the Company s common stock on the grant date. Effective January 1, 2003, the Company adopted the fair value recognition provisions of SFAS No. 123, Accounting for Stock Based Compensation (SFAS 123), and the prospective method transition provisions of SFAS 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 537,000 shares with a fair market value of $9,790,000 during the three-month period ended September 30, 2003, and 547,000 shares of common stock with a fair market value of $9,920,000 during the nine-month period ended September 30, 2003.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Unaudited)

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 ended September 30, 2003 and 2002 (in thousands of dollars, except per share amounts):

		Three Months Ended September 30,		Nine Months Ended September 30,	
		2003	**2002**	**2003**	**2002**
Net income, as reported		$ 67,660	$ 31,637	$ 235,856	$ 69,280
Add:	Employee stock-based compensation expense, net of related tax effects, included in net income, as reported	1,409	1,163	1,412	1,163
Deduct:	Total employee stock-based compensation expense, determined under fair value method for all awards, net of related tax effects	(2,249)	(2,193)	(5,312)	(4,909)
Net income, pro forma		$ 66,820	$ 30,607	$ 231,956	$ 65,534
Earnings per share:					
	Basic - as reported	$ 1.07	$ 0.52	$ 3.79	$ 1.22
	Basic - pro forma	$ 1.05	$ 0.50	$ 3.73	$ 1.15
	Diluted - as reported	$ 1.06	$ 0.51	$ 3.67	$ 1.17
	Diluted - pro forma	$ 1.05	$ 0.49	$ 3.61	$ 1.11

(7) REDEMPTION OF DEBT -

The Company gave notice on June 6, 2003 of its intent to redeem all $115,000,000 of its 5½% Convertible Subordinated Notes due 2006 (the 2006 Notes) at 101.65% of their face amount. Prior to the redemption date of July 7, 2003, holders of $42,536,000 face value of the 2006 Notes converted their notes into 1,008,299 shares of the Company s common stock at the $42.185 per share conversion price. In connection with the redemption, the Company paid a total of $73,661,000 in cash to former holders of the 2006 Notes. The cash redemption payment was funded through a combination of available cash and borrowings under the Company s existing bank credit facility. The Company recorded a pre-tax loss on the redemption of the 2006 Notes of $1.8 million in Accretion and other during the three-month period ended September 30, 2003.

The Company also gave notice on July 7, 2003 of its intent to redeem all $100,000,000 of its 8 3/4% Senior Subordinated Notes due 2007 (the 2007 Notes) at 102.917% of their face amount. On August 6, 2003, the Company paid $102,917,000 in cash to holders of the 2007 Notes. The cash redemption payment was funded through a combination of available cash and borrowings under the Company s existing bank credit facility. The Company recorded a pre-tax loss on the redemption of the 2007 Notes of $4.1 million in Accretion and other during the three-month period ended September 30, 2003.

(8) CONVERSION OF TRUST PREFERRED SECURITIES -

Pogo Trust I, a subsidiary of the Company, called its 6½% Cumulative Quarterly Income Convertible Preferred Securities due 2029 (the Trust Preferred Securities) for redemption on June 3, 2002. Prior to their redemption, holders of 2,997,196 of the 3,000,000 outstanding Trust Preferred Securities converted their Trust Preferred Securities, representing $149,850,000 face value of Trust Preferred Securities, into 6,309,972 shares of the Company s common stock. In connection with the redemption, Pogo Trust I paid a total of $147,000 to former holders of the Trust Preferred Securities. Subsequent to June 3, 2002, there were no Trust Preferred Securities outstanding. The amounts recorded under Minority Interest Dividends and Costs Associated with Preferred Securities of a Subsidiary Trust during the three-month and nine-month periods ended September 30, 2002 principally reflect cumulative dividends and, to a lesser extent, the amortization of issuance expenses related to the offering and sale of the Trust Preferred Securities.

(9) RECENT ACCOUNTING PRONOUNCEMENT -

In April 2003, the FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities (SFAS 149). SFAS 149 amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts and hedging activities under SFAS 133. The amendments set forth in SFAS 149 require that contracts with comparable characteristics be accounted for similarly. SFAS 149 is generally effective for contracts entered into or modified after June 30, 2003 (with limited exceptions) and for hedging relationships designated after June 30, 2003. The guidance is to be applied prospectively only. The adoption of SFAS 149 did not have a material effect on the Company s financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

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

This discussion should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations included in the Company s Annual Report on Form 10-K for the year ended December 31, 2002. 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, 2002, 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.

Results of Operations

Net Income

The Company reported net income for the third quarter of 2003 of $67,660,000 or $1.07 per share ($67,728,000 or $1.06 per share on a diluted basis), compared to net income for the third quarter of 2002 of $31,637,000 or $0.52 per share ($32,665,000 or $0.51 per share on a diluted basis.) For the first nine months of 2003, the Company reported net income of $235,856,000 or $3.79 per share ($237,962,000 or $3.67 per share on a diluted basis), compared to net income for the first nine months of 2002 of $69,280,000 or $1.22 per share ($75,023,000 or $1.17 per share on a diluted basis). The increase in net income during the third quarter of 2003, compared to the third quarter of 2002, was primarily related to increases in the average prices that the Company received for its natural gas, crude oil and condensate production volumes and increased crude oil and condensate production. The increase in net income during the first nine months of 2003, compared to the first nine months of 2002, was related to increases in the average prices that the Company received for its natural gas, crude oil and condensate production volumes and increased natural gas, crude oil and condensate production.

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 share (diluted earnings per share) consider the effect of dilutive securities as set out below. Also presented below are securities that have not been included in the computation of earnings per share in one or more periods because their effect would have been antidilutive. The following shows the components of earnings per share in the respective periods. Amounts are expressed in thousands, except per share amounts.

	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

	Three Months Ended September 30, 2002			Nine Months Ended September 30, 2002		
	Income	Shares	Per Share	Income	Shares	Per Share
Basic earnings per share -	$ 31,637	60,779	$ 0.52	$ 69,280	56,953	$ 1.22
Effect of dilutive securities:						
Options to purchase common shares		949			897	
2006 Notes	1,028	2,726		3,083	2,726	
Trust Preferred Securities [c]				2,660	3,535	
Diluted earnings per share	$ 32,665	64,454	$ 0.51	$ 75,023	64,111	$ 1.17
Antidilutive securities -						
Options to purchase common shares		143	$ 38.00		178	$ 36.65

[a] Reflects income before cumulative effect of change in accounting principle.

[b] The 2006 Notes were redeemed on July 7, 2003. Prior to redemption a portion of the 2006 Notes were converted to 1,008,299 shares of common stock.

[c] The Trust Preferred securities were converted to common stock on June 3, 2002.

Total Revenues

The Company s total revenues for the third quarter of 2003 were $277,915,000, an increase of approximately 34% compared to total revenues of $207,808,000 for the third quarter of 2002. The Company s total revenues for the first nine months of 2003 were $884,268,000,

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an increase of approximately 65% compared to total revenues of $535,103,000 for the first nine months of 2002. The increase in the Company s total revenues for the third quarter and first nine months of 2003, compared to the 2002 periods, resulted from increased oil and gas revenues, which is attributable to higher product prices and crude oil and condensate production volumes. Higher natural gas production volumes also favorably impacted total revenues for the first nine months of 2003, compared to the first nine months of 2002.

Oil and Gas Revenues

The Company s oil and gas revenues for the third quarter of 2003 were $277,067,000, an increase of approximately 36% from oil and gas revenues of $203,919,000 for the third quarter of 2002. The Company s oil and gas revenues for the first nine months of 2003 were $882,464,000, an increase of approximately 66% from oil and gas revenues of $531,457,000 for the first nine months of 2002. The following table reflects an analysis of variances in the Company s oil and gas revenues (expressed in thousands) between the 2003 and 2002 periods.

	3rd Qtr 2003 Compared to 3rd Qtr 2002	9 Months 2003 Compared to 9 Months 2002
Increase (decrease) in oil and gas revenues resulting from variances in:		
Natural gas -		
Price	$ 39,560	$ 127,882
Production	122	22,951
	39,682	150,833
Crude oil and condensate -		
Price	4,332	63,932
Production	29,942	133,108
	34,274	197,040
Natural gas liquids	(808)	3,134
Increase in oil and gas revenues	$ 73,148	$ 351,007

The increase in the Company s oil and gas revenues in the third quarter and first nine months of 2003, compared to the third quarter and first nine months of 2002, is primarily related to increases in the average price that the Company received for its natural gas, crude oil and condensate production and an increase in the Company s crude oil and condensate production volumes. Higher natural gas production volumes also favorably impacted oil and gas revenues for the first nine months of 2003 compared to the first nine months of 2002.

	3rd Quarter		% Change	1st Nine Months		% Change
Comparison of Increases (Decreases) in:	2003	2002		2003	2002	

Natural Gas						
Average prices:						
North America [a]	**$ 4.89**	$ 2.92	**67%**	**$ 5.27**	$ 2.98	**77%**
Kingdom of Thailand [b]	**$ 2.56**	$ 2.15	**19%**	**$ 2.45**	$ 2.19	**12%**
Company-wide average price	**$ 4.21**	$ 2.70	**56%**	**$ 4.45**	$ 2.76	**61%**
Average daily production volumes (MMcf per day) [c]:						
North America	**201.3**	204.3	**(1)%**	**209.6**	200.5	**5%**
Kingdom of Thailand	**83.2**	79.9	**4%**	**87.3**	77.5	**13%**
Company-wide average daily production	**284.5**	284.2	**0%**	**296.9**	278.0	**7%**

(a) North American average prices reflect the impact of the Company s price hedging activity**.** Price hedging activity reduced the average price of the Company s North American natural gas production during the third quarter and first nine months of 2003 by $0.10 per Mcf and $0.21 per Mcf, respectively. Price hedging activity increased the average price of the Company s North American natural gas production during the third quarter and first nine months of 2002 by $0.03 per Mcf and $0.15 per Mcf, respectively.

(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.

(c) MMcf is an abbreviation for million cubic feet.

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	3rd Quarter			1st Nine Months		
	2003	2002	% Change	2003	2002	% Change
Comparison of Increases in:						
Crude Oil and Condensate						
Average prices [a]:						
North America	**$ 27.48**	$ 26.95	**2%**	**$ 29.23**	$ 24.05	**22%**
Kingdom of Thailand	**$ 28.35**	$ 26.76	**6%**	**$ 28.67**	$ 23.87	**20%**
Company-wide average price	**$ 27.80**	$ 26.88	**3%**	**$ 29.04**	$ 23.99	**21%**
Average daily production volumes (Bbls per day) [b]:						
North America [a]	**39,954**	32,419	**23%**	**41,269**	30,060	**37%**
Kingdom of Thailand [c]	**21,410**	17,459	**23%**	**22,097**	16,568	**33%**
Company-wide average daily production	**61,364**	49,878	**23%**	**63,366**	46,628	**36%**
Total Liquid Hydrocarbons						
Company-wide average daily production (Bbls per day)[c]	**65,288**	55,242	**18%**	**67,334**	51,302	**31%**

(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. Price hedging activity reduced the average price of the Company s North American crude oil and condensate production during the third quarter and first nine months of 2003 by $0.66 per barrel and $0.61 per barrel, respectively. The Company had no crude oil and condensate price hedging activity in the comparable 2002 periods. For North American 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 (c) below.

(b) Bbls is an abbreviation for barrels.

(c) 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 121,000 barrels less than it sold in the third quarter of 2003 and 50,000 barrels more than it sold in the first nine months of 2003. The Company produced 100,000 barrels less than it sold in the third quarter of 2002 and 65,000 barrels more than it sold in the first nine months of 2002.

Natural Gas

Thailand Prices. The price that the Company receives under its 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. Effective October 2001, an amendment to the Gas Sales Agreement was negotiated with PTT in which PTT agreed to purchase supplemental gas volumes (currently 85 MMcf per day) over and above the base contractual amount (currently 145 MMcf per day). These supplemental gas volumes over and above the base contractual amounts are sold to PTT at a price equal to 88% of the then-current price calculated under the Gas Sales Agreement for the base contractual volumes. Recently, the Gas Sales Agreement was further amended to extend the period during which supplemental gas volumes would be provided to PTT through December 31, 2007. The price for the supplemental gas volumes was not changed and remains 88% of the then-current price calculated under the Gas Sales Agreement as previously described.

Production. The increase in the Company s natural gas production during the first nine months of 2003, compared to the first nine months of 2002, was primarily related to successful development programs on the Company s Los Mogotes Field, Madden Field and Gulf of Mexico properties, including its Main Pass 61/62 Field, and increased Thailand production from the Benchamas Field, partially offset by natural production declines at other properties. The slight increase in the Company s natural gas volumes during the third quarter of 2003 compared to the third quarter of 2002 was primarily related to increased production from the Los Mogotes, Main Pass 61/62 and Benchamas Fields, offset by reduced production from the Company s Madden Unit and natural production declines at other properties. During the second quarter of 2003, the operator of the Company s Madden Field announced that it had shut in the Lost Cabin gas plant to study the gathering system and make necessary repairs. Subsequent to the announcement of the shut-in, the operator restored limited production to the plant. The shut-in has effectively reduced the Company s net production from the Madden Field by approximately 11 MMcf per day as of September 30, 2003. The operator has announced that the infrastructure repair is underway, with full production expected to be restored by year-end 2003.

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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 have been stored on the FSO and sold as economic quantities are accumulated. 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 Malaysian TAPIS crude, and are denominated in U.S. dollars.

Production. The increase in the Company s crude oil and condensate production during the third quarter and first nine months of 2003, compared to the third quarter and first nine months of 2002, resulted primarily from the success of the Company s development program in the Main Pass Blocks 61/62 Field and increased crude oil and condensate production at its Benchamas Field in the Kingdom of Thailand. These increases were partially offset by 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. When such crude oil is sold, the cost of the crude oil and the related sales revenue are recognized in the income statement. 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. As of September 30, 2003, the Company had approximately 252,000 net barrels stored on board the FPSO and FSO.

NGL Production. 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 extracted from natural gas production. The decrease in NGL revenues for the third quarter of 2003, compared with the third quarter of 2002, primarily related to a decrease in volumes extracted, which was only partially offset by an increase in NGL prices received ($14.82 per barrel in the third quarter of 2002 versus $18.02 per barrel in the third quarter of 2003). The increase in NGL revenues for the first nine months of 2003, compared with the first nine months of 2002, primarily related to an increase in NGL prices received ($14.23 per barrel in the first nine months of 2002 versus $19.65 per barrel in the first nine months of 2003), partially offset by a decrease in volumes extracted.

Costs and Expenses

Comparison of Increases (Decreases) in:	3rd Quarter 2003	3rd Quarter 2002	% Change	Nine Months 2003	Nine Months 2002	% Change
Lease Operating Expenses						
North America	**$ 21,611,000**	$ 20,837,000	**4%**	**$ 65,064,000**	$ 60,368,000	**8%**
Kingdom of Thailand	**$ 11,275,000**	$ 8,897,000	**27%**	**$ 32,395,000**	$ 27,494,000	**18%**
Total Lease Operating Expenses	**$ 32,886,000**	$ 29,734,000	**11%**	**$ 97,459,000**	$ 87,862,000	**11%**
General and Administrative Expenses	**$ 16,936,000**	$ 14,445,000	**17%**	**$ 45,362,000**	$ 36,815,000	**23%**

Exploration Expenses	**$ 1,432,000**	$ 2,508,000	**(43)%**	**$ 5,091,000**	$ 3,684,000	**38%**
Dry Hole and Impairment Expenses	**$ 4,568,000**	$ 8,179,000	**(44)%**	**$ 10,666,000**	$ 16,674,000	**(36)%**
Depreciation, Depletion and Amortization (DD&A) Expenses	**$ 79,688,000**	$ 73,960,000	**8%**	**$ 244,454,000**	$ 213,708,000	**14%**
DD&A rate	**$ 1.27**	$ 1.29	**(2)%**	**$ 1.28**	$ 1.34	**(4)%**
Mcfe sold [(a)]	**62,936,645**	57,240,000	**10%**	**191,052,649**	159,539,000	**20%**
Production and Other Taxes	**$ 8,084,000**	$ 5,254,000	**54%**	**$ 27,269,000**	$ 12,994,000	**110%**
Accretion and Other	**$ 8,468,000**	$ 2,133,000	**297%**	**$ 16,364,000**	$ 2,314,000	**607%**
Interest						
Charges	**$ (10,255,000)**	$ (14,364,000)	**(29)%**	**$ (36,934,000)**	$ (43,452,000)	**(15)%**
Income	**$ 446,000**	$ 404,000	**10%**	**$ 1,380,000**	$ 1,316,000	**5%**
Capitalized	**$ 4,246,000**	$ 5,933,000	**(28)%**	**$ 12,377,000**	$ 19,445,000	**(36)%**
Minority Interest - Dividends and Costs	**$**	$	**N/A**	**$**	$ (4,140,000)	**(100)%**
Foreign Currency Transaction Gain (Loss)	**$ 587,000**	$ (458,000)	**(228)%**	**$ 1,149,000**	$ 873,000	**32%**
Income Tax Expense	**$ (53,217,000)**	$ (31,473,000)	**69%**	**$ (175,553,000)**	$ (65,814,000)	**167%**

[(a)] Mcfe stands for thousands of cubic feet equivalent

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Lease Operating Expenses

The increase in North American lease operating expenses for the third quarter and first nine months of 2003, compared to the respective 2002 periods, is related primarily to new and higher production from the Company s onshore properties and additional Gulf of Mexico platforms added during 2002 and, to a lesser extent, increased expenses at the recently expanded Lost Cabin gas plant in the Madden Unit.

The increase in lease operating expenses in the Kingdom of Thailand for the third quarter and first nine months of 2003, compared to the respective 2002 periods, primarily related to costs associated with operating the four additional platforms which were added to the Gulf of Thailand during the second half of 2002 and the resulting increase in operating expenses as additional wells were subsequently brought on production. In accordance with generally accepted accounting principles, the portion of lifting costs that is attributable to crude oil and condensate stored on the FPSO and FSO is treated as an inventoried cost until that crude oil and condensate is sold. At the time the crude oil and condensate is sold, those inventoried lifting costs are recognized as lease operating expenses. Variances in production, sales and operating costs will result in variances in the amount of lease operating expense that is currently recognized as expense and the amount recorded as product inventory to be recognized in subsequent periods. A substantial portion of the Company s lease operating expenses in the Kingdom of Thailand relates 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 $3,665,000 and $10,876,000 (net to the Company s interest) of the Company s Thailand lease operating expenses for the third quarters and first nine months, respectively, of 2003 and 2002. The Company currently expects these lease payments to remain relatively constant at approximately $14,500,000 per year (net to the Company s interest) for the next several years.

Notwithstanding the overall increase in lease operating expenses, on a per unit of production basis, the Company s total lease operating expenses have continued to decrease from an average of $0.55 per Mcfe for the first nine months of 2002 to $0.51 per Mcfe for the first nine months of 2003. Total lease operating expenses remained a constant $0.53 per Mcfe, on a per unit of production basis, for the third quarters of 2002 and 2003.

General and Administrative Expenses

The increase in general and administrative expenses for the third quarter and first nine months of 2003 compared with the respective 2002 periods, related to increases in professional fees, higher benefit expenses, costs related to the start of operations in the Company s Budapest office, increased insurance costs and expenses related to the Company s decision, announced last year, to expense stock-based compensation. The Company s general and administrative expenses, on a per unit of production basis, increased slightly to $0.27 per Mcfe for the third quarter of 2003 and $0.24 per Mcfe for the first nine months of 2003, compared to $0.26 per Mcfe and $0.23 per Mcfe for the respective periods of 2002.

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 first nine months of 2003, compared to the first nine months of 2002, resulted primarily from a rebate of a delay rental ($1,327,000 net to the Company) that was paid by the Company s Thai subsidiary to the Kingdom of Thailand, which was returned in the first quarter of 2002 when certain contractual obligations under the Company s Thai license were satisfied. There was no comparable rebate in the 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. During the third quarter and first nine months of 2003, the Company drilled two and four unsuccessful exploratory wells, respectively and the Company drilled one and three unsuccessful exploratory wells during the third quarter and first nine months of 2002, respectively. The Company will drill several exploratory wells in the fourth quarter of 2003 that, if unsuccessful, could have a material adverse effect on the Company s results of operation. Generally accepted accounting principles require that if the expected future cash flows of the Company s reserves on a property fall below the related carrying value recorded on the Company s books, these properties must be impaired and written down to their respective 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 such impairments could have a material negative non-cash impact on the Company s results of operations and financial position. During the third quarters and first nine months of 2003 and 2002, the Company recognized miscellaneous impairments on various non-producing prospects and leases.

Depreciation, Depletion and Amortization (DD&A) 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 2003 compared to the respective 2002 periods resulted primarily from an increase in the Company s natural gas and liquid hydrocarbon production, partially offset by a decrease in the Company s composite DD&A rate.

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The decrease in the composite DD&A rate for all of the Company s producing fields for the third quarter and first nine months of 2003, compared to the respective 2002 periods, resulted primarily from an increased percentage of the Company s production coming from fields that have DD&A rates lower than the Company s recent historical composite rate (principally certain Gulf of Mexico properties and the Benchamas Field) and a corresponding decrease in the percentage of the Company s production coming from fields that have DD&A rates higher than the Company s recent historical composite DD&A rate.

Production and Other Taxes

The increase in production and other taxes during the third quarter and first nine months of 2003, compared to the respective 2002 periods, relates to increased severance taxes due to higher onshore production volumes and prices. The increase is also related to the recognition during the third quarter and first nine months of 2003 of $4,593,000 and $8,819,000, respectively, of the Special Remunitory Benefit (SRB) obligation related to the Company s Kingdom of Thailand concession. No comparable SRB expenses were incurred in 2002. 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. It is currently anticipated that the Company will continue to pay SRB for the foreseeable future.

Accretion and Other

The increase in accretion and other expense during the third quarter and first nine months of 2003, compared to the comparable 2002 periods, relates to the inclusion of expense related to the accretion of the Company s asset retirement obligation under a new accounting standard adopted on January 1, 2003, for which no comparable expense was incurred in the third quarter or first nine months of 2002. The increase in accretion and other expense during third quarter of 2003, compared to the third quarter of 2002, was primarily related to losses incurred on the extinguishment of debt on the 2006 Notes and 2007 Notes during the third quarter of 2003 and the result of a write down of the cost of the Company s tubular inventory stock. The increase in accretion and other expense during the first nine months of 2003, compared to the first nine months of 2002, was also the result of a write down of the cost of the Company s tubular inventory stock during the first quarter of 2003 for which no comparable write down expenses were incurred in the first nine months of 2002 and the result of increased valuation allowances on certain of the Company s receivables (including the Company s Enron receivable) during the second quarter of 2003.

Interest

Interest Charges. The decrease in the Company s interest charges for the third quarter and first nine months of 2003, compared with the respective 2002 periods, resulted primarily from a decrease in the average amount of the Company s outstanding debt, partially offset by an increase in the average interest rate on the outstanding debt due to the repayment of approximately $139,000,000 of lower interest rate senior debt under the Credit Facility during the first nine months of 2003.

Interest Income. The increase in the Company s interest income for the third quarter and first nine months of 2003, compared to the comparable 2002 periods, resulted primarily from an increase in the amount of cash and cash equivalents temporarily invested. The cash and cash equivalents on the Company s balance sheet are primarily held by the Company s international subsidiaries for future investment overseas, in part due to the negative tax effects that would result from the repatriation of these funds.

Capitalized Interest. Interest costs related to financing oil and gas projects in progress are capitalized until the projects are substantially complete and ready for their intended use, provided such projects are evaluated as successful. The decrease in capitalized interest for the third quarter and first nine months of 2003, compared to the comparable 2002 periods, resulted primarily from a decrease in the amount of capital expenditures subject to interest capitalization during the third quarter and first nine months of 2003 (approximately $185,000,000 and $192,000,000, respectively), compared to the third quarter and first nine months of 2002 (approximately $380,000,000 and $379,000,000, respectively). These changes were only partially offset by an increase in the Company s weighted average borrowing rate. The weighted average borrowing rate increased due to the Company s repayment of lower rate senior debt during the first nine months of 2003. A substantial percentage of the Company s capitalized interest relates to unevaluated properties acquired in the North Central acquisition and capital expenditures for the construction of platforms in the Gulf of Thailand, as well as several development projects in the Gulf of Mexico.

Minority Interest Dividends and Costs Associated with Mandatorily Redeemable Convertible Preferred Securities of a Subsidiary Trust

Pogo Trust I, a business trust in which the Company owned all of the issued common securities, issued $150,000,000 of Trust Preferred Securities on June 2, 1999. Pogo Trust I called the Trust Preferred Securities for redemption on June 3, 2002. Prior to their redemption, holders of 2,997,196 of the 3,000,000 outstanding Trust Preferred Securities converted their Trust Preferred Securities, representing over $149,850,000 face value of Trust Preferred Securities, into 6,309,972 shares of the Company s common stock. In connection with the redemption, Pogo Trust I paid a total of $147,000 to former holders of the Trust Preferred Securities. Subsequent to June 3, 2002, there were no Trust Preferred Securities outstanding. The amounts recorded under Minority Interest Dividends and Costs Associated with Preferred Securities of a Subsidiary Trust during the first nine months of 2002 principally reflect cumulative dividends and, to a lesser extent, the amortization of issuance expenses related to the offering and sale of the Trust Preferred Securities.

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Foreign Currency Transaction Gain (Loss)

The foreign currency transaction gains reported in the third quarter and first nine months of 2003 and the first nine months of 2002, together with the foreign currency transaction loss reported in the third quarter of 2002, resulted primarily from the fluctuation against the U.S. dollar of cash and other monetary assets and liabilities denominated in Thai Baht related to the Company s Thai operations. During the first nine months of 2003, the Thai Baht U.S. dollar daily average exchange rate fluctuated between 40.0 and 43.1 Baht to the U.S. dollar. The Company cannot predict what the Thai Baht to U.S. dollar exchange rate will be in the future. As of October 13, 2003, the Company was not a party to any financial instrument that was intended to constitute a foreign currency hedging arrangement.

Exposure from market rate fluctuations related to activities in Hungary, where the Company s functional currency is the legal tender in Hungary (currently the Forint), is not material at this time.

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 and first nine months of 2003, compared to the comparable 2002 periods, resulted primarily from increased pre-tax income during the 2003 periods, partially offset by a decrease in the Company s effective tax rate during the 2003 periods. The Company s consolidated effective tax rate for the third quarters of 2003 and 2002 was 44% and 50%, respectively. The Company s consolidated effective tax rate for the first nine months of 2003 and 2002 was 42% and 49%, respectively. The lower effective tax rates are the result of a greater percentage of the Company s pre-tax income being derived from its U.S. operations in 2003, which is taxed at a rate lower than its Thailand operations, relative to the percentage of the Company s pre-tax income from Thailand operations.

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. 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, 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 for the ARC and its accumulated depreciation.

Liquidity and Capital Resources

The Company s cash flow provided by operating activities for the first nine months of 2003 was $579,462,000. This compares to cash flow from operating activities of $348,299,000 in first nine months of 2002. The resulting increases are attributable to the reasons described under Results of Operations above. Cash flow from operating activities in the first nine months of 2003 was more than adequate to fund $260,655,000 in cash expenditures for capital and exploration projects for the nine-month period ended September 30, 2003. The Company also repaid approximately

$315,566,000 of net debt obligations (including the redemptions discussed below) and paid $9,340,000 of dividends on the Company s common stock during the first nine months of 2003. As of September 30, 2003, the Company had cash and cash equivalents of $161,601,000 (including $153,652,000 in international subsidiaries which the Company intends to reinvest in its foreign operations) and long-term debt obligations of $371,000,000 (excluding debt discount of $1,826,000) with no repayment obligations until 2006. On July 7, 2003, the Company satisfied all $115,000,000 of its outstanding 5 1/2% Convertible Subordinated Notes due 2006, for 1,008,299 shares of common stock and $73,661,000 in cash. On August 6, 2003, the Company redeemed all $100,000,000 of its 8 3/4% Senior Subordinated Notes due 2007 for $102,917,000 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 April 21, 2003, the Company s lenders redetermined the borrowing base under its Credit Agreement at $600,000,000. The available borrowing capacity under the Credit Agreement is currently $515,000,000. As of October 13, 2003, the Company had an outstanding balance of $30,000,000 under its Credit Agreement.

Future Capital and Other Expenditure Requirements

The Company s capital and exploration budget for 2003, which does not include any amounts that may be expended for the purchase of proved reserves or any interest which may be capitalized resulting from projects in progress, has been established by the Company s Board of Directors at $355,000,000, of which approximately $225,000,000 was incurred in the nine-month period ended September 30, 2003. The Company currently anticipates that its available cash and cash investments, 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, its authorized capital budget, and future 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 certain covenants

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contained in its debt instruments, the general economic and regulatory climate and other factors deemed relevant by the Company s Board of Directors.

Recent Accounting Pronouncements and Developments

In April 2003, the FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities (SFAS 149). SFAS 149 amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts and hedging activities under SFAS 133. The amendments set forth in SFAS 149 require that contracts with comparable characteristics be accounted for similarly. SFAS 149 is generally effective for contracts entered into or modified after June 30, 2003 (with limited exceptions) and for hedging relationships designated after June 30, 2003. The guidance is to be applied prospectively only. The adoption of SFAS 149 did not have a material effect on the Company s financial statements.

The Company has been made aware that an issue has arisen regarding the application of provisions of SFAS No. 141, Business Combinations and SFAS No. 142, Goodwill and Other Intangible Assets (SFAS 142) to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS 142 requires registrants to reclassify costs associated with mineral rights, including both proved and unproved leasehold acquisition costs, as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs. Historically, the Company and other oil and gas companies have included the cost of these oil and gas leasehold interests as part of oil and gas properties and provided the disclosures required by SFAS No. 69, Disclosures about Oil and Gas Producing Activities (SFAS 69). Also under consideration is whether SFAS 142 requires registrants to provide the additional disclosures prescribed by SFAS 142 for intangible assets for costs associated with mineral rights.

If it is ultimately determined that SFAS 142 requires the Company to reclassify costs associated with mineral rights from property and equipment to intangible assets, the Company currently believes that its results of operations and financial condition would not be affected, since such intangible assets would continue to be depleted and assessed for impairment in accordance with existing successful efforts accounting rules and impairment standards. In addition, costs associated with mineral rights would continue to be characterized as oil and gas property costs in our required disclosures under SFAS 69.

At September 30, 2003, we had undeveloped leaseholds of approximately $113 million that would be classified on our balance sheet as intangible undeveloped leaseholds and developed leaseholds of approximately $957 million (net of accumulated depletion) that would be classified as intangible developed leaseholds if we applied the interpretation currently being discussed.

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, for non-trading purposes only, 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

Natural Gas

As of September 30, 2003, 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 on the NYMEX for each trading day of a particular contract 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.

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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, 2003, 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:				
October 2003 - December 2003	3,680	$ 3.85	$ 5.00	$ (822,000)
October 2003 - December 2003	1,840	$ 4.25	$ 7.00	$ 56,000
Crude Oil Contracts (Barrels)				
Collar Contracts:				
October 2003 - December 2003	920,000	$ 25.00	$ 30.00	$ (313,000)

(a) MMBtu means million British Thermal Units.

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 13, 2003, 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, 2003:

	2003	2004	2005	2006	2007	Thereafter	Total	Fair Value
Long-Term Debt:								
Variable Rate	$ 0	$ 0	$ 0	$ 21,000	$ 0	$ 0	$ 21,000	$ 21,000
Average Interest Rate				3.18%			3.18%	
Fixed Rate	$ 0	$ 0	$ 0	$ 0	$ 0	$ 350,000	$ 350,000	$ 373,375
Average Interest Rate						9.16%	9.16%	

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 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 natural 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 dollars, the dollar is the functional currency for the Company s operations in the Kingdom of Thailand. As of October 13, 2003, 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 legal tender in Hungary (currently the Forint), 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.

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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 4. Submission of Matters to Vote of Security Holders

None

ITEM 6. Exhibits and Reports on Form 8-K.

(A) Exhibits

10.1 The Third Amendment to the Gas Sales Agreement dated November 7^{TH}, 1995 Between PTT Public Company Limited and Chevron Offshore (Thailand) Limited, Thaipo Limited, Palang Sophon Limited and B8/32 Partners Limited, Dated Effective as of October 1, 2001

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.

(B) Reports on Form 8-K

During the quarter for which this report is filed, the following reports on Form 8-K were filed:

Report dated October 14, 2003 (Items 7, 9, and 12 (furnished material only; not filed for purposes of Section 18 of the Securities Exchange Act or any other purpose)).

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 15, 2003