POGO PRODUCING CO
Form 10-Q
May 05, 2003

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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 March 31, 2003

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

Registrant's number of common shares outstanding as of April 30, 2003: **61,834,933**

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Statements of Income (Unaudited)

	Three Months Ended March 31, 2003	Three Months Ended March 31, 2002
	(Expressed in thousands, except per share amounts)	
Revenues:		
Oil and gas	$ 309,867	$ 142,297
Other	887	613
Total	310,754	142,910
Operating Costs and Expenses:		
Lease operating	33,089	28,472
General and administrative	13,372	11,542
Exploration	1,832	(176)
Dry hole and impairment	2,178	4,995
Depreciation, depletion and amortization	80,419	65,806
Production and other taxes	8,954	2,811
Accretion and other	3,076	181
Total	142,920	113,631
Operating Income	167,834	29,279
Interest:		
Charges	(13,695)	(14,588)
Income	387	378
Capitalized	4,014	6,653
Minority Interest Dividends and costs associated with preferred securities of a subsidiary trust		(2,502)
Foreign Currency Transaction Gain	226	672
Income Before Taxes and Cumulative Effect of Change in Accounting Principle	158,766	19,892
Income Tax Expense	(66,123)	(10,867)
Income Before Cumulative Effect of Change in Accounting Principle	92,643	9,025
Cumulative Effect of Change in Accounting Principle	(4,166)	
Net Income	$ 88,477	$ 9,025
Earnings Per Common Share		
Basic:		
Income before cumulative effect of change in accounting principle	$ 1.52	$ 0.17

	Three Months Ended March 31,	
Cumulative effect of change in accounting principle	(0.07)	
Net income	$ 1.45	$ 0.17
Diluted:		
Income before cumulative effect of change in accounting principle	$ 1.44	$ 0.17
Cumulative effect of change in accounting principle	(0.07)	
Net income	$ 1.37	$ 0.17
Dividends Per Common Share	$ 0.05	$ 0.03
Weighted Average Number of Common Shares and Potential Common Shares Outstanding:		
Basic	61,157	53,750
Diluted	65,128	54,487

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Balance Sheets (Unaudited)

	March 31, 2003	December 31, 2002
	(Expressed in thousands, except share amounts)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 144,838	$ 134,449
Accounts receivable	140,246	101,807
Other receivables	30,008	14,634
Deferred income tax	2,250	20,041
Inventories Product	5,399	2,501
Inventories Tubulars	7,913	9,406
Other	1,917	4,818
Total current assets	332,571	287,656
Property and Equipment:		
Oil and gas, on the basis of successful efforts accounting		
Proved properties	3,503,335	3,396,669
Unevaluated properties	137,250	141,094
Other, at cost	27,525	26,626

	March 31, 2003	December 31, 2002
	3,668,110	3,564,389
Accumulated depreciation, depletion and amortization		
Oil and gas	(1,446,648)	(1,389,976)
Other	(16,515)	(15,364)
	(1,463,163)	(1,405,340)
Property and equipment, net	2,204,947	2,159,049
Other Assets:		
Deferred income tax	2,416	2,416
Debt issue costs	10,889	11,368
Foreign value added taxes receivable	14,865	13,908
Other	19,887	17,196
	48,057	44,888
	$ 2,585,575	$ 2,491,593

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Balance Sheets (Unaudited)

	March 31, 2003	December 31, 2002
	(Expressed in thousands, except share amounts)	
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable operating activities	$ 57,274	$ 41,102
Accounts payable investing activities	70,347	68,963
Accrued interest payable	15,124	11,096
Income taxes payable	59,649	15,527
Accrued payroll and related benefits	3,039	3,011
Deferred income tax	5,324	5,324
Price hedge contracts	6,968	2,433
Other	6,821	2,229
Total current liabilities	224,546	149,685

	March 31, 2003	December 31, 2002
Long-Term Debt	587,988	722,903
Deferred Income Tax	520,122	526,897
Asset Retirement Obligation	65,409	
Other Liabilities and Deferred Credits	18,177	14,324
Total liabilities	1,416,242	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, 61,379,292 and 61,061,888 shares issued, respectively	61,379	61,062
Additional capital	830,882	822,526
Retained earnings	287,577	202,155
Accumulated other comprehensive income (loss)	(8,795)	(6,249)
Treasury stock (55,359 shares), at cost	(1,710)	(1,710)
Total shareholders' equity	1,169,333	1,077,784
	$ 2,585,575	$ 2,491,593

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows (Unaudited)

	Three Months Ended March 31,	
	2003	2002
	(Expressed in thousands)	
Cash Flows from Operating Activities:		
Cash received from customers	$ 294,921	$ 115,219
Operating, exploration, and general and administrative expenses paid	(49,734)	(42,624)
Interest paid	(9,001)	(10,252)
Income taxes paid	(5,000)	
Income taxes received		25,103
Value added taxes paid	(957)	(2,360)

	Three Months Ended March 31,	
Price hedge contracts	(10,267)	11,672
Other	4,013	(692)
Net cash provided by operating activities	223,975	96,066
Cash Flows from Investing Activities:		
Capital expenditures	(82,243)	(87,491)
Proceeds from the sale of properties		14
Net cash used in investing activities	(82,243)	(87,477)
Cash Flows from Financing Activities:		
Borrowings under senior debt agreements	118,999	183,999
Payments under senior debt agreements	(254,000)	(189,000)
Payments of cash dividends on common stock	(3,055)	(1,611)
Payments of preferred dividends of a subsidiary trust		(2,438)
Payment of debt issue costs	(100)	(111)
Proceeds from exercise of stock options	6,767	6,300
Net cash used in financing activities	(131,389)	(2,861)
Effect of exchange rate changes on cash	46	(37)
Net increase in cash and cash equivalents	10,389	5,691
Cash and cash equivalents at the beginning of the year	134,449	94,294
Cash and cash equivalents at the end of the period	$ 144,838	$ 99,985
Reconciliation of net income to net cash provided by operating activities:		
Net income	$ 88,477	$ 9,025
Adjustments to reconcile net income to net cash provided by operating activities		
Cumulative effect of change in accounting principle	4,166	
Minority interest		2,502
Accretion and other	4,101	(672)
Losses from the sales of properties	62	262
Depreciation, depletion and amortization	80,419	65,806
Dry hole and impairment	2,178	4,995
Interest capitalized	(4,014)	(6,653)
Price hedge contracts	1,119	2,662
Deferred income taxes	17,001	7,546
Change in operating assets and liabilities	30,466	10,593
Net cash provided by operating activities	$ 223,975	$ 96,066

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

Consolidated Statements of Shareholders' Equity (Unaudited)

	For the Three Months Ended March 31,					
	2003			2002		
	Shareholders' Equity		Compre-hensive Income	Shareholders' Equity		Compre-hensive Income
	Shares	Amount		Shares	Amount	
	(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	
Stock options exercised	317,404	317		336,636	336	
Issued at end of period	61,379,292	61,379		54,027,463	54,027	
Additional Capital:						
Balance at beginning of year		822,526			659,227	
Stock options exercised		8,356			7,175	
Balance at end of period		830,882			666,402	
Retained Earnings:						
Balance at beginning of year		202,155			102,019	
Net income		88,477	$ 88,477		9,025	$ 9,025
Dividends ($0.05 and $0.03 per common share in 2003 and 2002, respectively)		(3,055)			(1,611)	
Balance at end of period		287,577			109,433	
Accumulated Other Comprehensive Income (Loss):						
Balance at beginning of year		(6,249)			10,272	
Change in fair value of price hedge contracts		(9,550)	(9,550)		(5,534)	(5,534)
Reclassification adjustment for losses (gains) included in net income		7,004	7,004		(5,856)	(5,856)
Balance at end of period		(8,795)			(1,118)	
Comprehensive Income (Loss)			$ 85,931			$ (2,365)
Treasury Stock:						
Balance at beginning of year	(55,359)	(1,710)		(15,575)	(324)	

	For the Three Months Ended March 31,			
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	61,323,933		54,011,888	
Total Shareholders' Equity		$ 1,169,333		$ 828,420

See accompanying notes to consolidated financial statements.

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POGO PRODUCING COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (Unaudited)

(1) GENERAL INFORMATION

The consolidated financial statements included herein have been prepared by Pogo Producing Company (the "Company") without audit and include all adjustments (of a normal and recurring nature), which are, in the opinion of management, necessary for the fair presentation of interim results. The interim results are not necessarily indicative of results for the entire year. 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 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 March 31, 2003			Three Months Ended March 31, 2002		
	Income(a)	Shares	Per Share	Income(a)	Shares	Per Share
Basic earnings per share	$ 92,643	61,157	$ 1.52	$ 9,025	53,750	$ 0.17
Effect of dilutive securities:						
Options to purchase common shares		1,245			737	
2006 Notes	1,028	2,726				
Diluted earnings per share	$ 93,671	65,128	$ 1.44	$ 9,025	54,487	$ 0.17
Antidilutive securities						
Options to purchase common shares		69	$ 40.92		262	$ 33.82
2006 Notes				$ 1,028	2,726	$ 0.38
Trust Preferred Securities (b)				$ 1,584	6,316	$ 0.25

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

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

(3) HEDGING ACTIVITIES

As of March 31, 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 months ended March 31, 2003 and 2002, the Company recognized a pre-tax loss of $10,775,000 ($7,004,000 after taxes) and a pre-tax gain of $9,009,000 ($5,856,000 after taxes),

respectively, from its price hedge contracts which are included in oil and gas revenues. Unrealized losses on derivative instruments of $2,546,000, net of deferred taxes of $1,371,000, have been reflected as a component of other comprehensive income for the three months ended March 31, 2003. Based on the fair market value of the hedge contracts as of March 31, 2003, the Company would reclassify additional pre-tax losses of approximately $13,531,000 (approximately $8,795,000 after taxes) from accumulated other comprehensive income (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 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, over-the-counter quotations, volatility and the time value of options. Further details related to the Company's hedging activities as of March 31, 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:				
April 2003 December 2003	11,000	$ 3.85	$ 5.00	$ (5,272,000)
April 2003 December 2003	5,500	$ 4.25	$ 7.00	$ 181,000
Crude Oil Contracts (Barrels)				
Collar Contracts:				
April 2003 December 2003	2,750,000	$ 25.00	$ 30.00	$ (1,877,000)

(a) MMBtu means million British Thermal Units.

(4) CHANGE IN ACCOUNTING PRINCIPLE

The Company has adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," ("SFAS 143") as of January 1, 2003, which 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 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.

The Company recorded a liability representing expected future costs associated with site reclamation, facilities dismantlement, and plugging and abandonment of wells as follows (in thousands):

Initial ARO as of January 1, 2003	$	63,643
Liabilities incurred during the three months ended March 31, 2003		571
Accretion expense		1,195
Balance of ARO as of March 31, 2003	$	65,409

For the three months ended March 31, 2003 the Company recognized depreciation expense related to its ARO of $972,000. 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. Had SFAS 143 been applied retroactively in the three months ended March 31, 2002, the Company's net income and earnings per share would have been as follows (expressed in 000's, except per share amounts):

	As Reported		Pro forma	
Net Income	$	9,025	$	8,906
Earnings per share:				
Net income				
Basic	$	0.17	$	0.17
Diluted	$	0.17	$	0.16

(5) GEOGRAPHIC INFORMATION

Financial information by geographic segment is presented below:

	Three Months Ended March 31,	
	2003	2002
	(Expressed in thousands)	

	Three Months Ended March 31,	
Revenues:		
United States	$ 234,568	$ 101,695
Kingdom of Thailand	76,184	41,217
Other	2	(2)
Total	$ 310,754	$ 142,910
Operating Income (Loss):		
United States	$ 126,874	$ 13,673
Kingdom of Thailand	41,721	16,120
Other	(761)	(514)
Total	$ 167,834	$ 29,279

(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 is 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 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 no Stock Awards during the three-month period ended March 31, 2003.

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-month periods ending March 31, 2003 and 2002 (in thousands of dollars, except per share amounts):

	Three Months Ended March 31,	
	2003	**2002**
Net income, as reported	$ 88,477	$ 9,025
Add: Employee stock-based compensation expense, net of related tax effects, included in net income, as reported		
Deduct: Total employee stock-based compensation expense, determined under fair value method for all awards, net of related tax effects	(1,523)	(1,199)
Net income, pro forma	$ 86,954	$ 7,826

	Three Months Ended March 31,			
Earnings per share:				
Income before the cumulative effect of change in accounting principle				
Basic as reported	$	1.52	$	0.17
Basic pro forma	$	1.49	$	0.15
Diluted as reported	$	1.44	$	0.17
Diluted pro forma	$	1.42	$	0.14
Net income				
Basic as reported	$	1.45	$	0.17
Basic pro forma	$	1.42	$	0.15
Diluted as reported	$	1.37	$	0.17
Diluted pro forma	$	1.35	$	0.14

(7) CONVERSION OF TRUST PREFERRED SECURITIES

Pogo Trust I, a subsidiary of the Company, called its 6 1/2% 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 first quarter 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.

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 first quarter of 2003 of $88,477,000 or $1.45 per share ($93,671,000 or $1.37 per share on a diluted basis), compared to net income for the first quarter of 2002 of $9,025,000 or $0.17 per share (on both a basic and a diluted basis). The increase in net income was primarily related to increases in the average prices that the Company received for its natural gas, crude oil and condensate production volumes, in addition to increased production from the Company's onshore, Gulf of Mexico and Thailand properties.

Earnings per common share are based on the weighted average number of common shares outstanding for the first quarter of 2003 of 61,157,000 (65,128,000 on a diluted basis), compared to 53,750,000 (54,487,000 on a diluted basis) for the first quarter of 2002. The increase in the weighted average number of common shares outstanding for the first quarter of 2003, compared to the first quarter of 2002, resulted primarily from the conversion of 2,997,196 of the 3,000,000 outstanding Trust Preferred Securities into 6,309,972 shares of the Company's common stock on June 3, 2002 and to a much lesser extent, the issuance of shares upon the exercise of stock options pursuant to the Company's stock option plans and stock issued as compensation. The earnings per share computation on a diluted basis for the first quarter of 2003 reflects additional shares of common stock issuable upon the assumed conversion of the Company's 5 1/2% Convertible Subordinated Notes due 2006 (the "2006 Notes") and the elimination of related interest requirements, as adjusted for applicable federal income taxes. In addition, for both periods, the number of common shares outstanding in the diluted computations are adjusted to include dilutive shares that are assumed to have been issued by the Company in connection with outstanding options under its Incentive Plans, less treasury shares that are assumed to have been purchased by the Company from the option proceeds.

Total Revenues

The Company's total revenues for the first quarter of 2003 were $310,754,000, an increase of approximately 117% compared to total revenues of $142,910,000 for the first quarter of 2002. The increase in the Company's total revenues for the first quarter of 2003, compared to the first quarter of 2002, resulted primarily from increased oil and gas revenues, which is attributable to higher product prices and higher natural gas, crude oil and condensate production.

Oil and Gas Revenues

The Company's oil and gas revenues for the first quarter of 2003 were $309,867,000, an increase of approximately 118% from oil and gas revenues of $142,297,000 for the first quarter of 2002. The

following table reflects an analysis of variances in the Company's oil and gas revenues (expressed in thousands) between 2003 and 2002.

	1st Qtr 2003 Compared to 1st Qtr 2002
Increase in oil and gas revenues resulting in variances in:	
Natural gas	
Price	$ 46,641
Production	16,974
	63,615
Crude oil and condensate	
Price	45,427
Production	53,207
	98,634
Natural gas liquids	5,321
Increase in oil and gas revenues	$ 167,570

The increase in the Company's oil and gas revenues in the first quarter of 2003, compared to the first quarter of 2002, is related to increases in the average price that the Company received for its natural gas, crude oil and condensate production and to a lesser extent an increase in the Company's natural gas, crude oil and condensate production volumes.

	1st Qtr 2003	1st Qtr 2002	% Change 2003 to 2002
Comparison of Increases in:			
Natural Gas			

	1st Qtr 2003	1st Qtr 2002	% Change 2003 to 2002
Average prices			
North America (a)	**$ 5.58**	$ 2.80	**99%**
Kingdom of Thailand (b)	**$ 2.32**	$ 2.32	**0%**
Company-wide average price	**$ 4.63**	$ 2.67	**73%**
Average daily production volumes			
(MMcf per day):			
North America (a)	**215.8**	190.9	**13%**
Kingdom of Thailand	**89.0**	73.1	**22%**
Company-wide average daily production	**304.8**	264.0	**15%**

(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 first quarter of 2003 by $0.39 per Mcf and increased the average price by $0.52 per Mcf for the first quarter of 2002. "MMcf" is an abbreviation for million cubic feet.

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(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.

	1st Qtr 2003	1st Qtr 2002	% Change 2003 to 2002
Comparison of Increases in:			
Crude Oil and Condensate			
Average prices (a)			
North America	**$ 32.32**	$ 20.24	**60%**
Kingdom of Thailand	**$ 31.78**	$ 19.67	**62%**
Company-wide average price	**$ 32.14**	$ 20.04	**60%**
Average daily production volumes			
(Bbls per day):			
North America (a)	**39,992**	27,045	**48%**
Kingdom of Thailand (b)	**23,091**	16,519	**40%**
Company-wide average daily production	**63,083**	43,564	**45%**
Total Liquid Hydrocarbons			
Company-wide average daily production (Bbls per day)(b)	**67,602**	47,175	**43%**

(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 by $0.91 per barrel during the first quarter of 2003. 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 (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 268,000 barrels and 167,000 barrels more than it sold in the first quarters of 2003 and 2002, respectively.

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. An amendment to the Gas Sales Agreement provided that for certain volumes which the Company produces in excess of the base contractual amount (currently 145 MMcf per day) the price that the Company receives from PTT will be equal to 88% of the then-current price calculated under its Gas Sales Agreement.

Production. The increase in the Company's natural gas production during the first quarter of 2003, compared to the first quarter of 2002, was primarily related to successful development programs on the Company's Madden Unit and Gulf of Mexico properties, including its Mississippi Canyon Blocks

661/705 and Main Pass 61/62 Fields, and increased Thailand production from the Benchamas Field, partially offset by natural production declines at other properties.

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 were 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 Malaysian TAPIS crude, and are denominated in U.S. dollars. As discussed further under "Costs and Expenses, Lease Operating Expenses," the Company records all crude oil held in the FPSO and the FSO at the end of an accounting period as inventory held at cost. When such crude oil is sold, usually during the following month, the difference between the cost of the crude oil and the sales revenue is recognized in the income statement.

Production. The increase in the Company's crude oil and condensate production during the first quarter of 2003, compared to the first quarter of 2002, resulted primarily from the continuing success of the Company's development program in the Main Pass Blocks 61/62 Field, its Ewing Bank Block 871 Field and its Mississippi Canyon 661/705 Field and, to a lesser extent, 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. 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 March 31, 2003, the Company had approximately 470,000 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 that are extracted from natural gas production. The increase in NGL revenues for the first quarter of 2003, compared with the first quarter of 2002, primarily related to an increase in NGL prices received from $11.55 per barrel in the first quarter of 2002 to $22.31 per barrel in the first quarter of 2003, and, to a lesser extent, an increase in volumes extracted (primarily from the Company's Mississippi Canyon Blocks 661/705 Field gas production.)

Costs and Expenses

		1st Quarter 2003		1st Quarter 2002	% Change 2003 to 2002
Comparison of Increases (Decreases) in:					
Lease Operating Expenses					
North America	**$**	**23,454,000**	$	19,955,000	**18%**
Kingdom of Thailand	**$**	**9,635,000**	$	8,517,000	**13%**
Total Lease Operating Expenses	**$**	**33,089,000**	$	28,472,000	**16%**
General and Administrative Expenses	**$**	**13,372,000**	$	11,542,000	**16%**
Exploration Expenses	**$**	**1,832,000**	$	(176,000)	**N/A**
Dry Hole and Impairment Expenses	**$**	**2,178,000**	$	4,995,000	**(56)%**
Depreciation, Depletion and Amortization (DD&A) Expenses	**$**	**80,419,000**	$	65,806,000	**22%**
DD&A rate	**$**	**1.29**	$	1.35	**(4)%**
Mcfe sold (a)		**62,326,000**		48,234,000	**29%**
Production and Other Taxes	**$**	**8,954,000**	$	2,811,000	**219%**
Accretion and Other	**$**	**3,076,000**	$	181,000	**1599%**
Interest					
Charges	**$**	**(13,695,000)**	$	(14,588,000)	**(6)%**
Interest Income	**$**	**387,000**	$	378,000	**2%**
Capitalized Interest Expense	**$**	**4,014,000**	$	6,653,000	**(40)%**
Minority Interest Dividends and Costs	**$**		$	2,502,000	**(100)%**
Foreign Currency Transaction Gain	**$**	**226,000**	$	672,000	**(66)%**
Income Tax Expense	**$**	**(66,123,000)**	$	(10,867,000)	**508%**

Lease Operating Expenses

The increase in North American lease operating expenses for the first quarter of 2003, compared to the first quarter of 2002, 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 first quarter of 2003, compared to the first quarter of 2002, primarily related to costs associated with operating the six additional platforms added to the Gulf of Thailand during 2002. 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 $3,390,000 (net to the Company's interest) of the Company's Thailand lease operating expenses for the first quarters 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 $0.58 per Mcfe for the first quarter of 2002 to $0.52 per Mcfe for the first quarter of 2003.

General and Administrative Expenses

The increase in general and administrative expenses for the first quarter of 2003 compared with the first quarter of 2002, primarily related to normal increases in compensation and concomitant benefit expense (which, was negatively impacted in 2003 by the lower return on the Company's retirement plan assets and by increased medical costs) and, to a lesser extent, increases in professional fees and insurance costs. Notwithstanding the overall increase in general and administrative expenses, on a per unit of production basis, the Company's general and administrative expenses declined to $0.21 per Mcfe in the first quarter of 2003 from $0.25 per Mcfe in the first quarter 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 quarter of 2003, compared to the first quarter of 2002, resulted primarily from a rebate of a delay rental in 2002 ($1,327,000 net to the Company) that was paid by the Company's Thai subsidiary to the Kingdom of Thailand, which was returned when certain contractual obligations under the Company's Thai license were satisfied. There was no comparable rebate in the first quarter 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 first quarter of 2003 the Company drilled one unsuccessful exploratory well. No unsuccessful exploratory wells were drilled in the first quarter of 2002. 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 reserves must be impaired and written down to the property's fair value. Depending on market conditions, including the prices for oil and natural gas, and the results of operations, a similar test may be conducted at any time to determine whether impairments are appropriate. Depending on the results of this test, 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 first quarters of 2003 and 2002, 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 first quarter of 2003 compared to the first quarter of 2002 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.

The decrease in the composite DD&A rate for all of the Company's producing fields for the first quarter of 2003, compared to the first quarter of 2002, resulted primarily from an increased percentage of the Company's production coming from fields that have DD&A rates that are 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 that are higher than the Company's recent historical composite DD&A rate.

Production and Other Taxes

The increase in production and other taxes during the first quarter of 2003, compared to the first quarter of 2002, relates primarily to increased severance taxes due to higher onshore production volumes and prices, and recognition of $2,374,000 of the Special Remunitory Benefit (SRB) obligation related to the Company's Kingdom of Thailand concession. No comparable SRB expense was 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 first quarter of 2003, compared to the first quarter of 2002, relates primarily 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 and a write down of the value to the Company's tubular inventory stock, for which no comparable expenses were incurred in 2002.

Interest

Interest Charges. The decrease in the Company's interest charges for the first quarter of 2003, compared to the first quarter of 2002, 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 its repayment of $135,001,000 of its lower interest rate senior debt under the Credit Facility during the first quarter of 2003.

Interest Income. The increase in the Company's interest income for the first quarter of 2003, compared to the first quarter of 2002, 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 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 change in capitalized interest for the first quarter of 2003, compared to the first quarter of 2002, resulted primarily from a decrease in the amount of capital expenditures subject to interest capitalization during 2003 (approximately $206,000,000), compared to 2002 (approximately $377,000,000). These changes were only partially offset by an increase in the computed rate incurred by the Company and applied to such capital expenditures to arrive at the total amount of capitalized interest. The computed rate increased due to the Company's repayment of lower rate senior debt during the quarter. A substantial percentage of the Company's capitalized interest related to unevaluated properties acquired in the North Central acquisition and capital expenditures for the development of the Benchamas Field 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 quarter 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. No such expenses were incurred in the first quarter of 2003.

Foreign Currency Transaction Gain (Loss)

The foreign currency transaction gain reported in the first quarter of 2003 and the first 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 quarter of 2003, the Thai Baht U.S. dollar daily average exchange rate fluctuated between 42.2 and 43.5 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 April 30, 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 first quarter of 2003, compared to the first quarter of 2002, resulted primarily from increased pre-tax income during 2003, partially offset by a decrease in the Company's effective tax rate during the 2003 period. The Company's consolidated effective tax rate for the first quarters of 2003 and 2002 was 42% and 55%, respectively The lower effective tax rate is the result of a lower percentage of the Company's pre-tax income being derived from its Thailand operations during the comparative periods, which is taxed at a rate higher than the U.S. statutory rate, relative to the percentage of its pre-tax income from U.S. operations.

Cumulative Effect of Change in Accounting Principle

The Company has adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," ("SFAS 143") as of January 1, 2003, which 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 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 cash flow provided by operating activities for the first quarter of 2003 was $223,975,000. This compares to cash flow from operating activities of $96,066,000 in the first quarter of 2002. The resulting increases are attributable to the reasons described under "Results of Operations", above. Cash flow from operating activities in the first quarter of 2003 was more than adequate to fund $82,243,000 in cash expenditures for capital and exploration projects for the three-month period. The Company also repaid approximately $135,001,000 of debt obligations and paid $3,055,000 of dividends on the Company's common stock during the first quarter of 2003. As of March 31, 2003, the Company had cash and cash equivalents of $144,838,000 (including $131,577,000 in international subsidiaries which the Company intends to reinvest in its foreign operations) and long-term debt obligations of $589,986,000 (excluding debt discount of $1,998,000) with no repayment obligations until 2006. The Company may determine to repurchase 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 11, 2003, the Company's Master Banker's Acceptance Agreement was terminated. At that time, there was no outstanding balance. In addition, the Company's borrowing base under its Credit Agreement was redetermined by its lenders at $600,000,000 effective April 21, 2003. The available borrowing capacity under the Credit Agreement is currently $515,000,000. As of April 30, 2003, the Company had no outstanding balance 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, was established by the Company's Board of Directors at $320,000,000. 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, 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 contained in its 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

Natural Gas

As of March 31, 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.

The estimated fair value of these transactions is based upon various factors that include closing exchange prices on the NYMEX, over-the-counter quotations, volatility and the time value of options. Further details related to the Company's hedging activities as of March 31, 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:				
April 2003 December 2003	11,000	$ 3.85	$ 5.00	$ (5,272,000)
April 2003 December 2003	5,500	$ 4.25	$ 7.00	$ 181,000
Crude Oil Contracts (Barrels)				
Collar Contracts:				
April 2003 December 2003	2,750,000	$ 25.00	$ 30.00	$ (1,877,000)

(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 April 30, 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 March 31, 2003:

	2003	2004	2005	2006	2007	Thereafter	Total	Fair Value
Long-Term Debt:								
Variable Rate	$ 0	$ 0	$ 0	$ 24,987	$ 0	$ 0	$ 24,987	$ 25,000
Average Interest Rate				2.14%			2.14%	
Fixed Rate	$ 0	$ 0	$ 0	$ 115,000	$ 100,000	$ 350,000	$ 565,000	$ 597,025
Average Interest Rate				5.50%	8.75%	9.16%	8.34%	

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 dollars, the dollar is the functional currency for the Company's operations in the Kingdom of Thailand. As of April 30, 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.

Within the 90 days prior to the date of this report, 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-14 under the Securities Exchange Act of 1934, as amended. 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 significant changes in the Company's internal controls or in other factors that could significantly affect internal controls subsequent to the date of the evaluation referred to above.

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POGO PRODUCING COMPANY AND SUBSIDIARIES

Part II. Other Information

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

(A)

Exhibits

99.1 Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 dated May 5, 2003, by Paul G. Van Wagenen, Chairman, President and Chief Executive Officer of Pogo Producing Company.

99.2 Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 dated May 5, 2003, by James P. Ulm II, Senior Vice President and Chief Financial Officer of Pogo Producing Company.

(B)

Reports on Form 8-K

Report filed on January 22, 2003, relating to the date of the Company's 2003 Annual Meeting of Shareholders and also relating to the press release dated January 21, 2003 regarding the Company's 2002 results (Items 5 and 9 and attaching three exhibits under Item 7).

Report filed on April 22, 2003, relating to the press release dated April 22, 2003 regarding the Company's first quarter 2003 results (Items 9 and 12 and attaching three exhibits under Item 7).

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: May 5, 2003

POGO PRODUCING COMPANY AND SUBSIDIARIES

CERTIFICATIONS

I, Paul G. Van Wagenen, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Pogo Producing Company,

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

   c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: May 5, 2003

/s/ PAUL G. VAN WAGENEN

Paul G. Van Wagenen
Chairman, President and Chief
Executive Officer

POGO PRODUCING COMPANY AND SUBSIDIARIES

I, James P. Ulm, II, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Pogo Producing Company;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

   c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: May 5, 2003

/s/ JAMES P. ULM, II

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

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