POGO PRODUCING CO
Form 10-Q
October 31, 2002

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, 2002

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 Incorporation or Organization)	**(I.R.S. Employee 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 ¨

Registrant s number of common shares outstanding as of October 28, 2002: 60,988,914

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,	
	2002	2001	2002	2001
	(Expressed in thousands, except per share amounts)			
Revenues:				
Oil and gas	$ 203,919	$ 139,677	$ 531,457	$ 468,002
Pipeline sales		1,950	78	10,649
Gains on sales and other	3,889	1,908	3,568	4,140
Total	207,808	143,535	535,103	482,791
Operating Costs and Expenses:				
Lease operating	34,988	31,939	100,856	87,462
Pipeline operating and natural gas purchases	2,133	1,838	2,314	10,258
General and administrative	14,445	11,281	36,815	29,139
Exploration	2,508	5,013	3,684	17,447
Dry hole and impairment	8,179	3,053	16,674	26,097
Depreciation, depletion and amortization	73,960	55,754	213,708	146,286
Total	136,213	108,878	374,051	316,689
Operating Income	71,595	34,657	161,052	166,102
Interest:				
Charges	(14,364)	(15,119)	(43,452)	(41,411)
Income	404	690	1,316	2,686
Capitalized	5,933	9,324	19,445	24,153
Minority Interest Dividends and costs associated with preferred securities of a subsidiary trust		(2,501)	(4,140)	(7,499)
Foreign Currency Transaction Gain (Loss)	(458)	338	873	(668)
Income Before Taxes	63,110	27,389	135,094	143,363
Income Tax Expense	(31,473)	(11,786)	(65,814)	(56,835)
Net Income	$ 31,637	$ 15,603	$ 69,280	$ 86,528
Earnings Per Common Share				
Basic	$ 0.52	$ 0.29	$ 1.22	$ 1.72
Diluted	$ 0.51	$ 0.28	$ 1.17	$ 1.57
Dividends Per Common Share	$ 0.03	$ 0.03	$ 0.09	$ 0.09
Weighted Average Number of Common Shares and Potential Common Shares Outstanding:				
Basic	60,779	53,613	56,953	50,239

Diluted	64,454	60,480	64,111	60,068

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (Unaudited)

	September 30, 2002	December 31, 2001
	(Expressed in thousands, except share amounts)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 122,669	$ 94,294
Accounts receivable	75,383	52,440
Other receivables	26,604	32,159
Federal income tax receivable	3,454	27,441
Deferred income tax	24,267	25,712
Inventories Product	4,023	3,129
Inventories Tubulars	9,500	8,430
Price hedge contracts	5,228	34,275
Other	7,782	1,970
Total current assets	278,910	279,850
Property and Equipment:		
Oil and gas, on the basis of successful efforts accounting		
Proved properties	3,239,680	2,956,673
Unevaluated properties	200,730	257,158
Pipelines, at cost	775	775
Other, at cost	24,711	21,638
	3,465,896	3,236,244
Accumulated depreciation, depletion and amortization		
Oil and gas	(1,318,839)	(1,133,560)
Pipelines	(739)	(739)
Other	(13,729)	(11,217)
	(1,333,307)	(1,145,516)
Property and equipment, net	2,132,589	2,090,728
Other Assets:		
Deferred income tax	5,526	13,359
Debt issue costs	14,026	15,565
Foreign value added taxes receivable	10,960	6,200
Price hedge contracts	2,211	
Other	18,976	20,706
	51,699	55,830
	$ 2,463,198	$ 2,426,408

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (Unaudited)

	September 30, 2002	December 31, 2001
	(Expressed in thousands, except share amounts)	
Liabilities and Shareholders Equity		
Current Liabilities:		
Accounts payable operating activities	$ 34,428	$ 34,962
Accounts payable investing activities	70,383	94,523
Accrued interest payable	15,075	11,450
Foreign income taxes payable	4,474	7,966
Accrued dividends associated with preferred securities of a subsidiary trust		813
Accrued payroll and related benefits	3,032	2,670
Deferred income tax	5,324	3,875
Price hedge contracts	2,458	
Other	1,352	1,892
Total current liabilities	136,526	158,151
Long-Term Debt	739,985	794,990
Deferred Income Tax	529,670	488,639
Price Hedge Contracts	731	
Deferred Credits	14,074	14,657
Total liabilities	1,420,986	1,456,437
Minority Interest:		
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust, net of unamortized issue expenses		145,086
Shareholders Equity:		
Preferred stock, $1 par; 4,000,000 shares authorized		
Common stock, $1 par; 200,000,000 shares authorized, 60,885,291 and 53,690,827 shares issued, respectively	60,885	53,691
Additional capital	817,911	659,227
Retained earnings	166,235	102,019
Accumulated other comprehensive income (loss)	(2,495)	10,272
Treasury stock (15,575 shares), at cost	(324)	(324)
Total shareholders equity	1,042,212	824,885
	$ 2,463,198	$ 2,426,408

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)

	Nine Months Ended September 30,	
	2002	**2001**
	(Expressed in thousands)	
Cash Flows from Operating Activities:		
Cash received from customers	$ 506,759	$ 510,915
Operating, exploration, and general and administrative expenses paid	(154,713)	(159,823)
Interest paid	(38,122)	(29,919)
Federal income taxes paid	(9,288)	(31,115)
Federal income taxes received	25,884	
Value added taxes (paid) received	(4,760)	1,028
Price hedge contracts	20,449	8,808
Other	2,090	1,527
Net cash provided by operating activities	348,299	301,421
Cash Flows from Investing Activities:		
Capital expenditures	(276,392)	(280,819)
Purchase of proved reserves		(2,714)
Proceeds from the sale of properties and subsidiaries	4,255	20,001
Acquisition of NORIC, net of $21,235 cash acquired		(323,476)
Net cash used in investing activities	(272,137)	(587,008)
Cash Flows from Financing Activities:		
Proceeds from the issuance of new debt		200,000
Borrowings under senior debt agreements	529,995	1,063,992
Payments under senior debt agreements	(585,000)	(872,000)
Payments of cash dividends on common stock	(5,064)	(4,438)
Payments of preferred dividends of a subsidiary trust	(4,850)	(7,312)
Payment of debt issue costs	(182)	(8,720)
Payment of North Central senior debt acquired		(78,600)
Proceeds from exercise of stock options	17,399	6,699
Redemption of Trust Preferred Securities	(147)	
Net cash (used in) provided by financing activities	(47,849)	299,621
Effect of exchange rate changes on cash	62	(1,134)
Net increase in cash and cash equivalents	28,375	12,900
Cash and cash equivalents at the beginning of the year	94,294	81,510
Cash and cash equivalents at the end of the period	$ 122,669	$ 94,410
Reconciliation of net income to net cash provided by operating activities:		
Net income	$ 69,280	$ 86,528
Adjustments to reconcile net income to net cash provided by operating activities		
Minority interest	4,140	7,499
Foreign currency transaction (gains) losses	(873)	668
Gains from the sales of properties	(3,100)	(4,487)
Depreciation, depletion and amortization	213,708	146,286
Dry hole and impairment	16,674	26,097

Interest capitalized	(19,445)	(24,153)
Price hedge contracts	13,016	5,342
Deferred federal income taxes	60,017	48,588
Change in operating assets and liabilities	(5,118)	9,053
Net cash provided by operating activities	$ 348,299	$ 301,421

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,					
	2002			2001		
	Shareholders Equity			Shareholders Equity		
	Shares	Amount	Comprehensive Income	Shares	Amount	Comprehensive Income
	(Expressed in thousands, except share amounts)					
Common Stock:						
$1.00 par-200,000,000 shares authorized						
Balance at beginning of year	53,690,827	$ 53,691		40,659,591	$ 40,660	
Shares issued for Trust Preferred Securities conversion	6,309,972	6,310				
Stock options exercised	845,437	845		337,264	337	
Shares issued as compensation	39,055	39		37,656	38	
Shares issued for acquisition of NORIC				12,615,816	12,615	
Issued at end of period	60,885,291	60,885		53,650,327	53,650	
Additional Capital:						
Balance at beginning of year		659,227			298,885	
Shares issued for Trust Preferred Securities conversion		138,715				
Stock options exercised		18,845			6,922	
Shares issued as compensation		1,124			894	
Shares issued for acquisition of NORIC					351,729	
Balance at end of period		817,911			658,430	
Retained Earnings:						
Balance at beginning of year		102,019			20,112	
Net income		69,280	$ 69,280		86,528	$ 86,528
Dividends ($0.09 per common share)		(5,064)			(4,438)	
Balance at end of period		166,235			102,202	
Accumulated Other Comprehensive Income (Loss):						
Balance at beginning of year		10,272			(1,062)	
Exchange gains on Canadian currency					2,253	2,253
Unrealized gain (loss) on price hedge contracts		(7,936)	(7,936)		23,067	23,067
Cumulative effect of change in accounting principle					(2,438)	(2,438)
Reclassification adjustment for losses included in net income		(4,831)	(4,831)		(1,765)	(1,765)
Balance at end of period		(2,495)			20,055	
Comprehensive Income			$ 56,513			$ 107,645
Treasury Stock:						

Balance at beginning of year	(15,575)	(324)	(15,575)	(324)
Activity during the period				
Balance at end of period	(15,575)	(324)	(15,575)	(324)
Common Stock Outstanding, at the End of the Period	60,869,716		53,634,752	
Total Shareholders Equity		$ 1,042,212		$ 834,013

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 with current year presentation. Refer to the Consolidated Statements of Shareholders Equity for an analysis of Other Comprehensive Income, which was $56,513,000 and $107,645,000, respectively, for the nine months ended September 30, 2002 and 2001 ($30,522,000 and $25,786,000, respectively, for the three months ended September 30, 2002 and 2001). 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, 2001.

(2) INCOME TAXES -

Where the Company s present intention is to reinvest the unremitted earnings of its foreign subsidiaries in foreign operations, the Company does not provide for U.S. income taxes on unremitted earnings of those foreign subsidiaries. Unremitted earnings of foreign subsidiaries for which U.S. income taxes have not been provided are approximately $79,167,000 at September 30, 2002. It is not practical to determine the amount of U.S. income taxes that would be payable upon remittance of such earnings.

(3) 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.

(4) HEDGING ACTIVITIES -

The Company adopted Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133), effective January 1, 2001. SFAS 133 requires that, as of the date of initial adoption, the difference between the market value of derivative instruments and the previous carrying amount of these derivatives be recorded in net income or other comprehensive income, as appropriate, as the cumulative effect of a change in accounting principle. Based on interpretive guidance issued during the first quarter of 2001, the Company determined that the cumulative effect of adopting SFAS 133 should be recorded in other comprehensive income. As such, effective January 1, 2001, the Company recorded an unrealized loss of $2,438,000, net of deferred taxes of $1,313,000, in other comprehensive income. Unrealized losses on derivative instruments arising during the nine months ended September 30, 2002 of $7,936,000, net of deferred taxes of $4,273,000, have been reflected as a component of other comprehensive income. Based on the fair market value of the hedge contracts as of September 30, 2002, the Company would reclassify additional pre-tax losses of approximately $3,839,000 (approximately $2,495,000 net of taxes) from accumulated other comprehensive income to net income.

As of September 30, 2002, the Company held various derivative instruments. In addition to the remaining term of the natural gas floor contracts entered into late in 2000, the Company at the end of the third quarter and early in the fourth quarter of 2002, 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 fluctuations associated with the forecasted sale of its oil and gas production. 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 credit worthiness of its counterparties.

The gas hedging transactions are generally settled based upon the average of the reporting settlement prices on the NYMEX for the last three trading days of a particular contract month. The oil hedging transactions are generally settled based on the average of the reporting settlement prices for West Texas Intermediate on the NYMEX for each trading day of a particular contract month. For any particular floor contract, 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. The Company is not required to make any payment in connection with the settlement of a floor contract. For any particular collar transaction, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price for such transaction, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price of such transaction.

POGO PRODUCING COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) (Continued)

(4) HEDGING ACTIVITIES (Continued)

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 September 30, 2002, are as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price		Fair Market Value
		Floor	Ceiling	
Natural Gas Contracts (MMBtu) (a)				
Floor Contract:				
October 2002 - December 2002	6,440	$ 4.00		$ 1,618,000
Collar Contracts:				
January 2003 - December 2003	1,825	$ 3.85	$ 5.00	$ 301,000
Crude Oil Contracts (Barrels)				
Collar Contracts:				
October 2002 - December 2003	2,742,000	$ 25.00	$ 30.00	$ 2,331,000

(a) MMBtu means million British Thermal Units.

In October 2002, the Company entered into additional natural gas and crude oil option agreements (collars) to establish floor and ceiling prices on anticipated future natural gas and crude oil production. The Company has designated these contracts as cash flow hedges. Further details related to these hedging activities are as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price	
		Floor	Ceiling
Natural Gas Contracts (MMBtu)			
Collar Contracts:			
January 2003 - December 2003	12,775	$ 3.85	$ 5.00
Crude Oil Contracts (Barrels)			
Collar Contracts:			
October 2002 - December 2003	1,828,000	$ 25.00	$ 30.00

POGO PRODUCING COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) (Continued)

(5) BUSINESS SEGMENT INFORMATION -

Financial information by operating segment is presented below:

	Company	Oil and Gas	Pipelines	Other
	(Expressed in thousands)			
Revenues:				
For the three months ended September 30, 2002				
United States	$ 146,215	$ 142,500	$	$ 3,715
Kingdom of Thailand	61,535	61,419		116
Other	58			58
Total	$ 207,808	$ 203,919	$	$ 3,889
For the three months ended September 30, 2001				
United States	$ 92,135	$ 88,658	$ 1,950	$ 1,527
Kingdom of Thailand	50,568	50,563		5
Canada and other	832	456		376
Total	$ 143,535	$ 139,677	$ 1,950	$ 1,908
For the nine months ended September 30, 2002				
United States	$ 382,099	$ 378,642	$ 78	$ 3,379
Kingdom of Thailand	152,946	152,815		131
Other	58			58
Total	$ 535,103	$ 531,457	$ 78	$ 3,568
For the nine months ended September 30, 2001				
United States	$ 341,225	$ 326,869	$ 10,649	$ 3,707
Kingdom of Thailand	136,639	136,575		64
Canada and other	4,927	4,558		369
Total	$ 482,791	$ 468,002	$ 10,649	$ 4,140
Operating Income (Loss):				
For the three months ended September 30, 2002				
United States	$ 42,341	$ 38,661	$ (36)	$ 3,716
Kingdom of Thailand	29,572	29,456		116
Other	(318)	(1,331)		1,013
Total	$ 71,595	$ 66,786	$ (36)	$ 4,845
For the three months ended September 30, 2001				
United States	$ 14,741	$ 13,270	$ (56)	$ 1,527
Kingdom of Thailand	21,317	21,312		5
Canada and other	(1,401)	(1,777)		376
Total	$ 34,657	$ 32,805	$ (56)	$ 1,908

For the nine months ended September 30, 2002				
United States	$ 97,519	$ 94,318	$ (178)	$ 3,379
Kingdom of Thailand	64,806	64,675		131
Other	(1,273)	(1,331)		58
Total	$ 161,052	$ 157,662	$ (178)	$ 3,568
For the nine months ended September 30, 2001				
United States	$ 114,052	$ 110,531	$ (186)	$ 3,707
Kingdom of Thailand	62,091	62,027		64
Canada and other	(10,041)	(10,410)		369
Total	$ 166,102	$ 162,148	$ (186)	$ 4,140

POGO PRODUCING COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) (Continued)

(6) EARNINGS PER SHARE -

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

	Three Months Ended September 30, 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 (a)				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

	Three Months Ended September 30, 2001			Nine Months Ended September 30, 2001		
	Income	Shares	Per Share	Income	Shares	Per Share
Basic earnings per share	$ 15,603	53,613	$ 0.29	$ 86,528	50,239	$ 1.72
Effect of dilutive securities:						
Options to purchase common shares		551			787	
2006 Notes				3,083	2,726	
Trust Preferred Securities (a)	1,584	6,316		4,753	6,316	
Diluted earnings per share	$ 17,187	60,480	$ 0.28	$ 94,364	60,068	$ 1.57
Antidilutive securities						
Options to purchase common shares		1,231	$ 27.08		313	$ 31.00
2006 Notes	1,028	2,726	0.38			

(a) The Trust Preferred securities were converted on June 3, 2002.

(7) RECENT ACCOUNTING PRONOUNCEMENTS -

The Financial Accounting Standards Board has issued a new pronouncement, Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations (SFAS 143). SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. The Company will adopt this standard as required on

January 1, 2003. Adoption of the standard will result in recording a cumulative effect of a change in accounting principle to earnings in the period of adoption. The Company has not yet fully quantified the financial statement impact from adoption of this new standard.

POGO PRODUCING COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) (Continued)

(7) RECENT ACCOUNTING PRONOUCEMENTS (Continued)

The Financial Accounting Standards Board has issued a new pronouncement, Statement of Financial Accounting Standards No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections (SFAS 145). SFAS 145 provides guidance for income statement classification of gains and losses on extinguishment of debt and accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. The Company adopted this standard as required on May 15, 2002. Implementation of the new standard had no impact upon adoption and is not currently expected to have a material financial statement impact on the Company**.**

The Financial Accounting Standards Board has issued a new pronouncement, Statement of Financial Accounting Standards No. 146, Accounting for Exit of Disposal Activities (SFAS 146). SFAS 146 addresses significant issues regarding the recognition, measurement and reporting of costs that are associated with exit and disposal activities, including restructuring activities that are currently accounted for pursuant to the guidance set forth in EITF Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity . The Company will adopt this standard as required on January 1, 2003. Adoption of the standard is not expected to have a material financial statement impact on the Company.

(8) ACQUISITION -

On March 14, 2001, the merger of the Company and NORIC Corporation was consummated. As a result of the merger, the Company acquired all of the outstanding capital stock of North Central Oil Company, which was the principal asset of NORIC. North Central was an independent domestic oil and gas exploration and production company. The merger was accounted for using the purchase method of accounting. Accordingly, the purchase price was allocated to the net assets acquired based upon their estimated fair market values at the date of acquisition. Commencing March 14, 2001, North Central s operations are consolidated with the operations of the Company. Pursuant to the merger agreement among the Company and NORIC and certain NORIC shareholders dated as of November 19,2000, former shareholders received 12,615,816 shares of the Company s common stock and approximately $344,711,000 in cash. In addition, the Company repaid all $78,600,000 principal amount of North Central s existing bank debt upon closing. The sources of funds used in connection with the merger included cash on hand at the Company and NORIC and borrowings under the Company s revolving credit agreement.

The following summary presents unaudited pro forma consolidated results of operations as if the acquisition had occurred at the beginning of 2001. The pro forma results are for illustrative purposes only and include adjustments in addition to the pre-acquisition historical results of North Central, such as increased depreciation, depletion and amortization expense resulting from the allocation of fair market value to oil and gas properties acquired and increased interest expense related to acquisition debt. The unaudited pro forma financial information is not necessarily indicative of the operating results that would have occurred had the acquisition been consummated at that date, nor are they necessarily indicative of future operating results.

	Nine Months Ended September 30, 2001
Revenues	$ 545,771
Net income	$ 102,922
Earnings per share	
Basic	$ 1.92
Diluted	$ 1.75

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, 2001. 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, 2001, 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.

On March 14, 2001, the merger of Pogo Producing Company (the Company) and NORIC Corporation (NORIC) was consummated. As a result of the merger, the Company acquired all of the outstanding capital stock of North Central Oil Corporation (North Central), an independent domestic oil and gas exploration and production company, which was the principal asset of NORIC. The merger was accounted for using the purchase method of accounting. Commencing March 14, 2001, the results of North Central s operations are consolidated with the Company s. Pursuant to the merger agreement among the Company, NORIC and certain NORIC shareholders dated as of November 19, 2000, former shareholders of NORIC received 12,615,816 shares of the Company s common stock and approximately $344,711,000 in cash. In addition, at the closing the Company repaid all $78,600,000 principal amount of North Central s existing bank debt. The sources of funds used in connection with the merger included cash on hand at the Company and NORIC and borrowings under the Company s revolving credit agreement.

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 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.

Application of Critical Accounting Policies

The discussion and analysis of the Company s financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in Note 1 to our consolidated financial statements included in the Company s Annual Report on Form 10-K for the year ended December 31, 2001. We have identified below policies that are of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. We analyze our estimates, including those related to oil and gas revenues, bad debts, oil and gas properties, marketable securities, income taxes, derivatives, contingencies and litigation, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of the Company s financial statements:

Successful Efforts Method Of Accounting

The Company accounts for its oil and gas exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and gas leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but such costs are charged to expense if and when the well is determined not to have found reserves in commercial quantities. In most cases, a gain or loss is recognized for sales of producing properties.

The application of the successful efforts method of accounting requires management s judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. Wells may be completed that are assumed to be productive and actually deliver oil and gas in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. On occasion, wells are drilled which have targeted geologic structures that are both developmental and exploratory in nature, and in such instances an allocation of costs is required to properly account for the results. Delineation seismic costs incurred to select development locations within an oil and gas field are typically treated as development costs and capitalized, but often these seismic programs extend beyond the proved reserve area and therefore management must estimate the portion of seismic costs to expense as exploratory. The evaluation of oil and gas leasehold acquisition costs requires management s judgment to estimate the fair value of exploratory costs related to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

The successful efforts method of accounting can have a significant impact on the operational results reported when the Company enters a new exploratory area in hopes of finding oil and gas reserves. The initial exploratory wells may be unsuccessful and the associated costs will be expensed as dry hole costs. Seismic costs can be substantial which will result in additional exploration expenses when incurred.

Reserve Estimates

The Company s estimates of oil and gas reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulations by governmental agencies, and assumptions governing future oil and gas prices, future operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves may be later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of expected oil and gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company s oil and gas properties and/or the rate of depletion of such oil and gas properties. Actual production, revenues and expenditures with respect to the Company s reserves will likely vary from estimates, and such variances may be material.

Impairment Of Oil and Gas Properties

The Company reviews its producing oil and gas properties for impairment on an annual basis and whenever events and circumstances indicate a decline in the recoverability of their carrying value. The Company estimates the expected future cash flows from its oil and gas properties and compares these future cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and gas properties to its fair value in the current period. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected. The Company recognized significant impairment expense due to poor reservoir performance at one of its Gulf of Mexico properties in the first quarter of 2001, and has recognized other less significant impairment expenses related to other properties in subsequent periods. Given the complexities associated with oil and gas reserve estimates and the history of price volatility in the oil and gas markets, events may arise that will require the Company to record an impairment of its oil and gas properties and there can be no assurance that such impairments will not be required in the future.

Fair Values Of Derivative Instruments

The estimated fair values of the Company s derivative instruments are recorded on the Company s consolidated balance sheet. Historically, substantially all of the Company s derivative instruments represent cash flow hedges of the price of future oil and natural gas production. Therefore, while fair values of such hedging instruments must be estimated at the end of each reporting period, the related changes in such fair values are not included in the Company s consolidated results of operations, to the extent they are expected to offset the future cash flows from oil and natural gas production. Instead, the changes in fair value of hedging instruments are recorded directly to shareholders equity until the hedged oil or natural gas quantities are produced.

The estimation of fair values for the Company s hedging derivatives requires substantial judgment. The Company estimates the fair values of its derivatives on a monthly basis using an option-pricing model. To utilize the option-pricing model, the Company obtains the forecasts of future NYMEX oil and gas prices from independent third parties. The estimated future prices are compared to the prices fixed by the hedge agreements, and the resulting estimated future cash inflows (outflows) over the lives of the hedges are discounted using the Company s current borrowing rates under its revolving credit facility. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts, regional price differentials and interest rates. Currently, all of the Company s derivative instruments are hedges of the price of crude oil and natural gas production. The Company is not involved in any derivative trading activities.

Business Combinations

The Company grew substantially last year through the acquisition of North Central. As stated earlier, this acquisition was accounted for using the purchase method of accounting, and recent accounting pronouncements require that all future acquisitions be accounted for using the purchase method.

Under the purchase method, the acquiring company adds to its balance sheet the estimated fair values of the acquired company s assets and liabilities. Any excess of the purchase price over the fair values of the tangible and intangible net assets acquired is recorded as goodwill. As of January 1, 2002, the accounting for goodwill has changed. In prior years, goodwill was amortized. As of January 1, 2002, goodwill and other intangibles with an indefinite useful life are no longer amortized, but instead are assessed for impairment at least annually. The Company has never recorded any goodwill in connection with the acquisition of any assets. However, there can be no assurance that the Company may not do so in the future.

There are various assumptions made by the Company in determining the fair values of an acquired company s assets and liabilities. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of the oil and gas properties acquired. To determine the fair values of these properties, the Company prepares estimates of oil, natural gas and natural gas liquid (NGL) reserves. These estimates are based on work performed by the Company s engineers and outside petroleum reservoir consultants. The judgments associated with the estimation of reserves are described earlier in this section. The fair value of the estimated reserves acquired in a business combination is then calculated based on the Company s estimates of future oil, natural gas and NGL prices. The Company s estimates of future prices are based on its own analysis of pricing trends. These estimates are based on current data obtained with regard to regional and worldwide supply and demand dynamics, such as economic growth forecasts. They are also based on industry data regarding natural gas storage availability, drilling rig activity, changes in delivery capacity and trends in regional pricing differentials. Future price forecasts from independent third parties are also taken into account in arriving at the Company s own pricing estimates. The Company s estimates of future prices are applied to the estimated reserve quantities acquired to arrive at estimated future net revenues. For estimated proved reserves, the future net revenues are then discounted to derive a fair value for such reserves. The Company also applies these same general principles in arriving at the fair value of unproved reserves acquired in a business combination. These unproved reserves are generally classified as either probable or possible reserves. Because of their very nature, probable and possible reserve estimates are less precise than those of proved reserves. Generally, in the Company s business combinations, the determination of the fair values of oil and gas properties requires more judgment than the estimates of fair values for other acquired assets and liabilities.

Future Development and Abandonment Costs

Future development costs include costs incurred to obtain access to proved reserves, including drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our offshore production platforms, FPSOs, FSOs, gathering systems, wells and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. The accounting for future development and abandonment costs will change on January 1, 2003, with the adoption of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations .

Income Taxes

For financial reporting purposes, the Company generally provides taxes at the rate applicable for the appropriate tax jurisdiction. Where the Company s present intention is to reinvest the unremitted earnings in its foreign operations, the Company does not provide for U.S. income taxes on unremitted earnings of foreign subsidiaries. Management periodically assesses the need to utilize these unremitted earnings to finance the U.S. operations of the Company. This assessment is based on cash flow projections that are the result of estimates of future production, commodity pricing and expenditures by tax jurisdiction for the Company s operations. Such estimates are inherently imprecise since many assumptions utilized in the cash flow projections are subject to revision in the future.

Management also periodically assesses, by tax jurisdiction, the probability of recovery of recorded deferred tax assets based on its assessment of future earnings outlooks. Such estimates are inherently imprecise since many assumptions utilized in the assessments are subject to revision in the future.

Results of Operations

Net income

The Company reported 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), compared to net income for the third quarter of 2001 of $15,603,000 or $0.29 per share ($17,187,000 or $0.28 per share on a diluted basis). For the first nine months of 2002, the Company reported net income of $69,280,000 or $1.22 per share ($75,023,000 or $1.17 per share on a diluted basis) compared to net income for the first nine months of 2001 of $86,528,000 or $1.72 per share ($94,364,000 or $1.57 per share on a diluted basis). The increase in net income during the third quarter of 2002 compared to the third quarter of 2001 was primarily related to increased production from the Company s Gulf of Mexico and Thailand properties. The decrease in net income during the first nine months of 2002 compared to the first nine months of 2001 was primarily related to decreases in the average prices that the Company received for its natural gas, crude oil and condensate production volumes and increased depreciation, depletion and amortization (DD&A) expense and lease operating expenses related to higher production on the Company s Gulf of Mexico and Thailand properties. The decreases in prices and the increases in certain expenses were only partially offset by increased revenue related to higher production from the Company s Gulf of Mexico and Thailand properties, as well as production from properties acquired in the North Central acquisition that closed on March 14, 2001. The net income reported in the third quarter and first nine months of 2002, compared to the third quarter and first nine months of 2001, was also positively impacted by a $3,900,000 gain on the sale of the Sea Robin gas plant, which was partially offset by losses from the sale of several marginal offshore properties in the Gulf of Mexico as part of the Company s ongoing asset rationalization process during the first nine months of 2002. Net income reported in the third quarter and first nine months of 2001 was also positively impacted by a gain on the sale of certain non-strategic properties.

Earnings per common share are based on the weighted average number of common shares outstanding for the respective periods. The increase in the weighted average number of common shares outstanding for the third quarter and first nine months of 2002, compared to the third quarter and first nine months of 2001, resulted primarily from the issuance of common stock in connection with the conversion of the Company s Trust Preferred Securities that were called for redemption on June 3, 2002 and, to a lesser extent, the exercise of stock options pursuant to the Company s incentive plans. Earnings per share computations on a diluted basis for all periods reflect additional shares of common stock issuable upon the assumed exercise of options to purchase common shares under the Company s incentive plans, less treasury shares that are assumed to have been purchased by the Company from the option proceeds. Earnings per share computations on a diluted basis for the first nine months of 2002, and for the third quarter and first nine months of 2001, reflect the weighted average of additional shares of common stock issuable upon the assumed conversion of the Trust Preferred Securities (prior to their conversion). Earnings per share computations for all periods presented, with the exception of the third quarter of 2001, also reflect the weighted average of additional shares of common stock issuable upon the assumed conversion of the Company s 5½% Convertible Subordinated Notes due 2006 (the 2006 Notes).

Total Revenues

The Company s total revenues for the third quarter of 2002 were $207,808,000, an increase of approximately 45% from total revenues of $143,535,000 for the third quarter of 2001. The Company s total revenues for the first nine months of 2002 were $535,103,000, an increase of approximately 11% compared to total revenues of $482,791,000 for the first nine months of 2001. The increase in the Company s total revenues for the third quarter and the first nine months of 2002, compared to the third quarter and first nine months of 2001, resulted primarily from an increase in oil and gas revenues as described below, that was partially offset by a decrease in pipeline sales attributable to the Company s sale of the Saginaw pipeline in the fourth quarter of 2001.

Oil and Gas Revenues

The Company s oil and gas revenues for the third quarter of 2002 were $203,919,000, an increase of approximately 46% from oil and gas revenues of $139,677,000 for the third quarter of 2001. The Company s oil and gas revenues for the first nine months of 2002 were $531,457,000, an increase of approximately 14% from oil and gas revenues of $468,002,000 for the first nine months of 2001. The following table reflects an analysis of variances in the Company s oil and gas revenues (expressed in thousands) between 2002 and 2001:

Increase (decrease) in oil and gas revenues resulting from variances in:

	3rd Quarter 2002 Compared to 3rd Quarter 2001	9 Months 2002 Compared to 9 Months 2001
Natural gas		
Price	$ (2,472)	$ (79,170)
Production	9,365	33,407
	6,893	(45,763)
Crude oil and condensate		
Price	4,927	(16,470)
Production	48,571	116,294
	53,498	99,824
Natural gas liquids	3,851	9,394
Increase (decrease) in oil and gas revenues	$ 64,242	$ 63,455

The increase in the Company s oil and gas revenues for the third quarter of 2002, compared to the third quarter of 2001, is primarily related to increases in the Company s oil and condensate, natural gas and NGL production volumes and, to a lesser extent, an increase in the average price that the Company received for its crude oil and condensate volumes. The increase in the Company s oil and gas revenues for the first nine months of 2002, compared to the first nine months of 2001, is primarily related to increases in the Company s oil and condensate, natural gas and NGL production volumes, which were only partially offset by lower prices received for the Company s natural gas production and, to a lesser extent, lower prices received for the Company s crude oil, condensate and NGL production.

Comparison of Increases (Decreases) in:

	3rd Quarter			1st Nine Months		
	2002	**2001**	**% Change**	**2002**	**2001**	**% Change**
Natural Gas						
Average prices						
North America (a)	**$ 2.92**	$ 2.99	**(2)%**	**$ 2.98**	$ 4.61	**(35)%**
Kingdom of Thailand (b)	**$ 2.15**	$ 2.28	**(6)%**	**$ 2.19**	$ 2.31	**(5)%**
Company-wide average price	**$ 2.70**	$ 2.81	**(4)%**	**$ 2.76**	$ 4.00	**(31)%**
Average daily production volumes (MMcf per day)						
North America (a)	**204.3**	183.3	**11%**	**200.5**	171.4	**17%**
Kingdom of Thailand	**79.9**	63.2	**26%**	**77.5**	62.3	**24%**
Company-wide average daily production	**284.2**	246.5	**15%**	**278.0**	233.7	**19%**
Crude Oil and Condensate						
Average prices (c)						
North America	**$ 26.95**	$ 25.51	**6%**	**$ 24.05**	$ 26.40	**(9)%**
Kingdom of Thailand	**$ 26.76**	$ 24.85	**8%**	**$ 23.87**	$ 25.76	**(7)%**
Company-wide average price	**$ 26.88**	$ 25.17	**7%**	**$ 23.99**	$ 26.09	**(8)%**
Average daily production volumes (Bbls per day)						
North America (c)	**32,419**	15,009	**116%**	**30,060**	14,815	**103%**
Kingdom of Thailand (d)	**17,459**	15,283	**14%**	**16,568**	14,220	**17%**
Company-wide average daily production	**49,878**	30,292	**65%**	**46,628**	29,035	**61%**
Total Liquid Hydrocarbons						
Company-wide average daily production (Bbls per day)(d)	**55,242**	32,824	**68%**	**51,302**	30,812	**67%**

(a) North American average prices and production reflect production from the United States and Canada and the impact of the Company s price hedging activity**.** Price hedging activity added $0.03 and $0.15 to the average price of the Company s North American natural gas production during the third quarter and first nine months of 2002, respectively, and reduced the average price $0.30 and $0.05, respectively, during the third quarter and first nine months of 2001.The Company sold its operations in Canada effective August 31, 2001, as part of an asset rationalization process. Consequently, results for the 2002 comparative periods do not reflect any production from Canada. MMcf is an abbreviation for million cubic feet.

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

(c) North American average prices and production reflect production from the United States and Canada. The Company sold its operations in Canada effective August 31, 2001, as part of an asset rationalization process. Consequently, results for the 2002 comparative periods do not reflect any production from Canada. Average prices are computed on production that is actually sold during the period. For North American average prices, this equates to actual production. However, in the Gulf of Thailand, crude oil and condensate sold may be more or less than actual production. See footnote (d). Bbls is an abbreviation for barrels.

(d) 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 are a more meaningful measure of the Company s operating results and therefore reports production volumes as part of its operating results. 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. The Company produced 94,000 barrels less than it sold in the third quarter of 2001 and 110,000 barrels more than it sold in the first nine months of 2001, 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. The price that the Company receives from PTT under a memorandum of understanding that it executed in 2001 for certain volumes it produces in excess of the contractual amount under the gas sales agreement is generally equal to 88% of the then-current price under its gas sales agreement. The decrease in the average price that the Company received for its natural gas production in the Kingdom of Thailand for the third quarter and first nine months of 2002, compared to the third quarter and first nine months of 2001, reflects a downward adjustment in the average price received under the gas sales agreement and, to a lesser extent, a reduced average price received on the excess production sold at lower prices under the memorandum of understanding.

North American Production. The increase in the Company s domestic natural gas production during the third quarter of 2002, compared to the third quarter of 2001, was primarily attributable to the Company s successful development programs on its Gulf of Mexico properties, including its Mississippi Canyon Blocks 661/705 Field, and the ongoing development program on its Los Mogotes field in South Texas, partially offset by natural production declines at other properties and weather related shut downs in the Gulf of Mexico. The increase in the Company s domestic natural gas production during the first nine months of 2002, compared to the first nine months of 2001, was primarily related to production from properties acquired in the North Central acquisition and, to a lesser extent, successful development programs on the Company s Gulf of Mexico properties, including its Mississippi Canyon Blocks 661/705 Field, partially offset by natural production declines at other properties and weather related shut downs in the Gulf of Mexico.

Thailand Production. The increase in the Company s Thailand natural gas production during the third quarter and first nine months of 2002, compared to the third quarter and first nine months of 2001, was primarily related to increased production under the memorandum of understanding.

Crude Oil and Condensate

Thailand Prices. Since the inception of production from the Company s properties located in the Gulf of Thailand, crude oil and condensate have been stored on storage vessels (an FPSO in the Tantawan field and an FSO in the Benchamas field) until an economic quantity is accumulated for offloading and sale. 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. The Company is generally paid for its crude oil and condensate production from Thailand in U.S. dollars.

North American Production. The increase in the Company s North American crude oil and condensate production during the third quarter and first nine months of 2002, compared to the third quarter and first nine months of 2001, primarily related to commencement of production from the Company s Main Pass Blocks 61/62 Field, its Mississippi Canyon 661/705 Field and its Ewing Bank Block 871 Field, partially offset by natural production declines at certain other properties.

Thailand Production. The increase in the Company s crude oil and condensate production from the Gulf of Thailand during the third quarter and first nine months of 2002, compared to the third quarter and first nine months of 2001, primarily related to the continuing success of the Company s development program in the Benchamas Field and, to a lesser extent, increased crude oil and condensate production associated with the increased natural gas production permitted by the memorandum of understanding. The Company anticipates that production facilities upgrades at Benchamas Field, that had been scheduled for the third quarter of 2002 but were postponed and are currently scheduled for the first quarter of 2003, could require the Benchamas Field to be shut-in for 20-25 days, resulting in a reduction of the Company s net first quarter 2003 oil production by about 5,000 barrels per day.

In accordance with generally accepted accounting principles, the Company records its oil production in 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. The Company believes that actual production volumes are a more meaningful measure of the Company s operating results than sales volumes and therefore reports production volumes as part of its operating results. 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. It produced 94,000 barrels less than it sold in the third quarter of 2001 and 110,000 barrels more than it sold in the first nine months of 2001. As of September 30, 2002, the Company had approximately 325,000 net barrels stored on board the FPSO and FSO.

NGL Production. The Company s oil and gas revenues, and its total liquid hydrocarbon production, reflect the production and sale by the Company of NGL, which are liquid products extracted from natural gas production. The increase in NGL revenues for the third quarter and first nine months of 2002, compared with the third quarter and first nine months of 2001, primarily related to NGL removed from the Company s Mississippi Canyon Blocks 661/705 Field gas production. These increases were partially offset by a decline in the average prices that the Company received for its NGL production during the comparative periods.

Costs and Expenses

Comparison of Increases (Decreases) in:

	3rd Quarter			Nine Months		
	2002	2001	% Change	2002	2001	% Change
Lease Operating Expenses						
North America	**$ 26,091,000**	$ 21,163,000	**23%**	**$ 73,362,000**	$ 60,934,000	**20%**
Kingdom of Thailand	**$ 8,897,000**	$ 10,776,000	**(17)%**	**$ 27,494,000**	$ 26,528,000	**4%**
Total Lease Operating Expenses	**$ 34,988,000**	$ 31,939,000	**10%**	**$ 100,856,000**	$ 87,462,000	**15%**
Pipeline Operating and Natural Gas Purchases	**$ 2,133,000**	$ 1,838,000	**16%**	**$ 2,314,000**	$ 10,258,000	**(77)%**
General and Administrative Expenses	**$ 14,445,000**	$ 11,281,000	**28%**	**$ 36,815,000**	$ 29,139,000	**26%**
Exploration Expenses	**$ 2,508,000**	$ 5,013,000	**(50)%**	**$ 3,684,000**	$ 17,447,000	**(79)%**
Dry Hole and Impairment Expenses	**$ 8,179,000**	$ 3,053,000	**168%**	**$ 16,674,000**	$ 26,097,000	**(36)%**
Depreciation, Depletion and Amortization (DD&A) Expenses	**$ 73,960,000**	$ 55,754,000	**33%**	**$ 213,708,000**	$ 146,286,000	**46%**
DD&A rate	**$ 1.27**	$ 1.33	**(5)%**	**$ 1.32**	$ 1.27	**4%**
Mcfe sold (a)	**57,240,000**	41,363,000	**38%**	**159,539,000**	113,604,000	**40%**
Interest						
Charges	**$ (14,364,000)**	$ (15,119,000)	**(5)%**	**$ (43,452,000)**	$ (41,411,000)	**5%**
Interest Income	**$ 404,000**	$ 690,000	**(41)%**	**$ 1,316,000**	$ 2,686,000	**(51)%**
Capitalized Interest Expense	**$ 5,933,000**	$ 9,324,000	**(36)%**	**$ 19,445,000**	$ 24,153,000	**(19)%**
Minority Interest Dividends and Costs	**$**	$ (2,501,000)	**(100)%**	**$ (4,140,000)**	$ (7,499,000)	**(45)%**
Foreign Currency Transaction Gain (Loss)	**$ (458,000)**	$ 338,000	**(236)%**	**$ 873,000**	$ (668,000)	**(231)%**
Income Tax Expense	**$ (31,473,000)**	$ (11,786,000)	**167%**	**$ (65,814,000)**	$ (56,835,000)	**16%**

(a) Mcfe stands for thousands of cubic feet equivalent

Lease Operating Expenses.

The increase in North American lease operating expenses for the third quarter and first nine months of 2002, compared to the third quarter and first nine months of 2001, is related to higher production from the Company s Gulf of Mexico properties, and to a lesser extent, increased maintenance costs during this period, partially offset by decreased severance taxes. As a result of the increased production from its Gulf of Mexico properties, the Company has also incurred increased product transportation and processing expenses and increased rental expenses for compressors and other equipment during 2002. In addition to the above factors, the increased lease operating expenses associated with properties acquired in the acquisition of North Central (completed on March 14,2001) also impact the comparison of the first nine months of 2002 to the first nine months of 2001.

The decrease in lease operating expenses in the Kingdom of Thailand for third quarter of 2002, compared to the third quarter of 2001, primarily related to decreased rental expenses for compressors and other equipment and an increase in the amount of lifting costs carried as a product inventory asset. The increase in lease operating expenses in the Kingdom of Thailand for the first nine months of 2002, compared to the first nine months of 2001, primarily related to increased insurance costs and a decrease in the amount of lifting costs carried as a product inventory asset. In accordance with generally accepted accounting practices, 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 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 charter of the FPSO for the Tantawan field and the FSO for the Benchamas field. Collectively, these lease payments accounted for $3,665,000 and $10,876,000 (net to the Company s interest) of the Company s Thailand lease operating expenses for the third quarter and first nine months of 2001 and 2002, respectively.

Notwithstanding the overall increase in lease operating expenses, on a per unit of production basis, the Company s total lease operating expenses decreased from an average of $0.78 per Mcfe for the third quarter and $0.77 per Mcfe for the first nine months of 2001 to $0.62 per Mcfe for the third quarter and $0.63 per Mcfe for the first nine months of 2002.

Pipeline Operating and Natural Gas Purchases

Revenue from the sale of natural gas purchased for resale is reported under Pipeline sales. The cost of purchasing natural gas, in addition to the costs of operating the Company s pipeline carrying the natural gas, is recorded as an expense under Pipeline operating and natural gas purchases. During 2001, primarily all of the natural gas purchased and resold by the Company was transported on Pogo Onshore Pipeline Company s Saginaw pipeline, which was sold during the fourth quarter of 2001 as part of the Company s ongoing asset rationalization process. During 2002, substantially all of the gas purchased by the Company is the result of purchases of natural gas volumes required to replace the reduction in Btu content of the gas stream after the extraction of NGLs. These purchases were made to bring the gas stream to pipeline quality standards. Prior to 2002, the Company had been using its own natural gas production to replenish this extracted gas. Consequently, there is no meaningful comparison between the quarterly and nine month periods for 2001 and 2002.

General and Administrative Expenses

The increase in general and administrative expenses for the third quarter of 2002, compared with the third quarter of 2001, is primarily related to normal increases in compensation and concomitant benefit expense, in addition to increases in map purchases and insurance costs. The increase in general and administrative expenses for the first nine months of 2002, compared with the first nine months of 2001, related to increased expenses associated with the Company s acquisition of North Central and its employees, as well as other increases in the size of the Company s work force, normal increases in compensation and concomitant benefit expense, and to a lesser extent, increases in map purchases, office rent 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 decreased from an average of $0.28 per Mcfe for the third quarter and $0.26 per Mcfe for the first nine months of 2001 to $0.26 per Mcfe for the third quarter and $0.23 per Mcfe for the first nine months 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 decrease in exploration expense for the third quarter and first nine months of 2002, compared to the third quarter and first nine months of 2001, resulted primarily from a decrease in 3-D seismic acquisition activities during the 2002 periods. Exploration expenses for the third quarter of 2001 included the cost of acquisition of 3-D data in the Company s Offshore and Western divisions and payment to transfer North Central seismic licenses, for which no comparable expenses were experienced during the same period in 2002. Exploration expenses for the first nine months of 2001 included the cost of conducting two major 3-D projects in Hungary, seismic operations in Canada and the Gulf of Mexico, and a payment to transfer seismic licenses used by North Central, for which no comparable expenses were experienced during the same period in 2002.

Dry Hole and Impairment

The increase in the Company s dry hole and impairment expense for the third quarter of 2002, compared to the third quarter of 2001, resulted from an increase in the cost of the Company s unsuccessful exploratory wells, partially offset by a reduction in the number and value of properties that were impaired during the 2002 period, as compared to the 2001 period. The decrease in the Company s dry hole and impairment expense for the first nine months of 2002, compared to the first nine months of 2001, resulted from a decrease in the cost of the Company s unsuccessful exploratory wells as well as a reduction in the number and value of properties that were impaired during the 2002 period, as compared to the 2001 period.

Depreciation, Depletion and Amortization Expenses

The increase in the Company s DD&A expense for the third quarter and first nine months of 2002, compared to the third quarter and first nine months of 2001, resulted primarily from an increase in the Company s natural gas and liquid hydrocarbon production.

The decrease in the composite DD&A rate for all of the Company s producing fields for the third quarter of 2002, compared to the third quarter of 2001, was primarily attributable to increased production from fields with a DD&A rate lower than the Company s recent historic average (principally the new Main Pass Blocks 61/62 Field and the Benchamas Field). The increase in the composite DD&A rate for all of the Company s producing fields for the first nine months of 2002, compared to the first nine months of 2001, was primarily attributable to production from fields acquired in the North Central acquisition which, because they were valued at fair market value in connection with the acquisition, contribute a DD&A rate higher than the Company s recent historic average. Such rate increases were partially offset by increased production from certain of the Company s fields having DD&A rates lower than the Company s recent historical composite rate.

Interest

Interest Charges. The decrease in the Company s interest charges for the third quarter of 2002, compared to the third quarter of 2001, resulted primarily from a decline in the average interest rate on the Company s outstanding debt, partially offset by an increase in the average debt outstanding during the periods**.** The increase in the Company s interest charges for the first nine months of 2002, compared to the first nine months of 2001, was primarily related to additional debt incurred to finance the North Central acquisition, which was partially offset by a decline in the average interest rate on the outstanding debt and a reduction in amortization of debt issuance costs incurred in the first nine months of 2001. These charges related to the termination of the Company s previous credit facility in connection with the North Central acquisition.

Interest Income. The decrease in the Company s interest income for the third quarter and first nine months of 2002, compared to the third quarter and first nine months of 2001, resulted primarily from a decline in the average interest rate that the Company received on its cash and cash equivalents temporarily invested. The cash and cash equivalents on the Company s balance sheet at September 30, 2002, are primarily denominated in U.S. dollars and held by the Company s international subsidiaries for future investment overseas.

Capitalized Interest. The decrease in capitalized interest for the third quarter of 2002, compared to the third quarter of 2001, resulted primarily from a decrease in the average amount of capital expenditures subject to interest capitalization (approximately $380,000,000 in the third quarter of 2002, compared to approximately $407,000,000 in the third quarter of 2001) and, to a lesser extent, by a decrease in the interest rate used to determine the amount of capitalized interest. The decrease in capitalized interest for the first nine months of 2002, compared to the first nine months of 2001, resulted primarily from a decrease in the interest rate used to determine the amount of capitalized interest, partially offset by an increase in the amount of capital expenditures subject to interest capitalization (approximately $379,000,000 in the first nine months of 2002, compared to approximately $346,000,000 in the first nine months of 2001). A substantial percentage of the Company s capitalized interest relates to unevaluated properties acquired in the North Central acquisition and capital expenditures for the development of the Benchamas field in the Gulf of Thailand and several other development projects in the Gulf of Mexico. The Company currently expects the amount of capital expenditures subject to interest capitalization to decrease during the remainder of 2002 due to the recent completion and installation of platforms and facilities construction in the Gulf of Thailand and the Gulf of Mexico.

Minority Interest Dividends and Costs Associated
with 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 for the third quarter and first nine months of 2001 and the first nine months of 2002, respectively, under Minority Interest Dividends and Costs Associated with Preferred Securities of a Subsidiary Trust 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.

Foreign Currency Transaction Gain (Loss)

The foreign currency transaction gains reported for the third quarter of 2001 and first nine months of 2002, and the losses reported for the third quarter of 2002 and the first nine months of 2001, resulted primarily from the fluctuation against the U.S. dollar of cash and other monetary assets and liabilities denominated in Thai Baht that were included in the Company s Thai subsidiaries financial statements during the respective periods. The Company cannot predict with any degree of certainty the Thai Baht to U.S. dollar exchange rate in future periods. As of October 28, 2002, the Company was not a party to any financial instrument intended to constitute a foreign currency hedging arrangement.

Income Tax Expense

The increase in the Company s tax expense for the third quarter and first nine months of 2002, compared to the third quarter and first nine months of 2001, resulted from an increase in the Company s effective tax rate during the comparative periods in addition to increased pre-tax income during the third quarter comparative periods. The higher effective tax rate is the result of higher pre-tax income derived from the Company s Thailand operations during the comparative periods, which is taxed at a rate higher than the U.S. statutory rate, relative to its pre-tax income from North American operations. Management currently expects that foreign income taxes will constitute a substantial portion of its overall tax burden for the foreseeable future.

Liquidity and Capital Resources

Cash Flows

The Company s Condensed Consolidated Statement of Cash Flows for the first nine months of 2002 reflects net cash provided by operating activities of $348,299,000. In addition to net cash provided by operating activities, the Company received $17,399,000 from the exercise of stock options and $4,255,000 from the sale of non-strategic properties. During the first nine months of 2002, the Company invested $276,392,000 in capital projects, repaid a net $55,005,000 under its senior debt arrangements, paid a total of $4,997,000 in cash distributions to holders of its Trust Preferred Securities (including $147,000 in connection with the redemption of the Trust Preferred Securities on June 3, 2002), paid $5,064,000 ($0.09 per share) in cash dividends to holders of the Company s common stock and paid $182,000 in debt issue costs. As of October 28, 2002, the Company s cash and cash equivalents were $126,634,000 and its long-term debt stood at $739,945,000. In addition, the Company had $225,000,000 of availability under its revolving credit facility.

Future Capital Requirements

The Company s capital and exploration budget for 2002, 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, is $390,000,000. The Company currently anticipates that its available cash and cash equivalents, cash provided by operating activities and funds available under its revolving credit agreement and banker s acceptance facility will be sufficient to fund the Company s ongoing operating, interest and general and administrative expenses, any currently anticipated costs associated with the Company s projects during 2002, and future dividend payments at current levels (including a dividend payment of $0.03 per share on its common stock to be paid on November 15, 2002 to shareholders of record on November 1, 2002). The declaration 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 under covenants contained in its debt instruments, the general economic and regulatory climate and other factors deemed relevant by the Company s Board of Directors.

Material Contractual Cash Obligations

The Company s material contractual cash obligations include long-term debt, operating leases, and other contracts. Material contractual cash obligations for which the ultimate settlement amounts are not fixed and determinable include derivative contracts that are sensitive to future changes in commodity prices and other factors. See Item 3. Quantitative and Qualitative Disclosure about Market Risk. A summary of the Company s known contractual obligations as of September 30, 2002 is set forth on the following table:

	Payments Due By Year (in millions)						
	Rest of 2002	**2003**	**2004**	**2005**	**2006**	**After 2006**	**Total**
Long Term Debt	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 290.0	$ 450.0	$ 740.0
Operating Leases (a)	$ 5.4	$ 21.2	$ 21.2	$ 21.1	$ 21.0	$ 62.1	$ 152.0
Drilling obligations (b)	$ 5.4	$ 5.4	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 10.8
Firm transportation agreements (c)	$ 0.3	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 5.1	$ 10.2
Total	$ 11.1	$ 27.8	$ 22.4	$ 22.3	$ 312.2	$ 517.2	$ 913.0

(a) Operating leases principally include the lease of the FPSO and FSO in Thailand, the Company s office lease commitments and various other equipment rentals, including gas compressors. Where rented equipment such as compressors is considered essential to the operation of the lease, the Company has assumed that such equipment will be leased for the estimated productive life of the reserves, even if the contract terminates prior to such date.

(b) This represents the Company s share of the contractual commitments for one rig drilling in the Madden Field in Wyoming and two rigs in the Gulf of Thailand. No other drilling rigs working for the Company are currently under contracts that have a term greater than six months or cannot be terminated at the end of the well that is currently being drilled. Due to their short-term nature and our inability to quantify the remaining liabilities on rigs drilling on a well-by-well basis, such obligations have not been included in this table.

(c) Firm transportation agreements represent ship-or-pay arrangements whereby the Company has committed to ship certain volumes of gas for a fixed transportation fee (principally from the Madden Field in Wyoming). The Company entered into these arrangements to ensure its access to gas markets and currently expects to produce sufficient volumes to satisfy substantially all of its firm transportation obligations.

Commitments under Joint Operating Agreements. The oil and gas industry operates in many instances through joint ventures under joint operating agreements and the Company s operations are no exception. Typically, the operator under a joint operating agreement enters into contracts, such as drilling contracts, for the benefit of all joint venture partners. Through the joint operating agreement, the non-operators reimburse, and in some cases advance, the funds necessary to meet the contractual obligations entered into by the operator. These obligations are typically shared on a working interest basis. The joint operating agreement provides remedies to the operator in the event that the non-operator does not satisfy its share of the contractual obligations. Occasionally, the operator is permitted by the joint operating agreement to enter into lease obligations and other contractual commitments that are then passed on to the non-operating joint interest owners as lease operating expenses, frequently without any identification as to the long-term nature of any commitments underlying such expenses. The contractual obligations set forth above represent the Company s working interest share of the contractual commitments that it has entered into as operator and, to the extent that it is aware, the contractual commitments entered into by the operator of projects that the Company does not operate.

Surety Bonds. In the ordinary course of the Company s business and operations, it is required to post surety bonds from time to time with third parties, including governmental agencies, primarily to cover self insurance, site restoration, equipment dismantlement, plugging and abandonment obligations. As of September 30, 2002, the Company had obtained surety bonds from a number of insurance and bonding institutions covering certain operations in the United States in the aggregate amount of approximately $7,000,000 that are not included in the prior table. In connection with their administration of offshore leases in the Gulf of Mexico, the MMS annually evaluates each lessee s plugging and abandonment liabilities. The MMS reviews this information and applies certain financial tests including, but not limited to, current asset and net worth tests. The MMS determines whether each lessee is financially capable of paying the estimated costs of such plugging and abandonment liabilities. The Company must annually provide the MMS with financial information. If the Company does not satisfy the MMS requirements, it could be required to post supplemental bonds. In the past, the Company has not been required to post supplemental bonds; however, there can be no assurance that the Company will satisfy the financial tests and remain on the list of MMS lessees exempt from the supplemental bonding requirements. The Company cannot predict or quantify the amount of any such supplemental bonds or the annual premiums related thereto and therefore has not included them in the prior table, but the amount could be substantial.

Guarantee and Letters of Credit. The Company has also issued performance guarantees related to the operations of its subsidiaries in Thailand, Hungary, the U.K and Denmark. If its subsidiaries do not fulfill their contractual obligations or legal obligations under the relevant local laws, the Company could be obligated to make payments to satisfy the subsidiaries obligations. Most of these obligations relate to plugging, abandoment, site restoration and compliance with environmental laws. The Company also has guaranteed performance of its subsidiaries obligations under the FSO and FPSO leases. To the extent quantifiable, such subsidiaries contractual commitments have been included in the prior table. However, the Company s guarantee of these obligations has not been so included. Currently, there are no letters of credit that have been issued on the Company s behalf.

Recent Accounting Pronouncements

The Financial Accounting Standards Board has issued a new pronouncement, Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations (SFAS 143). SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. The Company will adopt this standard as required on January 1, 2003. Adoption of the standard will result in recording a cumulative effect of a change in accounting principle to earnings in the period of adoption. The Company has not yet fully quantified the financial statement impact from adoption of this new standard.

The Financial Accounting Standards Board has issued a new pronouncement, Statement of Financial Accounting Standards No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections (SFAS 145). SFAS 145 provides guidance for income statement classification of gains and losses on extinguishment of debt and accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. The Company adopted this standard as required on May 15, 2002. Implementation of the new standard had no impact upon adoption and is not currently expected to have a material financial statement impact on the Company**.**

The Financial Accounting Standards Board has issued a new pronouncement, Statement of Financial Accounting Standards No. 146, Accounting for Exit of Disposal Activities (SFAS 146). SFAS 146 addresses significant issues regarding the recognition, measurement and reporting of costs that are associated with exit and disposal activities, including restructuring activities that are currently accounted for pursuant to the guidance set forth in EITF Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity . The Company will adopt this standard as required on January 1, 2003. Adoption of the standard is not expected to have a material financial statement impact on the Company.

ITEM 3. *Quantitative and Qualitative Disclosure about Market Risk.*

The Company is exposed to market risk, including adverse changes in commodity prices, interest rates and foreign currency exchange rates. The information contained in the Company s Annual Report on Form 10-K for the year ended December 31, 2001 should be read in conjunction with the following.

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 28, 2002, the Company had 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, 2002:

	2002	2003	2004	2005	2006	Thereafter	Total	Fair Value
Long-Term Debt:								
Variable Rate	$ 0	$ 0	$ 0	$ 0	$ 175,000	$ 0	$ 175,000	$ 175,000
Average Interest Rate					3.06%		3.06%	
Fixed Rate	$ 0	$ 0	$ 0	$ 0	$ 115,000	$ 450,000	$ 565,000	$ 590,537
Average Interest Rate					5.50%	9.07%	8.34%	

Foreign Currency Exchange Rate Risk

The Company conducts business in Thai Baht and Hungarian Forint and is therefore subject to foreign currency exchange rate risk on cash flows related to revenue, expenses, financing and investing transactions. As of October 28, 2002, the Company is not a party to any foreign currency exchange rate agreement.

Current Hedging Activity

From time to time, the Company has used and expects to continue to use hedging transactions with respect to a portion of its oil and gas production to achieve a more predictable cash flow, as well as to reduce its exposure to price fluctuations on anticipated future natural gas and crude oil production.

As of September 30, 2002, the Company held various derivative instruments. In addition to the remaining term of the natural gas floor contracts entered into late in 2000, the Company at the end of the third quarter and early in the fourth quarter of 2002, entered into natural gas and crude oil option agreements referred to as collars . Collars are designed to establish floor and ceiling prices. 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 credit worthiness 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 floor contract, 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. The Company is not required to make any payment in connection with the settlement of a floor contract. 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 September 30, 2002, are as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price		Fair Market Value
		Floor	Ceiling	
Natural Gas Contracts (MMBtu) (a)				
Floor Contract:				
October 2002 December 2002	6,440	$ 4.00		$ 1,618,000
Collar Contracts:				
January 2003 December 2003	1,825	$ 3.85	$ 5.00	$ 301,000
Crude Oil Contracts (Barrels)				
Collar Contracts:				
October 2002 December 2003	2,742,000	$ 25.00	$ 30.00	$ 2,331,000

(a) MMBtu means million British Thermal Units.

In October 2002, the Company entered into additional natural gas and crude oil option agreements (collars) to establish floor and ceiling prices on anticipated future natural gas and crude oil production. The Company has designated these contracts as cash flow hedges. Further details related to these hedging activities are as follows:

		NYMEX Contract Price	
Contract Period and Type of Contract	**Volume**	**Floor**	**Ceiling**
Natural Gas Contracts (MMBtu)			
Collar Contracts:			
January 2003 December 2003	12,775	$ 3.85	$ 5.00
Crude Oil Contracts (Barrels)			
Collar Contracts:			
October 2002 December 2003	1,828,000	$ 25.00	$ 30.00

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.

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 October 31, 2002, 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 October 31, 2002, by James P. Ulm II, Senior Vice President and Chief Financial Officer of Pogo Producing Company.

(B) Reports on Form 8-K

None

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: October 31, 2002

/s/ Paul G. Van Wagenen

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

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: October 31, 2002

/s/ James P. Ulm, II

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

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 31, 2002