POGO PRODUCING CO
Form 10-Q
July 25, 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 June 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 **(State or Other Jurisdiction of Incorporation or Organization)**	**74-1659398** **(I.R.S. Employee Identification No.)**
5 Greenway Plaza, Suite 2700 **Houston, Texas** **(Address of principal executive offices)**	**77046-0504** **(Zip Code)**

(713) 297-5000
(Registrant s Telephone Number, Including Area Code)

Not Applicable
(Former Name, Former Address and Former Fiscal Year, if Changed Since Last Report)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirement for the past 90 days: Yes x No ¨

Registrant s number of common shares outstanding as of July 22, 2002: 60,738,662

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

POGO PRODUCING COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2002	**2001**	**2002**	**2001**
	(Expressed in thousands, except per share amounts)			
Revenues:				
Oil and gas	$ 185,241	$ 164,412	$ 327,538	$ 328,325
Pipeline sales	1	4,473	79	8,699
Gains (losses) on sales and other	(857)	509	(322)	2,232
Total	184,385	169,394	327,295	339,256
Operating Costs and Expenses:				
Lease operating	34,585	29,696	65,868	55,523
Pipeline operating and natural gas purchases		4,400	181	8,420
General and administrative	10,828	9,650	22,370	17,858
Exploration	1,352	5,486	1,176	12,434
Dry hole and impairment	3,500	12,277	8,495	23,044
Depreciation, depletion and amortization	73,942	53,464	139,748	90,532
Total	124,207	114,973	237,838	207,811
Operating Income	60,178	54,421	89,457	131,445
Interest:				
Charges	(14,500)	(14,988)	(29,088)	(26,292)
Income	534	694	912	1,996
Capitalized	6,859	10,303	13,512	14,829
Minority Interest Dividends and costs associated with preferred securities of a subsidiary trust	(1,638)	(2,501)	(4,140)	(4,998)
Foreign Currency Transaction Gain (Loss)	659	(421)	1,331	(1,006)
Income Before Taxes	52,092	47,508	71,984	115,974
Income Tax Expense	(23,474)	(16,529)	(34,341)	(45,049)
Net Income	$ 28,618	$ 30,979	$ 37,643	$ 70,925
Earnings Per Common Share				
Basic	$ 0.51	$ 0.58	$ 0.68	$ 1.46
Diluted	$ 0.48	$ 0.53	$ 0.66	$ 1.31
Dividends Per Common Share	$ 0.03	$ 0.03	$ 0.06	$ 0.06

Weighted Average Number of Common Shares and Potential Common Shares Outstanding:

Basic	56,192	53,575	54,972	48,425
Diluted	64,340	63,494	61,210	58,373

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	June 30, 2002	December 31, 2001
	Expressed in thousands, except share amounts)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 110,500	$ 94,294
Accounts receivable	76,985	52,440
Other receivables	26,146	32,159
Federal income tax receivable		27,441
Deferred income tax	26,111	25,712
Inventories Product	4,684	3,129
Inventories Tubulars	9,471	8,430
Price hedge contracts	8,665	34,275
Other	9,760	1,970
Total current assets	272,322	279,850
Property and Equipment:		
Oil and gas, on the basis of successful efforts accounting		
Proved properties	3,100,241	2,956,673
Unevaluated properties	249,995	257,158
Pipelines, at cost	775	775
Other, at cost	24,039	21,638
	3,375,050	3,236,244
Accumulated depreciation, depletion and amortization		
Oil and gas	(1,246,423)	(1,133,560)
Pipelines	(733)	(739)
Other	(12,897)	(11,217)
	(1,260,053)	(1,145,516)
Property and equipment, net	2,114,997	2,090,728
Other Assets:		
Deferred income tax	8,465	13,359
Debt issue expenses	14,560	15,565
Foreign value added taxes receivable	10,698	6,200
Other	19,729	20,706
	53,452	55,830
	$ 2,440,771	$ 2,426,408

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	June 30, 2002	December 31, 2001
	(Expressed in thousands, except share amounts)	
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities:		
Accounts payable operating activities	$ 41,445	$ 34,962
Accounts payable investing activities	74,069	94,523
Accrued interest payable	11,259	11,450
Foreign income taxes payable	17,987	7,966
Accrued dividends associated with preferred securities of a subsidiary trust		813
Accrued payroll and related benefits	2,933	2,670
Deferred income tax	5,324	3,875
Other	1,613	1,892
Total current liabilities	154,630	158,151
Long-Term Debt	769,987	794,990
Deferred Income Tax	492,204	488,639
Deferred Credits	13,874	14,657
Total liabilities	1,430,695	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, 60,754,237 and 53,690,827 shares issued, respectively	60,754	53,691
Additional capital	814,604	659,227
Retained earnings	136,422	102,019
Accumulated other comprehensive income (loss)	(1,380)	10,272
Treasury stock (15,575 shares), at cost	(324)	(324)
Total shareholders equity	1,010,076	824,885
	$ 2,440,771	$ 2,426,408

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Six Months Ended June 30, 2002	Six Months Ended June 30, 2001
	(Expressed in thousands)	
Cash Flows from Operating Activities:		
Cash received from customers	$ 301,784	$ 365,015
Operating, exploration, and general and administrative expenses paid	(96,328)	(91,077)
Interest paid	(28,156)	(19,255)
Federal income taxes paid	(4,059)	(14,807)
Federal income taxes received	25,884	
Value added taxes paid	(4,498)	(2,129)
Price hedge contracts	15,683	
Other	527	2,051
Net cash provided by operating activities	210,837	239,798
Cash Flows from Investing Activities:		
Capital expenditures	(175,673)	(179,114)
Purchase of proved reserves		(2,714)
Proceeds from the sale of properties	5	4,348
Acquisition of NORIC, net of $21,235 cash acquired		(323,476)
Net cash used in investing activities	(175,668)	(500,956)
Cash Flows from Financing Activities:		
Proceeds from the issuance of new debt		200,000
Borrowings under senior debt agreements	364,997	833,997
Payments under senior debt agreements	(390,000)	(684,000)
Payments of cash dividends on common stock	(3,240)	(2,830)
Payments of preferred dividends of a subsidiary trust	(4,850)	(4,875)
Payment of financing issue costs	(130)	(8,625)
Payment of North Central senior debt acquired		(78,600)
Proceeds from exercise of stock options and other	14,174	5,472
Net cash (used in) provided by financing activities	(19,049)	260,539
Effect of exchange rate changes on cash	86	(948)
Net increase (decrease) in cash and cash equivalents	16,206	(1,567)
Cash and cash equivalents at the beginning of the year	94,294	81,510
Cash and cash equivalents at the end of the period	$ 110,500	$ 79,943
Reconciliation of net income to net cash provided by operating activities:		
Net income	$ 37,643	$ 70,925
Adjustments to reconcile net income to net cash provided by operating activities		
Minority interest	4,140	4,998
Foreign currency transaction (gains) losses	(1,331)	1,006
(Gains) losses from the sales of properties	303	(2,672)
Depreciation, depletion and amortization	139,748	90,532

Dry hole and impairment	8,495	23,044
Interest capitalized	(13,512)	(14,829)
Price hedge contracts	7,685	2,469
Deferred federal income taxes	15,611	21,784
Change in operating assets and liabilities	12,055	42,541
Net cash provided by operating activities	$ 210,837	$ 239,798

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY (UNAUDITED)

	For the Six Months Ended June 30,					
	2002			2001		
	Shareholders Equity		Compre-hensive Income	Shareholders Equity		Compre-hensive Income
	Shares	Amount		Shares	Amount	
	(Expressed in thousands, except share amounts)					
Common Stock:						
$1.00 par-200,000,000 shares authorized						
Balance at beginning of year	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	753,438	753		319,129	319	
Shares issued for acquisition of NORIC				12,615,816	12,615	
Issued at end of period	60,754,237	60,754		53,594,536	53,594	
Additional Capital:						
Balance at beginning of year		659,227			298,885	
Shares issued for Trust Preferred Securities conversion		138,720				
Stock options exercised		16,657			6,617	
Shares issued for acquisition of NORIC					351,729	
Balance at end of period		814,604			657,231	
Retained Earnings:						
Balance at beginning of year		102,019			20,112	
Net income		37,643	$ 37,643		70,925	
Dividends ($0.06 per common share)		(3,240)			(2,830)	$ 70,925
Balance at end of period		136,422			88,207	
Accumulated Other Comprehensive Income (Loss):						
Balance at beginning of year		10,272			(1,062)	
Exchange gains on Canadian currency					389	389
Unrealized gain (loss) on price hedge contracts		(6,453)	(6,453)		14,504	14,504
Cumulative effect of change in accounting principle					(2,438)	(2,438)
Reclassification adjustment for losses included in net income		(5,199)	(5,199)		(1,521)	(1,521)
Balance at end of period		(1,380)			9,872	
Comprehensive Income			$ 25,991			$ 81,859
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	60,738,662		53,578,961	
Total Shareholders Equity		$ 1,010,076		$ 808,580

See accompanying notes to consolidated financial statements.

POGO PRODUCING COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

(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 (Loss), which was $25,991,000 and $81,859,000, respectively, for the six months ended June 30, 2002 and 2001 ($28,356,000 and $44,562,000, respectively, for the three months ended June 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

The Company does not provide for U.S. income taxes on unremitted earnings of foreign subsidiaries where the Company s present intention is to reinvest the unremitted earnings in its foreign operations. Unremitted earnings of foreign subsidiaries for which U.S. income taxes have not been provided are approximately $69,879,000 at June 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. As of June 4, 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 six months ended June 30, 2002 of $6,453,000, net of deferred taxes of $3,475,000, have been reflected as a component of other comprehensive income. Based on the fair market value of the hedge contracts as of June 30, 2002, the Company would reclassify additional pre-tax losses of approximately $2,123,000 (approximately $1,380,000 net of taxes) from accumulated other comprehensive income, to net income during the remainder of 2002.

PRGO PRODUCING COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

As of June 30, 2002, the Company held options to sell 70 million cubic feet of natural gas production per day for the period from July 1, 2002 through December 31, 2002, at a sales price of $4.00 per MMBtu. The Company has designated these contracts as cash flow hedges designed to give the Company the right, but not the obligation, to sell natural gas. These contracts are designed to guarantee the Company a minimum floor price for the contracted volumes of production without limiting the Company s participation in price increases during the covered period. Further details related to the Company s hedging activities are as follows:

Contract Period	Volume in MMBtu(a)	NYMEX Contract Price per MMBtu(a)	Fair Market Value(b)
Floor Contract:			
July 2002 December 2002	12,880	$ 4.00	$ 8,665,000

(a) MMBtu means million British Thermal Units.
(b) Fair Market value is calculated using prices derived from NYMEX futures contract prices existing at June 30, 2002.

These hedging transactions are settled based upon the average of the reporting settlement prices on the NYMEX for the last three trading days, or occasionally the penultimate trading day, of a particular contract month. For any particular floor transaction, the counter-party 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 transaction.

As of June 30, 2002 the Company was not a party to any commodity price hedging contracts with respect to any of its current or future crude oil and condensate production.

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)			
Long-Lived Assets:				
As of June 30, 2002:				
United States	$ 1,770,394	$ 1,762,571	$ 42	$ 7,781
Kingdom of Thailand	344,229	340,972		3,257
Other	374	270		104
Total	$ 2,114,997	$ 2,103,813	$ 42	$ 11,142
As of December 31, 2001:				
United States	$ 1,748,046	$ 1,741,035	$ 36	$ 6,975
Kingdom of Thailand	342,411	338,965		3,446
Other	271	271		
Total	$ 2,090,728	$ 2,080,271	$ 36	$ 10,421
Capital Expenditures:				
(including interest capitalized)				
For the six months ended June 30, 2002				
United States	$ 127,373	$ 127,373	$	$
Kingdom of Thailand	42,746	42,746		
Other	2,288			2,288
Total	$ 172,407	$ 170,119	$	$ 2,288
For the year ended December 31, 2001				
United States	$ 1,458,549	$ 1,453,756	$	$ 4,793
Kingdom of Thailand	73,192	73,192		
Canada and other	3,071	3,071		
Total	$ 1,534,812	$ 1,530,019	$	$ 4,793
Revenues:				
For the three months ended June 30, 2002				
United States	$ 134,188	$ 135,063	$ 1	$ (876)
Kingdom of Thailand	50,194	50,178		16
Other	3			3
Total	$ 184,385	$ 185,241	$ 1	$ (857)
For the three months ended June 30, 2001				
United States	$ 129,618	$ 124,661	$ 4,473	$ 484
Kingdom of Thailand	38,077	38,067		10
Canada and other	1,699	1,684		15

Total	$ 169,394	$ 164,412	$ 4,473	$ 509
For the six months ended June 30, 2002				
United States	$ 235,884	$ 236,142	$ 79	$ (337)
Kingdom of Thailand	91,411	91,396		15
Other				
Total	$ 327,295	$ 327,538	$ 79	$ (322)
For the six months ended June 30, 2001				
United States	$ 249,090	$ 238,211	$ 8,699	$ 2,180
Kingdom of Thailand	86,071	86,012		59
Canada and other	4,095	4,102		(7)
Total	$ 339,256	$ 328,325	$ 8,699	$ 2,232

POGO PRODUCING COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

	Company	Oil and Gas	Pipelines	Other
		(Expressed in thousands)		
Depreciation, depletion and amortization expense:				
For the three months ended June 30, 2002				
United States	$ 54,023	$ 53,376	$ (15)	$ 662
Kingdom of Thailand	19,909	19,744		165
Other	10			10
Total	$ 73,942	$ 73,120	$ (15)	$ 837
For the three months ended June 30, 2001				
United States	$ 39,957	$ 39,330	$ 63	$ 564
Kingdom of Thailand	12,682	12,536		146
Canada and other	825	816		9
Total	$ 53,464	$ 52,682	$ 63	$ 719
For the six months ended June 30, 2002				
United States	$ 103,302	$ 102,020	$ (6)	$ 1,288
Kingdom of Thailand	36,404	36,074		330
Other	42			42
Total	$ 139,748	$ 138,094	$ (6)	$ 1,660
For the six months ended June 30, 2001				
United States	$ 62,696	$ 61,735	$ 122	$ 839
Kingdom of Thailand	26,109	25,877		232
Canada and other	1,727	1,709		18
Total	$ 90,532	$ 89,321	$ 122	$ 1,089
Operating Income (Loss):				
For the three months ended June 30, 2002				
United States	$ 41,504	$ 42,400	$ (20)	$ (876)
Kingdom of Thailand	19,114	19,098		16
Other	(440)			(440)
Total	$ 60,178	$ 61,498	$ (20)	$ (1,300)
For the three months ended June 30, 2001				
United States	$ 40,664	$ 40,298	$ (52)	$ 418
Kingdom of Thailand	17,027	17,017		10
Canada and other	(3,270)	(3,285)		15
Total	$ 54,421	$ 54,030	$ (52)	$ 443
For the six months ended June 30, 2002				

United States	$ 55,178	$ 55,657	$ (142)	$ (337)
Kingdom of Thailand	35,234	35,219		15
Other	(955)			(955)
Total	$ 89,457	$ 90,876	$ (142)	$ (1,277)
For the six months ended June 30, 2001				
United States	$ 99,311	$ 97,261	$ (130)	$ 2,180
Kingdom of Thailand	40,774	40,715		59
Canada and other	(8,640)	(8,633)		(7)
Total	$ 131,445	$ 129,343	$ (130)	$ 2,232

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 June 30, 2002			Six Months Ended June 30, 2002		
	Income	**Shares**	**Per Share**	**Income**	**Shares**	**Per Share**
Basic earnings per share	$ 28,618	56,192	$ 0.51	$ 37,643	54,972	$ 0.68
Effect of dilutive securities:						
Options to purchase common shares		1,005			871	
2006 Notes	1,028	2,726				
Trust Preferred Securities	1,108	4,417		2,693	5,367	
Diluted earnings per share	$ 30,754	64,340	$ 0.48	$ 40,336	61,210	$ 0.66
Antidilutive securities						
Options to purchase common shares		138	$ 38.19		173	$ 36.77
2006 Notes				2,056	2,726	$ 0.75

	Three Months Ended June 30, 2001			Six Months Ended June 30, 2001		
	Income	**Shares**	**Per Share**	**Income**	**Shares**	**Per Share**
Basic earnings per share	$ 30,979	53,575	$ 0.58	$ 70,925	48,425	$ 1.46
Effect of dilutive securities:						
Options to purchase common shares		877			906	
2006 Notes	1,028	2,726		2,056	2,726	
Trust Preferred Securities	1,584	6,316		3,169	6,316	
Diluted earnings per share	$ 33,591	63,494	$ 0.53	$ 76,150	58,373	$ 1.31
Antidilutive securities						
Options to purchase common shares		307	$ 33.86		307	$ 33.86

(7) RECENT ACCOUNTING PRONOUNCEMENT

The Financial Accounting Standards Board has recently issued a new pronouncement, Statement of Financial Accounting Standards No. 143 (SFAS 143), Accounting for Asset Retirement Obligations . 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 currently intends to adopt this standard 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 quantified the financial statement impact from adoption of this new standard.

(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

POGO PRODUCING COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

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.

	Six Months Ended June 30, 2001
Revenues	$ 402,236
Net income	$ 87,319
Earnings per share	
Basic	$ 1.63
Diluted	$ 1.46

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. Certain statements contained herein 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, such 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 previously announced 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. As of June 4, 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. In response to SEC Release No. 33-8040, Cautionary Advice Regarding Disclosure About Critical Accounting Policies, we have identified certain of these policies as being 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 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 incurred to select development locations within an oil and gas field is typically treated as a development cost 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 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 expected therefrom 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 such 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 to other properties in all four comparative 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. 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. 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 or 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 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. Such estimates 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 estimates of 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.

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 earning 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 are utilized in the cash flow projections that may be revised 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 are utilized in the assessments that may be revised in the future.

Results of Operations

Net income

The Company reported net income for the second quarter of 2002 of $28,618,000 or $0.51 per share ($30,754,000 or $0.48 per share on a diluted basis), compared to net income for the second quarter of 2001 of $30,979,000 or $0.58 per share ($33,591,000 or $0.53 per share on a diluted basis). For the first six months of 2002, the Company reported net income of $37,643,000 or $0.68 per share ($40,336,000 or $0.66 per share on a diluted basis) compared to net income for the first six months of 2001 of $70,925,000 or $1.46 per share ($76,150,000 or $1.31 per share on a diluted basis). The decrease in net income during the second quarter and first six months of 2002, compared to the second quarter and first six 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, partially offset by increased 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 second quarter and first six months of 2002, compared to the second quarter and first six months of 2001, was also negatively impacted 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 half of 2002. Conversely, net income reported in the first six months of 2001 was positively impacted by a gain on the sale of certain non-strategic properties, all of which were recognized in the first quarter of 2001.

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 second quarter and first six months of 2002, compared to the second quarter and first six 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 computation on a diluted basis for all periods presented 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 the second quarter of 2002, and the second quarter and first six months 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 second quarter of 2002 were $184,385,000, an increase of approximately 9% from total revenues of $169,394,000 for the second quarter of 2001. The Company s total revenues for the first six months of 2002 were $327,295,000, a decrease of approximately 3% compared to total revenues of $339,256,000 for the first six months of 2001. The increase in the Company s total revenues for the second quarter of 2002, compared to the second quarter of 2001, resulted primarily from an increase in oil and gas revenues, partially offset by a decrease in pipeline sales and a loss on sales of properties, both of which were attributable to the Company s sale of certain non-strategic properties. The decrease in the Company s total revenues for the first six months of 2002, compared to the first six months of 2001, resulted primarily from a decrease in pipeline sales and a loss on sales of properties, both of which were attributable to the Company s sale of certain non-strategic properties and, to a much lesser extent, a slight decrease in oil and gas revenues.

Oil and Gas Revenues

The Company s oil and gas revenues for the second quarter of 2002 were $185,241,000, an increase of approximately 13% from oil and gas revenues of $164,412,000 for the second quarter of 2001. The Company s oil and gas revenues for the first six months of 2002 were $327,538,000, a slight decrease from oil and gas revenues of $328,325,000 for the first six 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:

	2nd Qtr 2002 Compared to 2nd Qtr 2001	1st Half 2002 Compared to 1st Half 2001
Increase (decrease) in oil and gas revenues resulting from variances in:		
Natural gas		
Price	$ (27,882)	$ (76,890)
Production	3,771	24,234
	(24,111)	(52,656)
Crude oil and condensate		
Price	(6,482)	(22,359)
Production	47,960	68,685
	41,478	46,326
Natural Gas Liquids (NGL)	3,462	5,543
Increase (decrease) in oil and gas revenues	$ 20,829	$ (787)

The increase in the Company s oil and gas revenues for the second quarter of 2002, compared to the second quarter of 2001, is primarily related to increases in the Company s oil and condensate, natural gas and NGL production volumes, that were partially offset by the decrease in the prices received for natural gas, crude oil and condensate production. The slight decrease in the Company s oil and gas revenues for the first half of 2002, compared to the first half of 2001, is primarily related to lower prices received for the Company s natural gas production and, to a lesser extent, crude oil and condensate production, which more than offset the higher production volumes for the Company s crude oil, condensate, natural gas and NGL production.

	2nd Quarter			1st Six Months		
	2002	2001	% Change	2002	2001	% Change
Comparison of Increases (Decreases) in:						
Natural Gas						
Average prices						
North America(a)	**$ 3.21**	$ 4.62	**(31)%**	**$ 3.01**	$ 5.53	**(46)%**
Kingdom of Thailand(b)	**$ 2.12**	$ 2.24	**(5)%**	**$ 2.22**	$ 2.34	**(5)%**
Company-wide average price	**$ 2.91**	$ 4.04	**(28)%**	**$ 2.79**	$ 4.66	**(40)%**
Average daily production volumes (MMcf per day)						
North America(a)	**206.1**	205.0	**1%**	**198.6**	165.4	**20%**
Kingdom of Thailand	**79.5**	66.1	**20%**	**76.3**	61.8	**23%**
Company-wide average daily production	**285.6**	271.1	**5%**	**274.9**	227.2	**21%**

	2nd Quarter			1st Six Months		
	2002	2001	% Change	2002	2001	% Change
Comparison of Increases (Decreases) in:						
Crude Oil and Condensate						
Average prices(c)						
North America	**$ 24.28**	$ 25.84	**(6)%**	**$ 22.39**	$ 26.86	**(17)%**
Kingdom of Thailand	**$ 24.32**	$ 28.21	**(14)%**	**$ 22.09**	$ 26.37	**(16)%**
Company-wide average price	**$ 24.29**	$ 26.75	**(9)%**	**$ 22.29**	$ 26.64	**(16)%**
Average daily production volumes (Bbls per day)						
North America(c)	**30,659**	15,514	**98%**	**28,862**	14,719	**96%**
Kingdom of Thailand(d)	**15,715**	13,442	**17%**	**16,114**	13,679	**18%**
Company-wide average daily production	**46,374**	28,956	**60%**	**44,976**	28,398	**58%**
Total Liquid Hydrocarbons						
Company-wide average daily production (Bbls per day)(d)	**51,400**	31,028	**66%**	**49,299**	29,790	**65%**

(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. 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. Bbls is an abbreviation for barrels. 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).

(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 3,000 barrels less than it sold in the second quarter of 2002 and 165,000 barrels more than it sold in the first six months of 2002. It produced 351,000 and 205,000 barrels more than it sold in the second quarter and first six 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 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 second quarter and first six months of 2002, compared to the second quarter and first six months of 2001, reflects positive adjustments related to base production sold under the gas sales agreement that were more than offset by 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 second quarter of 2002, compared to the second 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, partially offset by natural production declines at certain other properties. The increase in the Company s domestic natural gas production during the first six months of 2002, compared to the first six 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 certain other properties.

Thailand Production. The increase in the Company s Thailand natural gas production during the second quarter and first six months of 2002, compared to the second quarter and first six 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. In addition, 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 second quarter and first six months of 2002, compared to the second quarter and first six months of 2001, primarily related to commencement of production from the Company s Main Pass Blocks 61/62 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 second quarter and first six months of 2002, compared to the second quarter and first six 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 currently anticipates that production facilities upgrades at Benchamas Field, scheduled for the third quarter 2002, could require 20-25 days to accomplish and will likely reduce the Company s net third quarter 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 2,000 barrels less than it sold in the second quarter of 2002 and 165,000 barrels more than it sold in the first six months of 2002. It produced 351,000 and 205,000 barrels more than it sold in the second quarter and first six months of 2001, respectively. As of June 30, 2002, the Company had approximately 424,000 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 second quarter and first six months of 2002, compared with the second quarter and first six months of 2001, primarily related to NGL removed from the Company s Mississippi Canyon Blocks 661/705 Field gas production and, to a lesser extent, the decision by the Company to extract NGL from a higher percentage of its other natural gas production due to favorable economics. 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

	2nd Quarter			**1st Six Months**		
	2002	**2001**	**% Change**	**2002**	**2001**	**% Change**
Comparison of Increases (Decreases) in:						
Lease Operating Expenses						
North America	**$ 24,505,000**	$ 22,721,000	**8%**	**$ 47,271,000**	$ 39,771,000	**19%**
Kingdom of Thailand	**$ 10,080,000**	$ 6,975,000	**45%**	**$ 18,597,000**	$ 15,752,000	**18%**
Total Lease Operating Expenses	**$ 34,585,000**	$ 29,696,000	**16%**	**$ 65,868,000**	$ 55,523,000	**19%**
Pipeline Operating and Natural Gas Purchases	**$**	$ 4,400,000	**N/M**	**$ 181,000**	$ 8,420,000	**(98)%**
General and Administrative Expenses	**$ 10,828,000**	$ 9,650,000	**12%**	**$ 22,370,000**	$ 17,858,000	**25%**
Exploration Expenses	**$ 1,352,000**	$ 5,486,000	**(75)%**	**$ 1,176,000**	$ 12,434,000	**(91)%**
Dry Hole and Impairment Expenses	**$ 3,500,000**	$ 12,277,000	**(72)%**	**$ 8,495,000**	$ 23,044,000	**(63)%**
Depreciation, Depletion and Amortization (DD&A) Expenses	**$ 73,942,000**	$ 53,464,000	**38%**	**$ 139,748,000**	$ 90,532,000	**54%**
DD&A rate	**$ 1.37**	$ 1.33	**3%**	**$ 1.37**	$ 1.24	**10%**
Mcfe sold(a)	**54,065,000**	39,509,000	**37%**	**102,299,000**	72,241,000	**42%**
Interest						
Charges	**$ (14,500,000)**	$ (14,988,000)	**(3)%**	**$ (29,088,000)**	$ (26,292,000)	**11%**
Interest Income	**$ 534,000**	$ 694,000	**(23)%**	**$ 912,000**	$ 1,996,000	**(54)%**
Capitalized Interest Expense	**$ 6,859,000**	$ 10,303,000	**(33)%**	**$ 13,512,000**	$ 14,829,000	**(9)%**
Minority Interest Dividends and Costs	**$ (1,638,000)**	$ (2,501,000)	**(35)%**	**$ (4,140,000)**	$ (4,998,000)	**(17)%**
Foreign Currency Transaction Gain (Loss)	**$ 659,000**	$ (421,000)	**N/M**	**$ 1,331,000**	$ (1,006,000)	**N/M**
Income Tax Expense	**$ (23,474,000)**	$ (16,529,000)	**42%**	**$ (34,341,000)**	$ (45,049,000)	**(24)%**

(a) Mcfe represents thousands of cubic feet equivalent.

Lease Operating Expenses.

The increase in North American lease operating expenses for the second quarter and first six months of 2002, compared to the second quarter and first six months of 2001, primarily related to increased costs associated with the acquisition of North Central and increased product transportation and processing expenses related to increased production from the Company s Gulf of Mexico properties, partially offset by decreased severance taxes and lease maintenance costs in the Gulf of Mexico and the Company s Western Division properties.

The increase in lease operating expenses in the Kingdom of Thailand for the second quarter and first six months of 2002, compared to the second quarter and first six months of 2001, primarily related to increased rental expenses for compressors and other equipment, increased insurance costs and a decrease in the amount of lifting costs carried as product inventory. 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 $3,625,000 and $7,211,000 (net to the Company s interest) of the Company s Thailand lease operating expenses for the second quarter and first six 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 $0.75 per Mcfe for the second quarter and $0.77 per Mcfe for the first six months of 2001 to $0.64 per Mcfe for both the second quarter and first six months of 2002, due to the increased production discussed previously.

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 for resale, together with the costs of operating the pipeline carrying the natural gas, is recorded as an expense under Pipeline operating and natural gas purchases. 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. Consequently, there is no meaningful comparison between the quarterly and six month periods for 2001 and 2002.

General and Administrative Expenses

The increase in general and administrative expenses for the second quarter of 2002, compared with the second quarter of 2001, related to increased expenses associated with the Company s acquisition of North Central and its employees, as well as an increase in the size of the Company s work force and normal salary and concomitant benefit expense adjustments. The increase in general and administrative expenses for the first six months of 2002, compared with the first six months of 2001, related to increased expenses associated with the Company s acquisition of North Central and its employees, as well as an increase in the size of the Company s work force and normal salary and concomitant benefit expense adjustments. 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 $0.24 per Mcfe for the second quarter and $0.25 per Mcfe for the first six months of 2001, to $0.20 per Mcfe for the second quarter and $0.22 per Mcfe for the first six 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 second quarter and first six months of 2002, compared to the second quarter and first six months of 2001, resulted primarily from a decrease in 3-D seismic acquisition activities during the 2002 periods and, to a lesser extent, the rebate of a delay rental ($1,327,000 net to the Company) that was paid by the Company s Thai subsidiary to the Kingdom of Thailand, which was returned when certain contractual obligations under the Company s concession license were satisfied. Exploration expenses for the second quarter and first six months of 2001 included the cost of conducting two major 3-D projects in Hungary and seismic operations in Canada and the Gulf of Mexico, for which no comparable expenses were experienced during the same periods in 2002.

Dry Hole and Impairment

The decrease in the Company s dry hole and impairment expense for the second quarter and first six months of 2002, compared to the second quarter and first six months of 2001, resulted from a decrease in the cost of the Company s unsuccessful exploratory wells, and a reduction in the number and value of properties that were impaired during the 2002 periods, as compared to the 2001 periods.

Depreciation, Depletion and Amortization Expenses

The increase in the Company s depreciation, depletion and amortization (DD&A) expense for the second quarter and first six months of 2002, compared to the second quarter and first six months of 2001, resulted primarily from an increase in the Company s natural gas and liquid hydrocarbon production and, to a lesser extent, an increase in the Company s composite DD&A rate.

The slight increase in the composite DD&A rate for all of the Company s producing fields for the second quarter of 2002, compared to the second quarter of 2001, was primarily attributable to increased production from fields with a DD&A rate higher than the Company s recent historic average. The increase in the composite DD&A rate for all of the Company s producing fields for the first six months of 2002, compared to the first six 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 (principally the new Main Pass Blocks 61/62 Field and its Benchamas Field).

Interest

Interest Charges. The decrease in the Company s interest charges for the second quarter of 2002, compared to the second 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 six months of 2002, compared to the first six 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 by a charge for amortization of debt issuance costs incurred in the first half of 2001 for which no comparable charges were taken during 2002. 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 second quarter and first six months of 2002, compared to the second quarter and first six 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. Except for working capital needs, a significant portion of the Company s cash and cash equivalents were used to fund the

North Central acquisition. The cash and cash equivalents on the Company s balance sheet at June 30, 2002, are primarily held by the Company s international subsidiaries for future investment overseas.

Capitalized Interest. The decrease in capitalized interest for the second quarter of 2002, compared to the second quarter of 2001, resulted primarily from a decrease in the average amount of capital expenditures subject to interest capitalization (approximately $381,000,000 in the second quarter of 2002, compared to approximately $528,000,000 in the second 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 six months of 2002, compared to the first six 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 six months of 2002, compared to approximately $366,000,000 in the first six 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 owns 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. As of June 4, 2002, there were no Trust Preferred Securities outstanding. The amounts recorded for the second quarter and first six months of 2001 and 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 second quarter and first six months of 2002, and the losses reported for the second quarter and first six 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 July 22, 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 second quarter of 2002, compared to the second quarter of 2001, resulted primarily from increased pre-tax income and, to a lesser extent, an increase in the Company s effective tax rate resulting from higher pre-tax income derived from the Company s Thailand operations during the quarterly comparative periods, relative to its pre-tax income from North American operations. The decrease in the Company s tax expense for the first six months of 2002, compared to the corresponding six months of 2001, resulted primarily from decreased pre-tax income, partially offset by an increase in the Company s effective tax rate due to higher pre-tax income derived from the Company s Thailand operations, relative to its pre-tax income from

North American operations. Management currently expects that its 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 six months of 2002 reflects net cash provided by operating activities of $210,837,000. In addition to net cash provided by operating activities, the Company received $14,321,000 from financing and other activities, primarily from the exercise of stock options.

During the first six months of 2002, the Company invested $175,673,000 in capital projects, repaid a net $25,003,000 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 $3,240,000 ($0.06 per share) in cash dividends to holders of the Company s common stock and paid $130,000 in financing issue costs. As of July 22, 2002, the Company s cash and cash equivalents were $99,173,000 and its long-term debt stood at $766,942,000. In addition, the Company had $198,000,000 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, was recently increased by the Company s Board of Directors to $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 August 16, 2002 to shareholders of record on August 2, 2002). The declaration of future dividends on the Company s equity securities will depend upon, among other things, the Company s future earnings and financial condition, liquidity and capital requirements, its ability to pay dividends and distributions under certain covenants contained in its debt instruments, the general economic and regulatory climate and other factors deemed relevant by the Company s Board of Directors.

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 June 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	$ 320.0	$ 450.0	$ 770.0
Operating Leases(a)	$ 11.7	$ 21.8	$ 21.8	$ 21.6	$ 21.4	$ 64.0	$ 162.3
Drilling obligations(b)	$ 0.3	$ 0.1	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.4
Firm transportation agreements(c)	$ 0.6	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 5.1	$ 10.5
Total	$ 12.6	$ 23.1	$ 23.0	$ 22.8	$ 342.6	$ 519.1	$ 943.2

(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 commitment for a single rig drilling in the Madden Field in Wyoming. 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 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 June 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.

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 July 22, 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 June 30, 2002:

	2002	2003	2004	2005	2006	Thereafter	Total	Fair Value
Long-Term Debt:								
Variable Rate	$ 0	$ 0	$ 0	$ 0	$ 205,000	$ 0	$ 205,000	$ 205,000
Average Interest Rate					3.07%		3.07%	
Fixed Rate	$ 0	$ 0	$ 0	$ 0	$ 115,000	$ 450,000	$ 565,000	$ 573,338
Average Interest Rate					5.5%	7.13%	6.79%	

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 July 22, 2002, the Company is not a party to any foreign currency exchange 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.

Natural Gas

As of June 30, 2002, the Company held options to sell 70 million cubic feet of natural gas production per day for the period from July 1, 2002 through December 31, 2002 at a sales price of $4.00 per million British thermal units (MMBtu). The Company has designated these contracts as cash flow hedges designed to give the Company the right, but not the obligation, to sell natural gas at a sales price of $4.00 per MMBtu through December 2002. These contracts are designed to guarantee a minimum floor price for the contracted volumes of production without limiting the Company s participation in price increases during the covered period. Further details related to the Company s hedging activities are as follows:

Contract Period	Volume in MMBtu	NYMEX Contract Price per MMBtu	Fair Market Value(a)
Floor Contract:			
July 2002 December 2002	12,880	$ 4.00	$ 8,665,000

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(a) Fair Market Value is calculated using prices derived from NYMEX futures contract prices existing at June 30, 2002.

These hedging transactions are settled based upon the average of the reported settlement prices on the NYMEX for the last three trading days or, occasionally, the penultimate trading day of a particular contract month. For any particular floor transaction, the counter-party 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 transaction.

Crude Oil

As of July 22, 2002, the Company was not a party to any commodity price hedging contracts with respect to any of its current or future crude oil and condensate production.

PART II. OTHER INFORMATION

Item 4. ***Submission of Matters to a Vote of Security-Holders***

The registrant held its annual meeting of stockholders in Houston, Texas on April 23, 2002. The following sets forth the items that were put to a vote of the stockholders and the results thereof concerning:

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

Nominee	For	Withheld
Jerry M. Armstrong	48,482,849	242,430
Robert H. Campbell	48,488,052	237,727
Stephen A. Wells	48,182,397	542,882

(B) a proposal to approve the Company s 2002 Incentive Plan, with 48,725,279 shares of stock cast for approval, 1,442,319 shares against approval and 42,279 shares were withheld and therefore, pursuant to Delaware law, were considered votes against the proposal.

Item 6. ***Exhibits and Reports on Form 8-K***

(A) *Exhibits*

4.1 Amended and Restated Bylaws of Pogo Producing Company, as amended and restated on July 16, 2002.

(B) *Reports on Form 8-K*

Report filed on May 17, 2002, announcing a change in the independent auditors for the Company s Tax Advantaged Savings Plan on May 17, 2002 under Item 4 and attaching one exhibit under Item 7.

Report filed on April 17, 2002, announcing a change in the Company s independent auditors on April 15, 2002 under Item 4 and attaching one exhibit under Item 7.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

POGO PRODUCING COMPANY
(Registrant)

By: /s/ THOMAS E. HART

Thomas E. Hart
Vice President and Chief Accounting Officer

By: /s/ JAMES P. ULM, II

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

Date: July 25, 2002