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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

☒ **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

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ______________ to ______________

Commission file number: 0-7062

NOBLE ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware *(State of incorporation)*	**73-0785597** *(I.R.S. employer identification number)*
350 Glenborough Drive, Suite 100 **Houston, Texas** *(Address of principal executive offices)*	**77067** *(Zip Code)*

(281) 872-3100
(Registrant's telephone number, including area code)

NOBLE AFFILIATES, INC.
(Registrant's former name)

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 requirements for the past 90 days.

Yes ☒ No o

Number of shares of common stock outstanding as of July 31, 2002: 57,287,570

PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

NOBLE ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED CONDENSED BALANCE SHEET
(Dollars in thousands)

	(Unaudited) June 30, 2002	December 31, 2001
ASSETS		
Current Assets:		
Cash and short-term investments	$ 1,681	$ 73,237
Accounts receivable-trade	168,621	182,979
Oil and gas price risk management receivable	6,799	33,424
Materials and supplies inventories	10,745	10,828

Other current assets	21,800	51,103
Total Current Assets	209,646	351,571
Property, Plant and Equipment, at cost	4,134,013	3,974,754
Less: accumulated depreciation, depletion and amortization	(2,089,679)	(2,021,543)
Total property, plant and equipment, net	2,044,334	1,953,211
Investment in Unconsolidated Subsidiary	236,763	117,735
Other Assets	72,829	57,331
Total Assets	$ 2,563,572	$ 2,479,848
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable-trade	$ 232,415	$ 270,091
Short-term note payable	24,775	25,000
Current installments of long-term debt	46,378	19,507
Oil and gas price risk management payable	8,512	25,363
Other current liabilities	38,171	40,624
Total Current Liabilities	350,251	380,585
Deferred Income Taxes	180,535	176,259
Other Deferred Credits and Noncurrent Liabilities	77,533	75,629
Long-Term Debt	947,012	837,177
Shareholders' Equity:		
Common stock	199,240	198,369
Capital in excess of par value	402,905	396,104
Retained earnings	447,443	449,985
Accumulated other comprehensive income (loss)	(2,017)	5,070
	1,047,571	1,049,528
Less Common Stock in Treasury (at cost, 2,505,522 shares)	(39,330)	(39,330)
Total Shareholders' Equity	1,008,241	1,010,198
Total Liabilities and Shareholders' Equity	$ 2,563,572	$ 2,479,848

See notes to consolidated condensed financial statements.

NOBLE ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED CONDENSED STATEMENT OF OPERATIONS
(Dollars in Thousands, Except Per Share Amounts)
(Unaudited)

	Three Months Ended June 30,	
	2002	**2001**
REVENUES:		
Oil and gas sales and royalties	$ 181,359	$ 229,644
Gathering, marketing and processing	152,548	184,348
Loss from unconsolidated subsidiary	(3,480)	(1,044)
Other income (loss)	(135)	520
	330,292	413,468
COSTS AND EXPENSES:		
Oil and gas operations	33,507	32,675
Oil and gas exploration	20,233	26,777

Gathering, marketing and processing	150,522	181,645
Depreciation, depletion and amortization	73,049	76,869
Selling, general and administrative	12,083	10,691
Interest	16,694	9,287
Interest capitalized	(4,732)	(3,916)
	301,356	334,028
INCOME BEFORE TAXES	28,936	79,440
INCOME TAX PROVISION	11,817(1)	28,106(1)
NET INCOME	$ 17,119	$ 51,334
BASIC EARNINGS PER SHARE	$ .30(2)	$ .91(2)
DILUTED EARNINGS PER SHARE	$ .30(2)	$ .89(2)

See notes to consolidated condensed financial statements.

NOBLE ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED CONDENSED STATEMENT OF OPERATIONS
(Dollars in Thousands, Except Per Share Amounts)
(Unaudited)

	Six Months Ended June 30,	
	2002	**2001**
REVENUES:		
Oil and gas sales and royalties	$ 327,431	$ 545,990
Gathering, marketing and processing	321,544	427,969
Loss from unconsolidated subsidiary	(3,905)	(747)
Other income	2,872	1,270
	647,942	974,482
COSTS AND EXPENSES:		
Oil and gas operations	70,655	66,568
Oil and gas exploration	56,638	65,291
Gathering, marketing and processing	317,822	421,675
Depreciation, depletion and amortization	148,551	141,112
Selling, general and administrative	23,406	22,481
Interest	32,113	19,736
Interest capitalized	(9,083)	(6,804)
	640,102	730,059
INCOME BEFORE TAXES	7,840	244,423
INCOME TAX PROVISION	5,819(1)	87,180(1)
NET INCOME	$ 2,021	$ 157,243
BASIC EARNINGS PER SHARE	$ .04(2)	$ 2.79(2)
DILUTED EARNINGS PER SHARE	$ .03(2)	$ 2.74(2)

See notes to consolidated condensed financial statements.

NOBLE ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
AND SHAREHOLDERS' EQUITY

(Dollars in Thousands)
(Unaudited)

	Comprehensive Income (Loss)	Common Stock	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock At Cost	Total Shareholders' Equity
Balance at December 31, 2001		$ 198,369	$ 396,104	$ 449,985	$ 5,070	$ (39,330)	$ 1,010,198
Net income	$ 2,021			2,021			2,021
Reclassification of unrealized gains on securities to net income, net of $1,313 income tax	2,438				2,438		2,438
Change in fair value of cash flow hedges, net of income tax	(9,525)				(9,525)		(9,525)
Shares issued		871	6,801				7,672
Dividends declared ($.08 per share)				(4,563)			(4,563)
Total	$ (5,066)						
Balance at June 30, 2002		$ 199,240	$ 402,905	$ 447,443	$ (2,017)	$ (39,330)	$ 1,008,241

See notes to consolidated condensed financial statements.

NOBLE ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED CONDENSED STATEMENT OF CASH FLOWS
(Dollars in Thousands)
(Unaudited)

	Six Months Ended June 30, 2002	Six Months Ended June 30, 2001
Cash Flows from Operating Activities:		
Net income	$ 2,021	$ 157,243
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	148,551	141,112
Dry hole	30,244	45,241
Amortization of undeveloped lease costs	7,717	7,344
(Gain) loss on disposal of assets	(2,556)	34
Deferred income taxes	4,276	24,474
Loss from unconsolidated subsidiary	3,905	747
Dividends received from unconsolidated subsidiary	488	
Increase (decrease) in deferred credits	1,904	33,810
(Increase) decrease in other	(14,046)	(9,633)
Changes in working capital, not including cash:		
(Increase) decrease in accounts receivable	14,358	21,187
(Increase) decrease in other current assets and inventories	30,709	(48,989)
Increase (decrease) in accounts payable	(37,676)	1,483
Increase (decrease) in other current liabilities	(2,452)	(7,541)
Net Cash Provided by Operating Activities	187,443	366,512
Cash Flows From Investing Activities:		
Capital expenditures	(295,096)	(365,077)
Investment in unconsolidated subsidiary	(6,844)	(42,120)
Proceeds from sale of property, plant and equipment	20,016	150
Distribution from unconsolidated subsidiary	5,500	
Net Cash Used in Investing Activities	(276,424)	(407,047)
Cash Flows From Financing Activities:		
Exercise of stock options	7,672	16,523

Cash dividends	(4,563)	(4,514)
Proceeds from bank debt	122,842	180,000
Repayment of bank debt	(95,000)	(110,000)
Repayment of note payable obtained on Aspect acquisition	(13,526)	
Net Cash Provided by Financing Activities	17,425	82,009
Increase (Decrease) in Cash and Short-term Investments	(71,556)	41,474
Cash and Short-term Investments at Beginning of Period	73,237	23,152
Cash and Short-term Investments at End of Period	$ 1,681	$ 64,626
Supplemental Disclosures of Cash Flow Information:		
Cash paid (received) during the period for:		
Interest (net of amount capitalized)	$ 13,801	$ 14,162
Income taxes paid (refunded)	$ (40,394)	$ 66,131
Debt obtained from consolidation of AMCCO (net of discount)	$ 122,510	$

See notes to consolidated condensed financial statements.

NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS

(Unaudited)

In the opinion of Noble Energy, Inc. (the "Company"), the accompanying unaudited consolidated condensed financial statements contain all adjustments, consisting only of necessary and normal recurring adjustments, necessary to present fairly the Company's financial position as of June 30, 2002 and December 31, 2001; the results of operations for the three month and six month periods ended June 30, 2002 and 2001, respectively; the statement of comprehensive income and equity for the six month period ended June 30, 2002; and the cash flows for the six month periods ended June 30, 2002 and 2001. These consolidated condensed financial statements should be read in conjunction with the consolidated financial statements and the notes thereto included in the Company's annual report on Form 10-K for the year ended December 31, 2001.

(1) INCOME TAX PROVISION

For the three months ended June 30:

	2002	2001
	(In thousands)	
Current	$ 5,981	$ 13,923
Deferred	5,836	14,183
	$ 11,817	$ 28,106

For the six months ended June 30:

	2002	2001
	(In thousands)	
Current	$ 1,543	$ 62,706
Deferred	4,276	24,474
	$ 5,819	$ 87,180

(2) BASIC EARNINGS PER SHARE AND DILUTED EARNINGS PER SHARE

Basic earnings per share of common stock was computed using the weighted average number of shares of common stock outstanding during each period. The diluted net income per share of common stock includes the effect of outstanding stock options.

The following table summarizes the calculation of basic earnings per share ("EPS") and diluted EPS.

For the three months ended June 30:

(in thousands, except per share)	2002 Income (Numerator)		2002 Shares (Denominator)	2001 Income (Numerator)		2001 Shares (Denominator)
Net income/shares	$ 17,119		57,171	$ 51,334		56,590
Basic EPS		$ .30			$ .91	
Net income/shares	$ 17,119		57,171	$ 51,334		56,590
Effect of Dilutive Securities						
Stock options			724			822
Adjusted net income/shares	$ 17,119		57,895	$ 51,334		57,412
Diluted EPS		$ .30			$ .89	

For the six months ended June 30:

(in thousands, except per share)	2002 Income (Numerator)		2002 Shares (Denominator)	2001 Income (Numerator)		2001 Shares (Denominator)
Net income/shares	$ 2,021		57,094	$ 157,243		56,455
Basic EPS		$ .04			$ 2.79	
Net income/shares	$ 2,021		57,094	$ 157,243		56,455
Effect of Dilutive Securities						
Stock options			658			1,004
Adjusted net income/shares	$ 2,021		57,752	$ 157,243		57,459
Diluted EPS		$ .03			$ 2.74	

(3) TRADING AND HEDGING ACTIVITIES

The Company, through its subsidiaries, from time to time, uses various price risk management arrangements in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations. Such arrangements include fixed price forward sales, costless collars and other contractual arrangements. Although these arrangements expose the Company to credit risk, the Company takes reasonable steps to protect itself from nonperformance by its counterparties; however, the Company is not able to predict sudden changes in its counterparties' creditworthiness. Gains and losses from such arrangements related to the Company's oil and gas production and which qualify for

hedge accounting treatment are recorded in oil and gas sales and royalties upon sale of the associated products.

During the second quarter of 2002, the Company entered into various natural gas costless collars, natural gas costless collar combinations and crude oil costless collar transactions related to its production.

In second quarter 2002, the natural gas costless collars were for 80,000 MMBTU of natural gas per day, with floor prices ranging from $2.75 to $3.25 per MMBTU and ceiling prices ranging from $3.50 to $5.10 per MMBTU; the costless collar combinations were for 100,000 MMBTU of natural gas per day, with floor prices ranging from $2.00 to $2.25 per MMBTU and ceiling prices ranging from $2.95 to $3.10 per MMBTU, with a $.25 to $.30 premium to index on prices below the floors. The realized effect of the natural gas arrangements on gas sales for the second quarter was a decrease of $.06 per MCF. For the first six months of 2002, the Company had natural gas costless collars for 160,387 MMBTU per day, with floor prices ranging from $2.00 to $3.25 per MMBTU and ceiling prices ranging from $2.45 to $5.10 per MMBTU. The realized effect of the costless collar transactions for the first six months of 2002 in the average natural gas price was an increase of $.03 per MCF.

The crude oil costless collars for the second quarter were for 110 BBLS of oil per day, with a floor price of $24.00 per BBL and a ceiling price of $29.40 per BBL. There was no realized effect on oil sales for second quarter 2002 for these costless collars.

In addition, the Company has entered into natural gas arrangements to support the Company's investment program for the periods: July to September 2002, costless collars for 120,000 MMBTU of natural gas per day, with floor prices ranging from $2.75 to $3.25 per MMBTU and ceiling prices ranging from $3.50 to $5.10 per MMBTU; July to September 2002, costless collar combinations for 75,000 MMBTU of natural gas per day, with floor prices ranging from $3.00 to $3.25 per MMBTU and ceiling prices ranging from $4.30 to $5.00 per MMBTU, with a $.50 premium to index price on prices below the floor prices; October to December 2002, costless collars for 115,000 MMBTU of natural gas per day, with floor prices ranging from $3.00 to $3.50 per MMBTU and ceiling prices ranging from $3.75 to $5.05 per MMBTU. Of the 120,000 MMBTU of natural gas per day costless collars for July to September 2002 and of the 115,000 MMBTU of natural gas per day costless collars for October to December 2002, 60,000 MMBTU for the third quarter and 25,000 MMBTU for the fourth quarter 2002 of natural gas per day were terminated and, as a result, the Company will recognize an additional $.70 to $.34 per MMBTU on the 60,000 to 25,000 MMBTU of natural gas per day in the third and fourth quarters of 2002, respectively.

The Company has entered into various crude oil costless collar transactions for July to September 2002 for 10,000 BBLS of oil per day, with floor prices ranging from $23.00 to $24.00 per BBL and ceiling prices ranging from $29.30 to $30.00 per BBL.

The Company has costless collar transactions related to calendar year 2003 for 45,000 MMBTU of natural gas production per day with a floor price of $3.25 per MMBTU and a ceiling price of $4.00 per MMBTU.

The Company assumed swaps related to the acquisition of Aspect Resources, Inc. that cover the period January 2002 to March 2004 for 5,116 MMBTU of natural gas production per day and 124 BBLS of oil production per day. Based on the cost of these swaps, the Company will realize prices of approximately $3.20 per MMBTU and $22.00 per BBL for this time period related to these volumes.

There was no realized effect on the average gas price and a realized effect of a $.03 per BBL decrease in the average crude oil price in the second quarter of 2002 due to the purchased swaps. The realized effect of the purchased swaps for the first six months of 2002 was an increase of $.02 per MCF and a decrease of $.01 per BBL in the average natural gas and crude oil prices.

During the second quarter of 2001, the Company had no price risk management arrangements for its production other than those entered into by Noble Gas Marketing, Inc. ("NGM"), which are described below.

NGM employs various price risk management arrangements in connection with its purchases and sales of third party production to lock in profits or limit exposure to gas price risk. Most of the purchases made by NGM are on an index basis; however, purchasers in the markets in which NGM sells often require fixed or NYMEX related pricing. NGM may use a hedge to convert the fixed or NYMEX sale to an index basis thereby determining the margin and minimizing the risk of price volatility.

NGM records hedging gains or losses relating to fixed term sales as gathering, marketing and processing revenues in the periods in which the related contract is completed.

At June 30, 2002, the Company recorded oil and gas hedge receivables of $9.3 million, oil and gas hedge liabilities of $12.6 million and other comprehensive loss, net of tax, of $2.0 million related to the Company's cash flow hedging contracts.

(4) METHANOL PLANT

Prior to January 2002, Atlantic Methanol Capital Company ("AMCCO"), was a 50 percent owned joint venture that owned an indirect 90 percent interest in Atlantic Methanol Production Company ("AMPCO"), which completed construction of a methanol plant in Equatorial Guinea in the second quarter of 2001. During 1999, AMCCO issued $125 million Series A-1 and $125 million Series A-2 senior secured notes due 2004 to fund the remaining construction payments. On January 2, 2002, the Company's partner in AMCCO directed AMCCO to sell 50 percent of its interest in AMPCO as a component of the partner's sale of all of its Equatorial Guinea assets. The proceeds of the AMPCO sale were used to repay in full AMCCO's $125 million Series A-1 Notes on January 28, 2002 and to make a distribution to the Company's partner. Since the Company's partner in AMCCO no longer retains an economic interest in AMPCO, the Company began consolidating AMCCO in 2002, thereby including the $125 million Series A-2 Notes in the Company's balance sheet effective January 28, 2002. The terms of the $125 million Series A-2 Notes remain unchanged. The plant construction started during 1998 and initial production of commercial grade methanol commenced May 2, 2001. The construction cost of the turnkey contract was $322.5 million. Other associated expenditures required to complete the project are estimated to be $12.3 million. There are no further construction contract phase payments due for the methanol plant. The plant produced approximately 57,000 metric tons of methanol in the second quarter of 2002. For the first six months of 2002, the methanol plant produced approximately 266,000 metric tons of methanol. The plant's output is fully subscribed for the balance of 2002.

AMPCO shut down its methanol plant in Equatorial Guinea on March 30, 2002 in order to replace certain materials used in the construction of the steam reformer. The Company is investigating recovery of repair costs and loss of revenue as a result of the shutdown. No recovery has been

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recognized in the accompanying financial statements. The plant was down for approximately 60 days in the second quarter of 2002 and started back up on June 3, 2002. Prior to the shutdown, the plant was producing approximately 2,650 metric tons per day. Currently, the plant has reached production design capacity of 2,500 metric tons per day. AMPCO made arrangements to ensure that its customers did not experience any supply interruptions. The methanol plant shutdown reduced the Company's average gas production from the Alba field during the second quarter of 2002 by approximately 22 million cubic feet of natural gas per day.

(5) COMPANY STOCK REPURCHASE PLAN

The Company's Board of Directors, in February 2000, authorized a repurchase of up to $50 million in the Company's common stock. In the first quarter of 2000, the Company repurchased approximately $30 million of common stock. The 2000 repurchase of 1,386,400 shares at an average cost of $21.84 per share was funded from the Company's current cash flow. On September 17, 2001 the Company's Board of Directors approved an expansion of the original repurchase program from $50 million to $100 million. During the fourth quarter of 2001, in conjunction with the expanded repurchase program, the Board approved a stock repurchase forward program. Under the stock repurchase forward program, one of the Company's banks purchased approximately $35 million of the Company's stock or 1,044,454 shares on the open market during the first quarter of 2002.

The agreement is scheduled to mature in January 2003. Under the provisions of the agreement, the Company can choose to either purchase the shares from the bank, issue additional shares to the bank to the extent that the share price has decreased, pay the bank a net amount of cash to the extent that the share price has decreased, or receive from the bank a net amount of cash to the extent that the share price has increased. The bank has the right to terminate the agreement prior to the maturity date if the Company's share price decreases by 50 percent ($16.77) or if the Company's credit rating is downgraded below BBB- (S&P) or Baa3 (Moody's). If either event occurs and the bank exercises its right to terminate, the Company still retains the right to settle in cash or additional shares. The agreement limits the number of shares to be issued by the Company to 14,000,000 additional shares. Amounts paid or received related to the change in share price will be an addition or reduction to the Company's capital in excess of par value. No settlements have occurred to date. As of June 28, 2002, the fair value of the Company's obligation under the contract would be either an obligation to pay approximately $35.6 million to the bank (and hold the shares as treasury stock), or the bank would return 56,931 shares of Company stock to the Company, or the bank would pay approximately $2.1 million to the Company.

(6) RECENTLY ISSUED PRONOUNCEMENTS

SFAS No. 143, "Accounting for Asset Retirement Obligations," was issued in June 2001. This statement addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This statement requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying cost of the asset. The Company has not quantified the impact of adopting SFAS No. 143, but plans to adopt the statement by January 1, 2003.

SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," was issued in August 2001. This statement addresses financial accounting and reporting for the impairment or disposal of long-lived assets. This statement supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." This statement requires (a) recognition of an impairment loss only if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows and (b) measurement of an impairment loss as the difference between the carrying amount and fair value of the asset. The Company adopted the statement January 1, 2002 with no material impact on the Company's results of operations or financial position.

Emerging Issues Task Force Topic 2-03, "Recognition and Reporting of Gains and Losses on Energy Trading Contracts under EITF Issues No. 98-10," "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," and No. 00-17, "Measuring the Fair Value of Energy-Related Contracts in Applying Issue No. 98-10" was issued in June 2002. The Task Force reached a consensus that all mark-to-market gains and losses on energy trading contracts should be shown net in the income statement whether or not settled physically. Companies would be required to disclose the gross transaction volumes for those energy trading contracts that are physically settled. The consensus is effective for financial statements issued for periods ending after July 15, 2002. Upon application of the consensus, comparative financial statements for prior periods are required to be reclassified to conform to the consensus. The Company has not engaged in material energy trading and risk management activities. Rather the Company has been engaged in marketing of the Company's and third party oil and gas. Should the Company be required to adopt the provisions of EITF 2-03, the result would have reduced gathering, marketing and processing revenues and expenses. The adoption of the consensus would not have an effect on the Company's net results from operations.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

General. We are including the following discussion to inform our existing and potential security holders generally of some of the risks and uncertainties that can affect the Company and to take advantage of the "safe harbor" protection for forward-looking statements afforded under federal securities laws. From time to time, the Company's management or persons acting on our behalf make forward-looking statements to inform existing and potential security holders about the Company. These statements may include projections and estimates concerning the timing and success of specific projects and the Company's future (1) income, (2) oil and gas production, (3) oil and gas reserves and reserve replacement and (4) capital spending. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "plan," "goal" or other words that convey the uncertainty of future events or outcomes. Sometimes we will specifically describe a statement as being a forward-looking statement. In addition, except for the historical information contained in this Form 10-Q, the matters discussed in this Form 10-Q are forward-looking statements. These statements by their nature are subject to certain risks, uncertainties and assumptions and will be influenced by various factors. Should any of the assumptions underlying a forward-looking statement prove incorrect, actual results could vary materially.

We believe the factors discussed below are important factors that could cause actual results to differ materially from those expressed in a forward-looking statement made herein or elsewhere by us or on our behalf. The factors listed below are not necessarily all of the important factors. Unpredictable or unknown factors not discussed herein could also have material adverse effects on actual results of matters that are the subject of forward-looking statements. We do not intend to update our description of important factors each time a potential important factor arises. We advise our stockholders that they should (1) be aware that important factors not described below could affect the accuracy of our forward-looking statements and (2) use caution and common sense when analyzing our forward-looking statements in this document or elsewhere. All of the Company's forward-looking statements, in this document or elsewhere, are qualified by this cautionary disclosure.

Volatility and Level of Hydrocarbon Commodity Prices. Historically, natural gas and crude oil prices have been volatile. These prices rise and fall based on changes in market demand and changes in the political, regulatory and economic climate and other factors that affect commodities markets generally and are outside of our control. Some of our projections and estimates are based on assumptions as to the future prices of natural gas and crude oil. These price assumptions are used for planning purposes. We expect our assumptions will change over time and that actual prices in the future may differ from our estimates. Any substantial or extended decline in the actual prices of natural gas and/or crude oil could have a material adverse effect on (1) the Company's financial position and results of operations (including reduced cash flow and borrowing capacity), (2) the quantities of natural gas and crude oil reserves that we can economically produce, (3) the quantity of estimated proved reserves that may be attributed to our properties and (4) our ability to fund our capital program.

Production Rates and Reserve Replacement. Projecting future rates of oil and gas production is inherently imprecise. Producing oil and gas reservoirs generally have declining production rates. Production rates depend on a number of factors, including geological, geophysical and engineering factors, weather, production curtailments or restrictions, prices for natural gas and crude oil, available transportation capacity, market demand and the political, economic and regulatory climate. Another factor affecting production rates is our ability to replace depleting reservoirs with new reserves through exploration success or acquisitions. Exploration success is difficult to predict, particularly over the short term, where results can vary widely from year to year. Moreover, our ability to replace reserves over an extended period depends not only on the total volumes found, but also on the cost of finding and

developing such reserves. Depending on the general price environment for natural gas and crude oil, our finding and development costs may not justify the use of resources to explore for and develop such reserves. There can be no assurances as to the level or timing of success, if any, that we will be able to achieve in finding and developing or acquiring additional reserves. Acquisitions that result in successful exploration or exploitation projects require assessment of numerous factors, many of which are beyond our control. There can be no assurance that any acquisition of property interests by us will be successful and, if unsuccessful, that such failure will not have an adverse effect on our financial condition, results of operations and cash flows.

Reserve Estimates. Our forward-looking statements may be predicated on our estimates of our oil and gas reserves. All of the reserve data in this Form 10-Q or otherwise made by or on behalf of the Company are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. There are numerous uncertainties inherent in estimating quantities of proved natural gas and oil reserves. Projecting future rates of production and timing of future development expenditures is also inexact. Many factors beyond our control affect these estimates. In addition, the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Therefore, it is common that estimates made by different engineers will vary. The results of drilling, testing and production after the date of an estimate may also require a revision of that estimate, and these revisions may be material. As a result, reserve estimates are generally different from the quantities of oil and gas that are ultimately recovered.

Laws and Regulations. Our forward-looking statements are generally based on the assumption that the legal and regulatory environment will remain stable. Changes in the legal and/or regulatory environment could have a material adverse effect on our future results of operations and financial condition. Our ability to economically produce and sell our oil and gas production is affected and could possibly be restrained by a number of legal and regulatory factors, including federal, state and local laws and regulations in the U.S. and laws and regulations of foreign nations, affecting (1) oil and gas production, including allowable rates of production by well or proration unit, (2) taxes applicable to the Company and/or our production, (3) the amount of oil and gas available for sale, (4) the availability of adequate pipeline and other transportation and processing facilities and (5) the marketing of competitive fuels. Our operations are also subject to extensive federal, state and local laws and regulations in the U.S. and laws and regulations of foreign nations relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. These environmental laws and regulations continue to change and may become more onerous or restrictive in the future. Our forward-looking statements are generally based upon the expectation that we will not be required in the near future to expend amounts to comply with environmental laws and regulations that are material in relation to our total capital expenditures program. However, inasmuch as such laws and regulations are frequently changed, we are unable to accurately predict the ultimate cost of such compliance.

Drilling and Operating Risks. Our drilling operations are subject to various risks common in the industry, including cratering, explosions, fires and uncontrollable flows of oil, gas or well fluids. In addition, a substantial amount of our operations are currently offshore, domestically and internationally, and subject to the additional hazards of marine operations, such as loop currents, capsizing, collision and damage or loss from severe weather. Our drilling operations are also subject to the risk that no commercially productive natural gas or oil reserves will be encountered. The cost of drilling, completing and operating wells is often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including drilling conditions, pressure or irregularities in formations, equipment failures or accidents and adverse weather conditions.

Competition. The Company's forward-looking statements are generally based on a stable competitive environment. Competition in the oil and gas industry is intense both domestically and internationally. We actively compete for reserve acquisitions and exploration leases and licenses, as well as in the gathering and marketing of natural gas and crude oil. Our competitors include the major oil companies, independent oil and gas concerns, individual producers, natural gas and crude oil marketers and major pipeline companies, as well as participants in other industries supplying energy and fuel to industrial, commercial and individual consumers. To the extent our competitors have greater financial resources than currently available to us, we may be disadvantaged in effectively competing for certain reserves, leases and licenses. Recently announced consolidations in the industry may enhance the financial resources of certain of our competitors. From time to time, the level of industry activity may result in a tight supply of labor or equipment required to operate and develop oil and gas properties. The availability of drilling rigs and other equipment, as well as the level of rates charged, may have an effect on our ability to compete and achieve success in our exploration and production activities.

In marketing our production, we compete with other producers and marketers on such factors as deliverability, price, contract terms and quality of product and service. Competition for the sale of energy commodities among competing suppliers is influenced by various factors, including price, availability, technological advancements, reliability and creditworthiness. In making projections with respect to natural gas and crude oil marketing, we assume no material decrease in the availability of natural gas and crude oil for purchase. We believe that the location of our properties, our expertise in exploration, drilling and production operations, the experience of our management and the efforts and expertise of our marketing units generally enable us to compete effectively. In making projections with respect to numerous aspects of our business, we generally assume that there will be no material change in competitive conditions that would adversely affect us.

LIQUIDITY AND CAPITAL RESOURCES

Net cash provided by operating activities decreased $179.1 million to $187.4 million in the six months ended June 30, 2002 from $366.5 million in the same period of 2001. Cash and short-term investments decreased from $73.2 million at December 31, 2001 to $1.7 million at June 30, 2002. These decreases are primarily a result of lower natural gas prices in 2002 versus the comparable period in 2001.

During the first half of 2002, the Company repaid a net $30 million on its $400 million credit facility, which combined with the $380 million borrowed at December 31, 2001, resulted in a balance of $350 million drawn on the $400 million credit facility at June 30, 2002. The Company also has available a $200 million 364-day credit agreement with certain commercial lending institutions. At June 30, 2002, there were no amounts outstanding under this credit agreement. Long-term debt at June 30, 2002 was $947 million compared with $837.2 million at December 31, 2001.

The Company has expended approximately $325 million of its $520 million 2002 capital expenditure budget through June 30, 2002. The Company expects to fund its remaining 2002 capital budget from cash flows from operations and additional borrowings from the credit facility as required. The Company continues to evaluate possible strategic and tactical acquisitions and believes it is positioned to access external sources of funding should it be necessary or desirable in connection with an acquisition.

Through AMPCO, the Company's unconsolidated subsidiary, the Company participated, with a 50 percent expense interest (45 percent ownership net of a five percent carried interest for the Equatorial Guinea Government), in a joint venture with a partner in the construction of a methanol plant on Bioko Island in Equatorial Guinea. The plant is using the gas from the Company's 34 percent owned Alba field as feedstock. The plant is designed to utilize up to 125 MMCF of gas per day and can produce 2,500 metric tons of methanol per day, which equates to approximately 20,000 BBLS per

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day. Initial production of commercial grade methanol commenced May 2, 2001. The plant's output is fully subscribed for the balance of the year 2002.

Prior to January 2002, AMCCO was a 50 percent owned joint venture that owned an indirect 90 percent interest in AMPCO. During 1999, AMCCO issued $125 million Series A-1 and $125 million Series A-2 senior secured notes due 2004 to fund the remaining construction payments. On January 2, 2002, the Company's partner in AMCCO directed AMCCO to sell 50 percent of its interest in AMPCO as a component of the partner's sale of all of its Equatorial Guinea assets. The proceeds of the AMPCO sale were used to repay in full AMCCO's $125 million Series A-1 Notes on January 28, 2002 and to make a distribution to the Company's partner. Since the Company's partner in AMCCO no longer retains an economic interest in AMPCO, the Company began consolidating AMCCO in 2002, thereby including the $125 million Series A-2 Notes in the Company's balance sheet effective January 2002. The terms of the $125 million Series A-2 Notes remain unchanged. The plant construction started during 1998 and initial production of commercial grade methanol commenced May 2, 2001. The construction cost of the turnkey contract was $322.5 million. Other associated expenditures required to complete the project are estimated to be $12.3 million. Payments were due upon the completion of specific phases of the construction. There are no further construction contract phase payments due for the methanol plant. The plant produced approximately 57,000 metric tons of methanol in the second quarter of 2002. For the first six months of 2002, the methanol plant produced approximately 266,000 metric tons of methanol.

AMPCO shut down its methanol plant in Equatorial Guinea on March 30, 2002 in order to replace certain materials used in the construction of the steam reformer. The Company is investigating recovery of repair costs and loss of revenue as a result of the shutdown. No recovery has been recognized in the accompanying financial statements. The plant was down for approximately 60 days in the second quarter of 2002 and started back up on June 3, 2002. Prior to the shutdown, the plant was producing approximately 2,650 metric tons per day. Currently, the plant has reached production design capacity of 2,500 metric tons per day. AMPCO made arrangements to ensure that its customers did not experience any supply interruptions. The methanol plant shutdown reduced the Company's average gas production from the Alba field during the second quarter of 2002 by approximately 22 million cubic feet of natural gas per day.

The Company follows the entitlement method of accounting for its gas imbalances. The Company's estimated gas imbalance receivables were $19.9 million at June 30, 2002 and $20.9 million at December 31, 2001. Estimated gas imbalance liabilities were $14.6 million at June 30, 2002 and $15.5 million at December 31, 2001. These imbalances are valued at the amount which is expected to be received or paid to settle the imbalances. The settlement of the imbalances can occur either over the life or at the end of the life of a well, on a volume basis or by cash settlement. The Company does not expect that a significant portion of the settlements will occur in any one year. Thus, the Company believes the settlement of gas imbalances will not have a material impact on its liquidity.

RESULTS OF OPERATIONS

For the second quarter of 2002, the Company recorded net income of $17.1 million, or $.30 per share, compared with net income of $51.3 million, or $.91 per share, in the second quarter of 2001. The decrease resulted primarily from lower production volumes and lower product prices on natural gas, which decreased 14 percent and 25 percent, respectively, compared with the second quarter of 2001. During the first six months of 2002, the Company recorded net income of $2 million, or $.04 per share, compared with $157.2 million, or $2.79 per share, in the first six months of 2001. The decreased earnings through the first half of 2002 were a result of significantly lower commodity prices, particularly for natural gas coupled with decreased natural gas production volumes. Natural gas prices decreased 51 percent and production decreased eight percent, respectively, compared with the first half of 2001.

Gas sales for the Company, excluding third party sales by Noble Gas Marketing, Inc. ("NGM"), a wholly owned subsidiary of the Company, decreased 35 percent and 54 percent for the three months and six months ended June 30, 2002 compared with the same periods in 2001. Sales were down primarily due to decreases in average price of 25 percent and 51 percent, respectively, for the three month and six month periods ending June 30, 2002, compared with the same periods in 2001. Production volumes were also lower for the three month and six month periods ending June 30, 2002, with decreases of 14 percent and eight percent, respectively, for the comparable periods in 2001.

Oil sales for the Company, excluding third party sales by Noble Trading, Inc. ("NTI"), a wholly owned subsidiary of the Company, increased 16 percent and eight percent for the three months and six months ended June 30, 2002 compared to the same periods in 2001. Sales were up primarily due to increases in average daily production of 17 percent and 20 percent for the three months and six months ended June 30, 2002 compared to the same periods in 2001.

NGM markets the majority of the Company's natural gas, as well as certain third party gas. NGM sells gas directly to end-users, gas marketers, industrial users, interstate and intrastate pipelines and local distribution companies. NTI markets a portion of the Company's oil, as well as certain third-party oil. The Company records all of NGM's and NTI's sales and expenses as gathering, marketing and processing revenues and expenses. All intercompany sales and expenses have been eliminated.

For the second quarter of 2002, revenues and expenses from NGM and NTI third party sales totaled $152.5 million and $150.5 million, respectively, for a combined gross margin of $2.0 million. In comparison, for the second quarter of 2001, NGM and NTI third party sales and expenses of $184.3 million and $181.6 million, respectively, resulted in a combined gross margin of $2.7 million. For the six months ended June 30, 2002, combined NGM and NTI revenues and expenses from third party sales totaled $321.5 million and $317.8 million, respectively, for a gross margin of $3.7 million. In comparison, combined NGM and NTI third party sales and expenses of $428 million and $421.7 million, respectively, resulted in a gross margin of $6.3 million for the same period in 2001.

The Company, through its subsidiaries, from time to time, uses various price risk management arrangements in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations. Such arrangements include fixed price forward sales, costless collars and other contractual arrangements. Although these arrangements expose the Company to credit risk, the Company takes reasonable steps to protect itself from nonperformance by its counterparties; however, the Company is not able to predict sudden changes in its counterparties' creditworthiness. Gains and losses from such arrangements related to the Company's oil and gas production and which qualify for hedge accounting treatment are recorded in oil and gas sales and royalties upon sale of the associated products. For more information, see "Item 3. Quantitative and Qualitative Disclosures About Market Risk" of this Form 10-Q.

At June 30, 2002, the Company recorded oil and gas hedge receivables of $9.3 million, oil and gas hedge liabilities of $12.6 million and other comprehensive loss, net of tax, of $2.0 million related to the Company's hedging contracts.

Certain selected oil and gas operating statistics follow:

	For the three months ended June 30,		For the six months ended June 30,	
	2002	2001	2002	2001
Oil revenue (in thousands)	$ 75,224	$ 64,692	$ 135,710	$ 126,164
Average daily oil production—BBLS	34,641	29,492	34,512	28,812
Average oil price per BBL	$ 24.24	$ 24.60	$ 22.05	$ 24.76
Gas revenues (in thousands)	$ 102,632	$ 158,446	$ 185,469	$ 406,597
Average daily gas production—MCF	374,631	436,514	391,328	425,127
Average gas price per MCF	$ 3.08	$ 4.12	$ 2.68	$ 5.42

BBLS—barrels
MCF—thousand cubic feet

Oil and gas exploration expense decreased $6.5 million and $8.7 million for the three months and six months ended June 30, 2002, as compared with the same periods in 2001. The second quarter 2002 decrease is primarily due to a decrease in dry hole expense and the six month decrease is attributable to a $15 million decrease in dry hole expense offset by a $6 million increase in seismic and other expenses.

Oil and gas operations expense increased $0.8 million and $4.1 million for the three months and six months ended June 30, 2002, as compared with the same periods in 2001. The increase in the second quarter of 2002 was due to increases in lease operating expense and production taxes while the increase for the six month period ended June 30, 2002 was primarily attributable to a $4.3 million increase in lease operating expense.

Depreciation, depletion and amortization (DD&A) expense decreased $3.8 million and increased $7.4 million, respectively, for the three months and six months ended June 30, 2002 compared with the same periods in 2001. The unit rate of DD&A per barrel of oil equivalents (BOE), converting gas to oil on the basis of six MCF per barrel, was $8.23 for the first six months of 2002 compared with $7.82 for the same period of 2001. The increase in the unit rate per BOE is due primarily to increased development costs incurred in the Gulf of Mexico to stabilize the Company's oil and gas production volumes, which are being amortized in the current and subsequent quarters. The Company has recorded, through charges to DD&A, a reserve for future liabilities related to dismantlement and reclamation costs for offshore facilities. This reserve is based on the best estimates of Company engineers of such costs to be incurred in future years.

SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," was issued in August 2001. This statement addresses financial accounting and reporting for the impairment or disposal of long-lived assets. This statement supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." This statement requires (a) recognition of an impairment loss only if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows and (b) measurement of an impairment loss as the difference between the carrying amount and fair value of the asset. The Company adopted the statement January 1, 2002 with no material impact on the Company's results of operations or financial position.

Interest expense increased 80 percent and 63 percent for the three months and six months ended June 30, 2002 as compared with the same periods in 2001. The increase in interest expense is attributable to an increase in short-term loans and credit facility borrowings in the second quarter of 2002 as well as the interest expense associated with the AMCCO debt.

FUTURE TRENDS

The Company expects oil and gas production to increase in 2002 and 2003 compared to 2001. The increase in 2002 will be due primarily to a full year of production from the expansion of the Alba field in Equatorial Guinea and the Hanze field in the North Sea. The increase in 2003 will be due primarily to a full year of production in China and Ecuador.

The Company set its 2002 capital expenditure budget at approximately $520 million. Such expenditures are planned to be funded through internally generated cash flows. The Company believes that it has the capital structure to take advantage of strategic acquisitions, as they become available, through internally generated cash flows or borrowings.

Management believes that the Company is well positioned with its balanced reserves of oil and gas to take advantage of future price increases that may occur. However, the uncertainty of oil and gas prices continues to affect the oil and gas industry. The Company cannot predict the extent to which its revenues will be affected by inflation, government regulation or changing prices.

The Company's Board of Directors, in February 2000, authorized a repurchase of up to $50 million in the Company's common stock. In the first quarter of 2000, the Company repurchased approximately $30 million of common stock. The 2000 repurchase of 1,386,400 shares at an average cost of $21.84 per share was funded from the Company's current cash flow. On September 17, 2001 the Company's Board of Directors approved an expansion of the original repurchase program from $50 million to $100 million. During the fourth quarter of 2001, in conjunction with the expanded repurchase program, the Board approved a stock repurchase forward program. Under the stock repurchase forward program, one of the Company's banks purchased approximately $35 million of the Company's stock or 1,044,454 shares on the open market during the first quarter of 2002.

The agreement is scheduled to mature in January 2003. Under the provisions of the agreement, the Company can choose to either purchase the shares from the bank, issue additional shares to the bank to the extent that the share price has decreased, pay the bank a net amount of cash to the extent that the share price has decreased, or receive from the bank a net amount of cash to the extent that the share price has increased. The bank has the right to terminate the agreement prior to the maturity date if the Company's share price decreases by 50 percent ($16.77) or if the Company's credit rating is downgraded below BBB- (S&P) or Baa3 (Moody's). If either event occurs and the bank exercises its right to terminate, the Company still retains the right to settle in cash or additional shares. The agreement limits the number of shares to be issued by the Company to 14,000,000 additional shares. Amounts paid or received related to the change in share price will be an addition or reduction to the Company's capital in excess of par value. No settlements have occurred to date. As of June 28, 2002, the fair value of the Company's obligation under the contract would be either an obligation to pay approximately $35.6 million to the bank (and hold the shares as treasury stock), or the bank would return 56,931 shares of Company stock to the Company, or the bank would pay approximately $2.1 million to the Company.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to market risk in the normal course of its business operations. Management believes that the Company is well positioned with its mix of oil and gas reserves to take advantage of future price increases that may occur. However, the uncertainty of oil and gas prices continues to impact the domestic oil and gas industry. Due to the volatility of oil and gas prices, the Company, from time to time, has used derivative hedging and may do so in the future as a means of limiting its exposure to price changes.

During the second quarter of 2002, the Company had entered into various natural gas costless collars, natural gas costless collar combinations and crude oil costless collar transactions related to its production.

In second quarter 2002, the natural gas costless collars were for 80,000 MMBTU of natural gas per day, with floor prices ranging from $2.75 to $3.25 per MMBTU and ceiling prices ranging from $3.50 to $5.10 per MMBTU; the costless collar combinations were for 100,000 MMBTU of natural gas per day, with floor prices ranging from $2.00 to $2.25 per MMBTU and ceiling prices ranging from $2.95 to $3.10 per MMBTU, with a $.25 to $.30 premium to index on prices below the floors. The realized effect of the natural gas arrangements on gas sales for the second quarter was a decrease of $.06 per MCF. For the first six months of 2002, the Company had natural gas costless collars for 160,387 MMBTU per day, with floor prices ranging from $2.00 to $3.25 per MMBTU and ceiling prices ranging from $2.45 to $5.10 per MMBTU. The realized effect of the costless collar transactions for the first six months of 2002 in the average natural gas price was an increase of $.03 per MCF.

The crude oil costless collars for the second quarter were for 110 BBLS of oil per day, with a floor price of $24.00 per BBL and a ceiling price of $29.40 per BBL. There was no realized effect on oil sales for second quarter 2002 for these costless collars.

In addition, the Company has entered into natural gas arrangements to support the Company's investment program for the periods: July to September 2002, costless collars for 120,000 MMBTU of natural gas per day, with floor prices ranging from $2.75 to $3.25 per MMBTU and ceiling prices ranging from $3.50 to $5.10 per MMBTU; July to September 2002, costless collar combinations for 75,000 MMBTU of natural gas per day, with floor prices ranging from $3.00 to $3.25 per MMBTU and ceiling prices ranging from $4.30 to $5.00 per MMBTU, with a $.50 premium to index price on prices below the floor prices; October to December 2002, costless collars for 115,000 MMBTU of natural gas per day, with floor prices ranging from $3.00 to $3.50 per MMBTU and ceiling prices ranging from $3.75 to $5.05 per MMBTU. Of the 120,000 MMBTU of natural gas per day costless collars for July to September 2002 and of the 115,000 MMBTU of natural gas per day costless collars for October to December 2002, 60,000 MMBTU for the third quarter and 25,000 MMBTU for the fourth quarter 2002 of natural gas per day were terminated and, as a result, the Company will recognize an additional $.70 to $.34 per MMBTU on the 60,000 to 25,000 MMBTU of natural gas per day in the third and fourth quarter of 2002, respectively.

The Company has entered into various crude oil costless collar transactions for July to September 2002 for 10,000 BBLS of oil per day, with floor prices ranging from $23.00 to $24.00 per BBL and ceiling prices ranging from $29.30 to $30.00 per BBL.

The Company has costless collar transactions related to calendar year 2003 for 45,000 MMBTU of natural gas production per day with a floor price of $3.25 per MMBTU and a ceiling price of $4.00 per MMBTU.

The Company assumed swaps related to the acquisition of Aspect Resources, Inc. that cover the period January 2002 to March 2004 for 5,116 MMBTU of natural gas production and 124 BBLS of oil production per day. Based on the cost of these swaps, the Company will realize prices of approximately

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$3.20 per MMBTU and $22.00 per BBL for this time period related to these volumes. There was no realized effect on the average gas price and a realized effect of a $.03 per BBL decrease in the average crude oil price in the second quarter of 2002 due to the purchased swaps. The realized effect of the purchased swaps for the first six months of 2002 was an increase of $.02 per MCF and a decrease of $.01 per BBL in the average natural gas and crude oil prices.

During the second quarter of 2001, the Company had no price risk management arrangements for its production other than those entered into by NGM, which are described below.

NGM, from time to time, employs price risk management arrangements in connection with its purchases and sales of production. While most of NGM's purchases are made for an index-based price, NGM's customers often require prices that are either fixed or related to NYMEX. In order to establish a fixed margin and mitigate the risk of price volatility, NGM may convert a fixed or NYMEX sale to an index-based sales price (such as purchasing a NYMEX futures contract at the Henry Hub with an adjoining basis swap at a physical location). Due to the size of such transactions and certain restraints imposed by contract and by Company guidelines, as of June 30, 2002 the Company believes it had no material market risk exposure from NGM's price risk arrangements. During the second quarter of 2002, NGM had price risk arrangements with broker-dealers that represented approximately 1,047,000 MMBTU's of gas per day. Arrangements for July 2002 through May 2006, which range from 20,000 MMBTU's to 959,000 MMBTU's of gas per day, for future physical transactions, were not closed at June 30, 2002. During the second quarter of 2001, NGM had price risk arrangements with broker-dealers that represented approximately 1,098,000 MMBTU's of gas per day. For the six months ended June 30, 2002, NGM had hedging transactions that represented approximately 1,473,000 MMBTU's of gas per day, compared with 1,198,000 MMBTU's of gas per day for the same period in 2001.

The Company has a $400 million credit agreement, which exposes the Company to the risk of earnings or cash flow loss due to changes in market interest rates. At June 30, 2002, the Company had $350 million outstanding on its $400 million credit facility, which has a maturity date of November 30, 2006. The interest rate is based upon a Eurodollar rate plus a range of 60 to 145 basis points depending upon the percentage of utilization and credit rating. The Company also has a $200 million 364-day credit agreement, which exposes the Company to the risk of earnings or cash flow loss due to changes in market interest rates. The interest rate is based upon a Eurodollar rate plus a range of 62.5 to 150 basis points depending upon the percentage of utilization and credit rating. At June 30, 2002, there were no amounts outstanding under this credit agreement. All other Company long-term debt is fixed-rate and, therefore, does not expose the Company to the risk of earnings or cash flow loss due to changes in market interest rates.

The Company does not invest in foreign currency derivatives. The U.S. dollar is considered the primary currency for each of the Company's international operations. Transactions that are completed in a foreign currency are translated into U.S. dollars and recorded in the financial statements. Translation gains or losses were not material in any of the periods presented and the Company does not believe it is currently exposed to any material risk of loss on this basis. Such gains or losses are included in other expense on the income statement. However, certain sales transactions are concluded in foreign currencies and the Company therefore is exposed to potential risk of loss based on fluctuation in exchange rates from time to time.

PART II. OTHER INFORMATION
ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) The Company has no exhibits to furnish pursuant to this Item 6(a).

(b) The following reports on Form 8-K were filed by the Company:

(i) A Form 8-K was filed on May 17, 2002, relating to the dismissal of Arthur Andersen LLP as the Company's independent accountant and the Company's retention of KPMG LLP as its new independent accountant. The date of such report (the date of the earliest event reported) was May 14, 2002.

SIGNATURE

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

NOBLE ENERGY, INC.
(Registrant)

Date August 13, 2002 By: /s/ JAMES L. MCELVANY

JAMES L. McELVANY
Senior Vice President, Finance and Treasurer
(Principal Financial Officer
and Authorized Signatory)

INDEX TO EXHIBITS

Exhibit Number	Exhibit
	None

QuickLinks