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

FORM 10-Q

/X/ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2001

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: 0-7062

NOBLE AFFILIATES, INC.
(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

Delaware	73-0785597
(STATE OF INCORPORATION)	(I.R.S. EMPLOYER IDENTIFICATION NUMBER)

350 Glenborough Drive, Suite 100 Houston, Texas	77067
(ADDRESS OF PRINCIPAL EXECUTIVE OFFICES)	(ZIP CODE)

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

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 X No

Number of shares of common stock outstanding as of November 2, 2001: 56,598,685

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	(Unaudited) September 30, 2001	December 31, 2000
ASSETS		
Current Assets:		
Cash and short-term investments	$ 18,008	$ 23,152
Accounts receivable-trade	171,128	235,843
Materials and supplies inventories	21,291	4,645
Other current assets	73,538	7,621
Total Current Assets	283,965	271,261
Property, Plant and Equipment, at cost	3,685,972	3,256,467
Less: accumulated depreciation, depletion and amortization	(1,957,409)	(1,771,344)
	1,728,563	1,485,123
Investment in Unconsolidated Subsidiary	118,378	74,159
Other Assets	71,371	48,737
Total Assets	$ 2,202,277	$ 1,879,280
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable-trade	$ 230,604	$ 279,379
Other current liabilities	81,390	30,730
Income taxes-current	15,308	-

----------- ------------ Total Current Liabilities... 311,994 325,417 ------------ ------------ Deferred Income Taxes.. 158,028 117,048 ------------ ------------ Other Deferred Credits and Noncurrent Liabilities.................... 64,672 61,639 ------------ ------------ Long-term Debt.. 635,626 525,494 ------------ ------------ Shareholders' Equity: Common stock.. 198,352 196,672 Capital in excess of par value.................................... 388,112 373,259 Retained earnings... 479,726 325,452 Accumulated other comprehensive income............................ 11,468 ------------ ------------ 1,077,658 895,383 Less Common Stock in Treasury (at cost, 2,911,300 shares).. (45,701) (45,701) ------------ ------------ Total Shareholders' Equity...................................... 1,031,957 849,682 ------------ ------------ Total Liabilities and Shareholders' Equity........................ $ 2,202,277 $ 1,879,280 ============ ============

SEE NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS.

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

Three Months Ended September 30, -- 2001 2000 ------------ ---------- REVENUES: Oil and gas sales and royalties.................................... $ 168,547 $ 211,478 Gathering, marketing and processing............................... 134,417 145,876 Income (loss) from unconsolidated subsidiary....................... 1,229 336 Other income... 643 3,242 ------------ ------------ 304,836 360,932 ------------ ------------- COSTS AND EXPENSES: Oil and gas operations... 32,005 33,976 Oil and gas exploration.. 48,862 17,469 Gathering, marketing and processing.............................. 130,782 142,831 Depreciation, depletion and amortization.......................... 68,536 57,051 Selling, general and administrative............................... 9,726 10,786 Interest... 10,974 9,295 Interest capitalized... (3,575) (1,456) ------------ ------------ 297,310 269,952 ------------ ------------- INCOME BEFORE TAXES... 7,526 90,980 INCOME TAX PROVISION... 3,718 (1) 33,763 (1) ------------ ------------ NET INCOME.. $ 3,808 $ 57,217 ============ ============ BASIC EARNINGS PER SHARE... $ 0.07 (2) $ 1.02 (2) ============ ============ DILUTED EARNINGS PER SHARE... $ 0.07 (2) $ 1.01 (2) ============ ============

SEE NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS.

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

Nine Months Ended September 30, --- 2001 2000 ------------ ---------- REVENUES: Oil and gas sales and royalties.................................... $ 714,537 $ 531,590 Gathering, marketing and processing............................... 562,387 396,413 Income

(loss) from unconsolidated subsidiary....................... 482
1,227 Other
income...
1,912 10,073 ------------ ------------- 1,279,318 939,303 --------
---- ------------- COSTS AND EXPENSES: Oil and gas
operations... 98,573
88,122 Oil and gas
exploration.. 114,153
44,718 Gathering, marketing and
processing............................... 552,457 386,598
Depreciation, depletion and
amortization.......................... 209,647 165,473 Selling,
general and administrative............................... 32,207
34,772
Interest...
30,704 28,255 Interest
capitalized...
(10,372) (3,942) ------------ ------------- 1,027,369 743,996 ----
-------- ------------- INCOME BEFORE
TAXES.. 251,949
195,307 INCOME TAX
PROVISION..
90,898 (1) 74,350 (1) ------------ ------------- NET
INCOME...
$ 161,051 $ 120,957 ============ ============= BASIC EARNINGS PER
SHARE... $ 2.85 (2) $
2.16 (2) ============ ============= DILUTED EARNINGS PER
SHARE.. $ 2.81 (2) $
2.13 (2) ============ =============

SEE NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS.

NOBLE AFFILIATES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
AND SHAREHOLDERS' EQUITY
(Dollars in Thousands)
(Unaudited)

Accumulated Capital in Other Total Comprehensive Common Excess of Retained Comprehensive Treasury Shareholders' Income Stock Par Value Earnings Income Stock Equity - -- Balance at December 31, 2000 196,672 373,259 325,452 (45,701) 849,682 Net income 161,051 161,051 161,051 Derivatives marked to market 11,468 11,468 11,468 Shares issued 1,680 14,853 16,533 Dividends declared ($.12 per share) (6,777) (6,777) ----------- -- Total 172,519 =========== Balance at September 30, 2001 198,352 388,112 479,726 11,468 (45,701) 1,031,957
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SEE NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS.

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

Nine Months Ended September 30, ---------------------------------
------- 2001 2000 ------------ ---------- Cash Flows from
Operating Activities: Net
income..

$ 161,051 $ 120,957 Adjustments to reconcile net income to net cash provided by operating activities: Depreciation, depletion and amortization........................... 209,647 165,473 Dry hole... 79,661 18,078 Amortization of undeveloped lease costs, net....................... 12,297 8,514 (Gain) loss on disposal of assets................................. (1,919) (2,823) Noncurrent deferred income taxes.................................. 40,981 13,106 (Income) loss from unconsolidated subsidiary....................... (482) (1,227) Increase (decrease) in deferred credits........................... 3,033 4,932 (Increase) decrease in other..................................... (9,188) (1,856) Changes in working capital, not including cash: (Increase) decrease in accounts receivable......................... 64,715 (74,431) (Increase) decrease in other current assets and inventories......... (84,411) 27,341 Increase (decrease) in accounts payable............................ (48,775) 59,831 Increase (decrease) in other current liabilities................... 35,352 (26,110) ------------- ---------- Net Cash Provided by Operating Activities 461,962 311,785 ------------- ---------- Cash Flows From Investing Activities: Capital expenditures.. (544,421) (276,920) Investment in unconsolidated subsidiary............................. (43,736) (37,385) Proceeds from sale of property, plant and equipment.................. 1,295 11,906 ------------- ---------- Net Cash Used in Investing Activities .... (586,862) (302,399) ------------- ---------- Cash Flows From Financing Activities: Common stock repurchases... (30,283) Exercise of stock options... 16,533 7,433 Cash dividends... (6,777) (6,745) Proceeds from credit facility.. 235,000 72,000 Repayment of credit facility.. (125,000) (27,000) ------------ ---------- Net Cash Provided by Financing Activities................................ 119,756 15,405 ------------ ---------- Increase (Decrease) in Cash and Short-term Investments.................. (5,144) 24,791 ------------ ---------- Cash and Short-term Investments at Beginning of Period.................. 23,152 2,925 ------------ ---------- Cash and Short-term Investments at End of Period........................ $ 18,008 $ 27,716 ============ ========== Supplemental Disclosures of Cash Flow Information: Cash paid during the period for: Interest (net of amount capitalized)................................ $ 16,389 $ 20,154 Income taxes... $ 66,131 $ 41,765

SEE NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS.

NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS
(Unaudited)

In the opinion of Noble Affiliates, 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 September 30, 2001 and December 31, 2000; the results of operations for the three month and nine month periods ended September 30, 2001 and 2000, respectively; the statement of comprehensive income and equity for the nine month period ended September 30, 2001; and the cash flows for the nine month periods ended September 30, 2001 and 2000. 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, 2000.

(1) INCOME TAX PROVISION (BENEFIT)

For the three months ended September 30:

(In thousands) ---------------------------------- 2001 2000 ---------- --------- Current.. $(12,788) $ 33,622 Deferred.. 16,506 141 ---------- --------- $ 3,718 $ 33,763 ========== =========

For the nine months ended September 30:

(In thousands) ------------------------------------ 2001 2000 -------
--- ---------
Current...
$ 49,917 $ 61,727
Deferred..
40,981 12,623 ---------- --------- $ 90,898 $ 74,350 ==========
=========

(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 tables summarize the calculation of basic earnings per share ("EPS") and diluted EPS.

For the three months ended September 30:

2001 2000 --

- INCOME
SHARES
INCOME
SHARES (IN
THOUSANDS,
EXCEPT PER
SHARE)
(NUMERATOR)
(DENOMINATOR)
(NUMERATOR)
(DENOMINATOR)
- ----------

Net
income/shares
$3,808
56,595
$57,217
55,875 - ---

------ BASIC
EPS $0.07
$1.02 - ----

----- Net
income/shares
$3,808
56,595
$57,217
55,875
EFFECT OF
DILUTIVE
SECURITIES

Stock
options 575
830 Adjusted
net
income/shares
$3,808
57,170
$57,217
56,705 - ---

DILUTED EPS
$0.07 $1.01
- ----------

For the nine months ended September 30:

2001 2000 --

- INCOME
SHARES
INCOME
SHARES (IN
THOUSANDS,
EXCEPT PER
SHARE)
(NUMERATOR)
(DENOMINATOR)
(NUMERATOR)
(DENOMINATOR)
- ----------

Net
income/shares
$161,051
56,502
$120,957
56,008 - ---

------ BASIC
EPS $2.85
$2.16 - ----

----- Net
income/shares
$161,051
56,502
$120,957
56,008
EFFECT OF
DILUTIVE
SECURITIES
Stock
options 829
690 Adjusted
net
income/shares
$161,051
57,331
$120,957
56,698 - ---

DILUTED EPS
$2.81 $2.13
- ----------

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(3) TRADING AND HEDGING ACTIVITIES

The Company, through its subsidiaries, from time to time, uses various hedging arrangements in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations. Such arrangements include fixed price hedges, costless collars, and other contractual arrangements. Although these hedging arrangements expose the Company to credit risk, the Company monitors the creditworthiness of its counterparties, which generally are major financial institutions, and believes that losses from nonperformance are unlikely to occur. Hedging gains and losses related to the Company's oil and gas production are recorded in oil and gas sales and royalties upon settlement.

During the third quarter of 2001, the Company had no oil or gas hedging transactions for its current production other than those entered into by NGM, which are described below.

On August 16, 2001, the Company (floating price payor) entered into a total of three natural gas costless collar contracts related to its production. The first contract, for the fourth quarter of 2001, for 50,000 MMBTU of gas per day, has a floor price of $3.25 per MMBTU and a ceiling price of $4.60 per MMBTU. The other two contracts, for calendar year 2002, each for 25,000 MMBTU of gas per day, have a floor price of $3.25 per MMBTU and ceiling prices ranging from $5.05 to $5.10 per MMBTU. These contracts entitle the Company to receive settlement from the counterparty (fixed price payor) on a calendar quarterly basis, in amounts, if any, by which the average settlement price for the last scheduled NYMEX trading day applicable for each month, per calendar quarter, is less than the floor price. The Company would pay the counterparty if the average settlement price for the last scheduled NYMEX trading day applicable for each month per calendar quarter is more than the ceiling price. The amount payable by the floating price payor, if the floating price is above the ceiling price, is the product of the notional quantity per calculation period and the excess, if any, of the floating price over the ceiling price in respect of each calendar quarter. The amount payable by the fixed price payor, if the floating price is below the floor price, is the product of the notional quantity per calculation period and the excess, if any, of the floor price over the floating price in respect of each calendar quarter.

For calendar year 2000, the Company had entered into three crude oil premium swap contracts related to its production. Two of the contracts provided for payments based on daily NYMEX settlement prices. These contracts related to 2,500 BBLS per day and 2,000 BBLS per day and had trigger prices of $21.73 per BBL and $22.45 per BBL, respectively, and both had knockout prices of $17.00 per BBL. These two contracts entitled the Company to receive settlements from the counterparties in amounts, if any, by which the settlement price for each NYMEX trading day was less than the trigger price, provided the NYMEX price was also greater than the $17.00 per BBL knockout price. If a daily settlement price was $17.00 per BBL or less, then neither party had any liability to the other for that day. If a daily settlement price was above the applicable trigger price, then the Company would have owed the counterparty for the excess of the settlement price over the trigger price for that day. Payment was made monthly under each of these contracts, in an amount equal to the net amount due to either party based on the sum of the daily amounts determined as described in this paragraph for that month.

The third contract related to 2,500 BBLS per day and provided for payments based on monthly average NYMEX settlement prices. The contract entitled the Company to receive monthly settlements from the counterparty in an amount, if any, by which the arithmetic average of the daily NYMEX settlement prices for the month was less than the trigger price, which was $21.73 per BBL, multiplied by the number of days in the month, provided such average NYMEX price was also greater than the $17.00 per BBL knockout price. If the average NYMEX settlement price for the month was $17.00 per BBL or less, then neither party would have any liability to the other for that month. If the average NYMEX settlement price for the month was above the trigger price, then the Company would have paid the

counterparty an amount equal to the excess of the average settlement price over the trigger price, multiplied by the number of days in the month.

The Company treated the swap component of these contracts as a hedge (for accounting purposes only), at swap prices ranging from $19.40 per BBL to $20.20 per BBL, which existed at the dates it entered into these contracts. In addition, the Company separately accounted for the premium component of these contracts by marking them to market, resulting in a gain of $1,663,000 and $2,920,000 recorded in other income for the three months and nine months ended September 30, 2000, respectively.

In addition to the hedging arrangements pertaining to the Company's production as described above, Noble Gas Marketing, Inc. ("NGM") employs various hedging 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.

The Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standard ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities" in June 1998. The Statement establishes accounting and reporting standards requiring every derivative instrument (including certain derivative instruments embedded in other contracts) to be recorded in the balance sheet as either an asset or liability measured at its fair value. The Statement requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met wherein gains and losses are reflected in stockholder equity until the hedged item is recognized. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

Due to the issuance of SFAS No. 137, which deferred the effective date of SFAS No. 133, the Company was required to adopt the statement for fiscal years beginning after June 15, 2000. SFAS No. 133 was required to be applied to (a) derivative instruments and (b) certain derivative instruments embedded in hybrid contracts that were issued, acquired, or substantively modified after December 31, 1997 (and, at the Company's election, before January 1, 1998). During 2000, the FASB issued SFAS No. 138 which amended the accounting and reporting standards of SFAS No. 133 for certain derivative instruments and certain hedging activities and was required to be adopted concurrently with SFAS No. 133. The normal purchase and normal sales exception may be applied to contracts that implicitly or explicitly permit net settlement and contracts that have a market mechanism to facilitate net settlement. The Company adopted SFAS Nos. 133 and 138 effective January 1, 2001. Due to the adoption of SFAS Nos. 133 and 138, NGM recorded on the Balance Sheet and Statement of Other Comprehensive Income and Equity, $52.7 million in other current assets; $41.4 million in other current liabilities; $642.5 thousand in long term assets; and $509.0 thousand in other income from hedging transactions for the first nine months of 2001.

(4) METHANOL PLANT

The Company's unconsolidated subsidiary, Atlantic Methanol Capital Company ("AMCCO"), is a 50 percent owned joint venture that owns 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 $250 million senior secured notes due 2004, which are not included in the Company's balance sheet, to fund the remaining construction payments. 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 and produce marketable supplies of methanol, some of which have been delayed, are projected to be $125.5 million. The Company paid approximately $1.7 million in construction contract phase payments in the third quarter of 2001. The plant produced approximately 201,800 metric tons of methanol in the third quarter of 2001. The plant's output is fully subscribed for the balance of the year 2001.

The methanol plant in Equatorial Guinea is expected to be shut down for approximately 30 days in the fourth quarter of 2001 to permit the contractor to complete final construction requirements under the contract. The partners have elected to do the work now, during a period of low methanol pricing, to minimize the economic impact of this

required work. The shutdown will result in a reduction of approximately 930,000 MCF of gas sales, net to the Company's interest, to the plant from the Alba field.

(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. 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. Out of the expanded $100 million repurchase program, approximately $70 million remains authorized to purchase additional shares. Under the original $50 million authorization, the Company repurchased approximately $30 million of common stock in the first quarter of 2000. The Company has not yet repurchased any additional shares under the expanded authorization.

(6) RECLASSIFICATION TO CONFORM TO CURRENT YEAR PRESENTATION

Certain reclassifications have been made to the 2000 consolidated financial statements to conform to the 2001 presentation.

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 increased to $462 million in the nine months ended September 30, 2001 from $311.8 million in the same period of 2000. Cash and short-term investments decreased from $23.2 million at December 31, 2000 to $18 million at September 30, 2001.

During the first nine months of 2001, the Company borrowed a net $110 million on its $300 million credit facility, which combined with the $80 million borrowed at December 31, 2000, resulted in a balance of $190 million drawn on the $300 million credit facility at September 30, 2001. Long-term debt at September 30, 2001 was $635.6 million compared with $525.5 million at December 31, 2000.

The Company has expended approximately $588.1 million of its $727 million 2001 capital expenditure budget through September 30, 2001. The Company expects to fund its remaining 2001 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 Atlantic Methanol Production Company ("AMPCO"), 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 CMS Energy Corporation 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 was designed to utilize up to 125 MMCF of gas per day. The gas is priced at $.25 per MMBTU.

On January 29, 1998, AMPCO awarded a contract to Raytheon Engineers and Constructors to build the methanol plant. The plant was designed to produce 2,500 metric tons of methanol per day, which equates to approximately 20,000 BBLS per day. Initial production of commercial grade methanol commenced May 2, 2001. The plant's output is fully subscribed for the balance of the year 2001.

The Company's unconsolidated subsidiary, Atlantic Methanol Capital Company ("AMCCO"), is a 50 percent owned joint venture that owns an indirect 90 percent interest in AMPCO. During 1999, AMCCO issued $250 million senior secured notes due 2004, which are not included in the Company's balance sheet, to fund the remaining construction payments. 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 and produce marketable supplies of methanol, some of which have been delayed, are projected to be $125.5 million. Payments were due upon the completion of specific phases of the

construction. The Company paid approximately $1.7 million in construction contract phase payments in the third quarter of 2001. The plant produced approximately 201,800 metric tons of methanol in the third quarter of 2001.

The methanol plant in Equatorial Guinea is expected to be shut down for approximately 30 days in the fourth quarter of 2001 to permit the contractor to complete final construction requirements under the contract. The partners have elected to do the work now, during a period of low methanol pricing, to minimize the economic impact of this required work. The shutdown will result in a reduction of approximately 930,000 MCF of gas sales, net to the Company's interest, to the plant from the Alba field.

The Company follows the entitlement method of accounting for its gas imbalances. The Company's estimated gas imbalance receivables were $19.6 million at September 30, 2001 and $18.5 million at December 31, 2000. Estimated gas imbalance liabilities were $15.8 million at September 30, 2001 and $14.2 million at December 31, 2000. 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 third quarter of 2001, the Company recorded net income of $3.8 million, or $.07 per share, compared with a net income of $57.2 million, or $1.02 per share, in the third quarter of 2000. The decreased earnings in the third quarter of 2001 were a result of lower commodity prices, particularly for natural gas, and higher exploration expense, although these effects were partially offset by continued growth in production volumes. Natural gas and oil prices decreased 36 percent and 13 percent, respectively, compared with the third quarter of 2000, offset by higher natural gas and oil production volumes, which increased 7.5 percent and 22 percent, respectively, compared with the third quarter of 2000. Exploration expense increased 180 percent compared to the third quarter of 2000. During the first nine months of 2001, the Company recorded net income of $161.1 million, or $2.85 per share, compared with $121.0 million, or $2.16 per share, in the first nine months of 2000. The year to date increase resulted from higher natural gas prices, which increased 36 percent, coupled with a six percent and 16 percent increase, respectively, in average daily natural gas and oil production volumes, offset by a 155 percent increase in exploration expense, compared to the same period in 2000.

Gas sales for the Company, excluding third party sales by Noble Gas Marketing, Inc. ("NGM"), a wholly owned subsidiary of the Company, decreased 32 percent and increased 43 percent for the three months and nine months ended September 30, 2001 compared with the same periods in 2000. The primary reason for the decreased sales in the third quarter of 2001 was the result of a 36 percent decrease in the average price of natural gas compared to the same period in 2000. The nine month increase in gas sales is the result of a 36 percent increase in the price of natural gas coupled with a six percent increase in the average daily production of natural gas, compared to the same period in 2000.

Oil sales for the Company, excluding third party sales by Noble Trading, Inc. ("NTI"), a wholly owned subsidiary of the Company, increased eight percent and 15 percent for the three months and nine months ended September 30, 2001 compared with the same periods in 2000. The increase in sales was due to an increase in average daily production of 22 percent and 16 percent, respectively, for the three months and nine months ended September 30, 2001 compared with the same periods in 2000.

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 third quarter of 2001, revenues and expenses from NGM and NTI third party sales totaled $134.4 million and $130.8 million, respectively, for a combined gross margin of $3.6 million. In comparison, for the third quarter of 2000, NGM and NTI third party sales and expenses of $145.9 million and $142.8 million, respectively, resulted in a combined gross margin of $3.1 million. For the nine months ended September 30, 2001, combined NGM and NTI revenues and expenses from third party sales totaled $562.4 million and $552.5 million, respectively, for a gross margin of $9.9 million. In comparison, combined NGM and NTI third party sales and expenses of $396.4 million and $386.6 million, respectively, resulted in a gross margin of $9.8 million for the same period in 2000.

The Company, through its subsidiaries, from time to time, uses various hedging arrangements in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations. Such arrangements include fixed price hedges, costless collars, and other contractual arrangements. Although these hedging arrangements expose the Company to credit risk, the Company monitors the creditworthiness of its counterparties, which generally are major financial institutions, and believes that losses from nonperformance are unlikely to occur. Hedging gains and losses related to the Company's oil and gas production are recorded in oil and gas sales and royalties upon settlement. For more information, see "Item 3. Quantitative and Qualitative Disclosures About Market Risk" of this Form 10-Q.

The Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standard ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities" in June 1998. The Statement establishes accounting and reporting standards requiring every derivative instrument (including certain derivative instruments embedded in other contracts) to be recorded in the balance sheet as either an asset or liability measured at its fair value. The Statement requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met wherein gains and losses are reflected in stockholder equity until the hedged item is recognized. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

SFAS No. 133 was required to be applied to (a) derivative instruments and (b) certain derivative instruments embedded in hybrid contracts that were issued, acquired, or substantively modified after December 31, 1997 (and, at the Company's election, before January 1, 1998). Due to the adoption of SFAS Nos. 133 and 138, NGM recorded on the Balance Sheet and Statement of Other Comprehensive Income and Equity, $52.7 million in other current assets; $41.4 million in other current liabilities; $642.5 thousand in long term assets; and $509.0 thousand in other income from hedging transactions for the first nine months of 2001.

Certain selected oil and gas operating statistics follow:

	For the three months ended September 30,		For the nine months ended September 30,	
	2001	2000	2001	2000
Oil revenue (in thousands)..........................	$ 64,346	$ 59,782	$ 190,510	$ 165,786
Average daily oil production - BBLS.................	31,665	25,863	29,773	25,624
Average oil price per BBL..........................	$ 22.50	$ 25.76	$ 23.95	$ 24.23
Gas revenues (in thousands).........................	$ 99,958	$ 147,161	$ 506,555	$ 353,381
Average daily gas production - MCF..................	431,132	401,084	427,151	401,857
Average gas price per MCF..........................	$ 2.60	$ 4.07	$ 4.46	$ 3.28

BBLS - BARRELS
MCF - THOUSAND CUBIC FEET

Oil and gas exploration expense increased $31.4 million and $69.4 million for the three months and nine months ended September 30, 2001, as compared with the same periods of 2000. These increases are attributable to a $26.4 million increase in dry hole expense, a $1.6 million increase in undeveloped lease amortization and a $3.6 million increase in seismic for the three months ended September 30, 2001. For the nine months ended September 30, 2001, as compared with the same periods of 2000, there was a $61.6 million increase in dry hole expense and a $3.8 million increase in undeveloped lease amortization.

Oil and gas operations expense decreased $2.0 million and increased $10.5 million for the three months and nine months ended September 30, 2001, as compared with the same periods of 2000. These variances are primarily attributable to decreases in lease operations expense for the three months and increases in lease operations expense for the nine months ended September 30, 2001, as compared with the same periods of 2000.

Depreciation, depletion and amortization (DD&A) expense increased 20 percent and 27 percent, respectively, for the three months and nine months ended September 30, 2001 compared with the same periods in 2000. The unit rate of DD&A per barrel of oil equivalents (BOE), converting gas to oil on the basis of 6 MCF per barrel, was $7.61 for the first nine months of 2001 compared with $6.52 for the same period of 2000. The unit rate of DD&A per BOE was $7.20 for the three months ended September 30, 2001 compared with $6.69 for the same period of 2000. 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.

Interest expense increased 18 percent and nine percent for the three months and nine months ended September 30, 2001 as compared with the same periods of 2000. The increase in interest expense is attributable to an increase in credit facility borrowings during the first nine months of 2001.

FUTURE TRENDS

The Company expects increased oil and gas production in the fourth quarter of 2001 and in 2002 as compared to the fourth quarter of 2000. The increase in 2001 would be primarily due to the Cook and Hanze acquisitions in the North Sea. The Cook property was acquired in the fourth quarter of 2000 and its current gross production is approximately 21,000 barrels of oil per day. The Company owns a 12.24 percent interest in the Cook field. The Hanze field, located offshore Netherlands, is expected by yearend 2001 to have a production rate of approximately 31,500 barrels of oil per day. The Company owns a 15 percent interest in the Hanze field and first production began in the third quarter of 2001. The completion of the Alba field expansion in Equatorial Guinea and the startup of the methanol plant will utilize gas feedstock from the Alba field. Offshore Ecuador, the Amistad gas field development is expected to be completed and contributing to gas production and cash flow in 2002, as well as the Machala power project which will utilize gas from the Amistad gas field to supply electrical power. The China field development in the southern portion of Bohai Bay, from the Cheng Dao Xi Block, is projected to be completed with first oil production in the second quarter of 2002.

The Company set its 2001 capital expenditure budget at $727 million of which approximately $588.1 million has been expended through September 30, 2001. Remaining 2001 expenditures are planned to be funded through internally generated cash flows and borrowings from the $300 million credit facility. The Company believes that it is well positioned to take advantage of strategic acquisitions as they become available, through internally generated cash flows or borrowings from the $300 million credit facility.

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. 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. Out of the expanded $100 million repurchase program, approximately $70 million remains authorized to purchase additional shares. Under the original $50 million authorization, the Company repurchased approximately $30 million of common stock in the first quarter of 2000. The Company has not yet repurchased any additional shares under the expanded authorization.

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 controlling its exposure to price changes. The Company had no crude oil or natural gas hedges for its current production in the third quarter of 2001 except those entered into by NGM.

On August 16, 2001, the Company (floating price payor) entered into a total of three natural gas costless collar contracts related to its production. The first contract, for the fourth quarter of 2001, for 50,000 MMBTU of gas per day, has a floor price of $3.25 per MMBTU and a ceiling price of $4.60 per MMBTU. The other two contracts, for calendar year 2002, each for 25,000 MMBTU of gas per day, have a floor price of $3.25 per MMBTU and ceiling prices ranging from $5.05 to $5.10 per MMBTU. These contracts entitle the Company to receive settlement from the counterparty

(fixed price payor) on a calendar quarterly basis, in amounts, if any, by which the average settlement price for the last scheduled NYMEX trading day applicable for each month, per calendar quarter, is less than the floor price. The Company would pay the counterparty if the average settlement price for the last scheduled NYMEX trading day applicable for each month per calendar quarter is more than the ceiling price. The amount payable by the floating price payor, if the floating price is above the ceiling price, is the product of the notional quantity per calculation period and the excess, if any, of the floating price over the ceiling price in respect of each calendar quarter. The amount payable by the fixed price payor, if the floating price is below the floor price, is the product of the notional quantity per calculation period and the excess, if any, of the floor price over the floating price in respect of each calendar quarter.

For calendar year 2000, the Company had entered into three crude oil premium swap contracts related to its production. Two of the contracts provided for payments based on daily NYMEX settlement prices. These contracts related to 2,500 BBLS per day and 2,000 BBLS per day and had trigger prices of $21.73 per BBL and $22.45 per BBL, respectively, and both had knockout prices of $17.00 per BBL. These two contracts entitled the Company to receive settlements from the counterparties in amounts, if any, by which the settlement price for each NYMEX trading day was less than the trigger price, provided the NYMEX price was also greater than the $17.00 per BBL knockout price. If a daily settlement price was $17.00 per BBL or less, then neither party had any liability to the other for that day. If a daily settlement price was above the applicable trigger price, then the Company would have owed the counterparty for the excess of the settlement price over the trigger price for that day. Payment was made monthly under each of these contracts, in an amount equal to the net amount due to either party based on the sum of the daily amounts determined as described in this paragraph for that month.

The third contract related to 2,500 BBLS per day and provided for payments based on monthly average NYMEX settlement prices. The contract entitled the Company to receive monthly settlements from the counterparty in an amount, if any, by which the arithmetic average of the daily NYMEX settlement prices for the month was less than the trigger price, which was $21.73 per BBL, multiplied by the number of days in the month, provided such average NYMEX price was also greater than the $17.00 per BBL knockout price. If the average NYMEX settlement price for the month was $17.00 per BBL or less, then neither party would have had any liability to the other for that month. If the average NYMEX settlement price for the month was above the trigger price, then the Company would have paid the counterparty an amount equal to the excess of the average settlement price over the trigger price, multiplied by the number of days in the month.

The Company treated the swap component of these contracts as a hedge (for accounting purposes only), at swap prices ranging from $19.40 per BBL to $20.20 per BBL, which existed at the dates it entered into these contracts. In addition, the Company separately accounted for the premium component of these contracts by marking them to market, resulting in a gain of $1,663,000 and $2,920,000 recorded in other income for the three months and nine months ended September 30, 2000, respectively.

The effect of these premium swap hedges was a $3.23 per BBL reduction in the average crude oil price for the third quarter of 2000. For the nine months ended September 30, 2000, the net effect of the premium swap hedges was a $2.73 per BBL reduction in the average crude oil price. Premium swap hedges for October 2000 through December 2000, which averaged 7,000 BBLS per day, were not closed at September 30, 2000.

NGM, from time to time, employs hedging 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 September 30, 2001 the Company had no material market risk exposure from NGM's hedging activity. During the third quarter of 2001, NGM had hedging transactions with broker-dealers that represented approximately 1,473,000 MMBTU's of gas per day. Hedges for October 2001 through May 2006, which range from 20,000 MMBTU's to 1,056,000 MMBTU's of gas per day, for future physical transactions, were not closed at September 30, 2001. During the third quarter of 2000, NGM had hedging transactions with broker-dealers that represented approximately 948,000 MMBTU's of gas per day. For the nine months ended September 30, 2001, NGM had hedging transactions that represented approximately 1,290,000 MMBTU's of gas per day, compared with 697,000 MMBTU's of gas per day for the same period in 2000.

The Company has a $300 million credit agreement which exposes the Company to the risk of earnings or cash flow loss due to changes in market interest rates. At September 30, 2001, the Company had $190 million outstanding on its $300 million credit facility, which has a maturity date of December 24, 2002. The interest rate is based upon a

Eurodollar rate plus a range of 17.5 to 50 basis points. 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 information required by this Item 6(a) is set forth in the Index to Exhibits accompanying this quarterly report on Form 10-Q.

(b) The Company did not file any reports on Form 8-K during the three months ended September 30, 2001.

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 AFFILIATES, INC.
(Registrant)

Date November 13, 2001 /s/ JAMES L. McELVANY

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

INDEX TO EXHIBITS

Exhibit
Number
Exhibit
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- None