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

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2002

OR

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

For the transition period from _____to_____

Commission file number: 001-07964

NOBLE ENERGY, 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)*

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

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

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $3.33-1/3 par value	New York Stock Exchange, Inc.
Preferred Stock Purchase Rights	New York Stock Exchange, Inc.

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT: None

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______

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.___X__

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes__X___ No______

Aggregate market value of Common Stock held by nonaffiliates as of June 28, 2002: $1,934,000,000.
Number of shares of Common Stock outstanding as of February 27, 2003: 57,384,490.

DOCUMENT INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2003 Annual Meeting of Stockholders to be held on April 29, 2003, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2002, are incorporated by reference into Part III.

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PART I

Item 1. Business.

This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. For more information, see "Item 7a. Quantitative and Qualitative Disclosures About Market Risk - Cautionary Statement for Purposes of the Private Securities Litigation Reform Act of 1995 and Other Federal Securities Laws" of this Form 10-K.

General

Noble Energy, Inc. (the "Company" or "Noble Energy"), the successor to Noble Affiliates, Inc., is a Delaware corporation that has been publicly traded on the New York Stock Exchange for over 20 years. Noble Energy is principally engaged, directly or through its subsidiaries, in the exploration, production and marketing of crude oil and natural gas. The Company is noted for its innovative methods of marketing its international gas reserves through projects such as its methanol plant in Equatorial Guinea and its gas-to-power project in Ecuador.

In this report, unless otherwise indicated or the context otherwise requires, the "Company" or the "Registrant" refers to Noble Energy, Inc. and its subsidiaries. Effective December 31, 2001, Energy Development Corporation ("EDC") was merged into Samedan Oil Corporation ("Samedan"). Effective December 31, 2002, Samedan was merged into Noble Energy, Inc. Effective December 31, 2002, Noble Trading, Inc. ("NTI") was merged into Noble Gas Marketing, Inc. ("NGM") under the name of Noble Energy Marketing, Inc. ("NEMI").

As of January 1, 2003, the Company's wholly-owned subsidiary, NEMI, markets the majority of the Company's domestic natural gas as well as third-party natural gas. NEMI also markets a portion of the Company's domestic crude oil as well as third-party crude oil. For more information regarding NEMI's operations, see "Item 1. Business--Crude Oil and Natural Gas--Marketing" of this Form 10-K.

In this report, the following abbreviations are used:

Bbl	Barrel	Mcf	Thousand cubic feet
Bbls	Barrels	Mcfe	Thousand cubic feet equivalent
MBbls	Thousand barrels	MMcf	Million cubic feet
Bpd	Barrels per day	MMcfepd	Million cubic feet equivalent per day
Bopd	Barrels oil per day	MMcfpd	Million cubic feet per day
MMBbl	Million barrels	Bcf	Billion cubic feet
MBpd	Thousand barrels per day	Bcfe	Billion cubic feet equivalent
MMBpd	Million barrels per day	Bcfepd	Billion cubic feet equivalent per day
MBopd	Thousand barrels oil per day	Bcfpd	Billion cubic feet per day
MMBopd	Million barrels oil per day	Tcf	Trillion cubic feet
BOE	Barrels oil equivalent	Tcfe	Trillion cubic feet equivalent
MMBoe	Million barrels oil equivalent	BTU	British thermal unit
MMBoepd	Million barrels oil equivalent per day	BTUpcf	British thermal unit per cubic foot
$MM	Millions of dollars	MMBTU	Million British thermal unit
Kwh	Kilowatt hour	MMBTUpd	Million British thermal unit per day
MW	Megawatt	MTpd	Metric tons per day
MWH	Megawatt hours	LPG	Liquefied petroleum gas

For reporting BOE or Mcfe, one Bbl of oil or condensate is equal to six Mcf of natural gas.

Crude Oil and Natural Gas

Noble Energy, directly or through its subsidiaries or various arrangements with other companies, explores for, develops and produces crude oil and natural gas. Exploration activities include geophysical and geological evaluation and exploratory drilling on properties for which the Company has exploration rights. Noble Energy has been engaged in the exploration, production and marketing of crude oil and natural gas since 1932. The Company has exploration, exploitation and production operations domestically and internationally. The domestic areas consist of: offshore in the Gulf of Mexico and California; the Gulf Coast Region (Louisiana, New Mexico and Texas); the Mid-Continent Region (Oklahoma and Kansas); and the Rocky Mountain Region (Colorado, Montana, North Dakota, Wyoming and California). The international areas of operations include Argentina, China, Ecuador, Equatorial Guinea, the Mediterranean Sea (Israel), the North Sea (Denmark, Netherlands and United Kingdom) and Vietnam. For more information regarding Noble Energy's crude oil and natural gas properties, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

Exploration, Exploitation and Development Activities

Domestic Offshore. Noble Energy has been actively engaged in exploration, exploitation and development of crude oil and natural gas properties in the Gulf of Mexico (Texas, Louisiana, Mississippi and Alabama) and California since 1968. The Company has shifted its domestic offshore exploration focus to the Gulf of Mexico deep shelf and deepwater areas, and away from the Gulf of Mexico's conventional shallow shelf, in order to take advantage of lower operating costs, larger prospect sizes and higher rates of return. The Company's current offshore production is derived from 194 gross wells operated by Noble Energy and 304 gross wells operated by others. At December 31, 2002, the Company held offshore federal leases covering 982,733 gross developed acres and 764,682 gross undeveloped acres on which the Company currently intends to conduct future exploration activities. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

Domestic Onshore. Noble Energy has been actively engaged in exploration, exploitation and development of crude oil and natural gas properties in three regions since the 1930s. The Gulf Coast Region covers onshore Louisiana, New Mexico and Texas. The Mid-Continent Region covers Oklahoma and Kansas. Properties in the Rocky Mountain Region are located in Colorado, Montana, North Dakota, Wyoming and California.

Noble Energy's current onshore production is derived from 1,496 gross wells operated by the Company and 1,238 gross wells operated by others. At December 31, 2002, the Company held 685,162 gross developed acres and 398,815 gross undeveloped acres onshore on which the Company may conduct future exploration activities. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

Argentina. Noble Energy has been actively engaged in exploration, exploitation and development of crude oil and natural gas properties in Argentina since 1996. The Company's producing properties are located in southern Argentina in the El Tordillo field, which is characterized by secondary recovery crude oil production from a 10,000 acre reservoir. At December 31, 2002, the Company held 28,988 gross developed acres and 2,398,970 gross undeveloped acres in Argentina on which the Company may conduct future exploration activities. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

China. Noble Energy has been actively engaged in exploration, exploitation and development of crude oil and natural gas properties in China since 1996. The Company has two concessions offshore China. These concessions, Cheng Dao Xi and Cheng Zi Kou, are contiguous and adjoin non-owned production in the southern portion of Bohai Bay. At December 31, 2002, the Company held 7,413 gross developed acres and 2,569,522 gross undeveloped acres in China on which the Company may conduct future exploration activities. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

Ecuador. Noble Energy has been actively engaged in exploration, exploitation and development of crude oil and natural gas properties in Ecuador since 1996. The Company is currently utilizing the gas in the Amistad gas field (offshore Ecuador), which was discovered in the 1970s, to generate electricity through its 100 percent owned natural gas-fired power plant, located near the city of Machala. Currently generating 130 MW, with additional capital investment, the power plant will ultimately be capable of generating 220 MW of electricity into the Ecuadorian power grid. The concession covers 12,355 gross developed acres and 851,771 gross undeveloped acres encompassing the Amistad field. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

Equatorial Guinea. Noble Energy has been actively engaged in exploration, exploitation and development of crude oil and natural gas properties offshore Equatorial Guinea (West Africa) since 1990. The offshore Equatorial Guinea production is from the Alba field, which produces natural gas and condensate. The majority of the natural gas production is sold to a methanol plant, which began production in the second quarter of 2001. The methanol plant has a 25-year contract to purchase natural gas from the Alba field. The plant is owned by Atlantic Methanol Production Company LLC ("AMPCO"), in which the Company indirectly owns a 45 percent interest through its ownership of Atlantic Methanol Capital Company ("AMCCO"). For more information on the methanol plant, see "Item 1. Business--Unconsolidated Subsidiary" of this Form 10-K.

At December 31, 2002, the Company held 45,203 gross developed acres and 266,754 gross undeveloped acres offshore Equatorial Guinea on which the Company may conduct future exploration activities. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

Israel. Noble Energy has been actively engaged in exploration, exploitation and development of crude oil and natural gas properties in the Mediterranean Sea, offshore Israel, since 1998. The Company owns a 47 percent interest in 11 licenses and two leases. At December 31, 2002, the Company held 123,552 gross developed acres and 1,028,796 gross undeveloped acres located about 20 miles offshore Israel in water depths ranging from 700 feet to 5,000 feet. Noble Energy and its partners announced on June 25, 2002 they had executed a definitive agreement for the sale of natural gas to Israel Electric Corporation ("IEC"). For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

North Sea. Noble Energy has been actively engaged in exploration, exploitation and development of crude oil and natural gas properties in the North Sea (Denmark, Netherlands and United Kingdom) since 1996. At December 31, 2002, the Company held 81,675 gross developed acres and 677,029 gross undeveloped acres on which the Company may conduct future exploration activities. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

Vietnam. Noble Energy owns a 77 percent interest in two offshore blocks totaling 1,701,812 gross undeveloped acres in the Nam Con Son Basin. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

Production Activities

Operated Property Statistics. The percentage of crude oil and natural gas wells operated and the percentage of sales volume from operated properties are shown in the following table as of December 31:

	2002		*2001*		*2000*	
(in percentages)	*Oil*	*Gas*	*Oil*	*Gas*	*Oil*	*Gas*
Operated well count basis	23.3	62.8	24.8	60.6	23.1	66.0
Operated sales volume basis	29.3	45.1	37.2	52.3	48.3	64.5

Net Production. The following table sets forth Noble Energy's net crude oil and natural gas production, including royalty, for the three years ended December 31:

	2002	*2001*	*2000*
Crude Oil Production (MMBbl)	12.4	11.2	9.4
Natural Gas Production (Bcf)	141.5	154.2	148.7

Crude Oil and Natural Gas Equivalents. The following table sets forth Noble Energy's net production stated in crude oil and natural gas equivalent volumes, for the three years ended December 31:

	2002	*2001*	*2000*
Total Crude Oil Equivalents (MMBoe)	36.0	36.9	34.2
Total Natural Gas Equivalents (Bcfe)	216.0	221.3	205.4

Acquisitions of Oil and Gas Properties, Leases and Concessions
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During 2002, Noble Energy spent approximately $8 million on the purchase of proved crude oil and natural gas properties. The Company spent approximately $98 million in 2001 and $99 million in 2000 on proved properties. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

During 2002, Noble Energy spent approximately $31 million on acquisitions of unproved properties. The Company spent approximately $81 million in 2001 and $18 million in 2000 on acquisitions of unproved properties. These properties were acquired primarily through various offshore lease sales, domestic onshore lease acquisitions and international concession negotiations. For more information, see "Item 2. Properties--Crude Oil and Natural Gas" of this Form 10-K.

Marketing

NEMI seeks opportunities to enhance the value of the Company's domestic natural gas by marketing directly to end users and aggregating gas to be sold to natural gas marketers and pipelines. During 2002, approximately 83 percent of NEMI's total sales were to end users. NEMI is also actively involved in the purchase and sale of natural gas from other producers. Such third-party natural gas may be purchased from non-operators who own working interests in the Company's wells or from other producers' properties in which the Company may not own an interest. NEMI, through its wholly-owned subsidiary, Noble Gas Pipeline, Inc., engages in the installation, purchase and operation of natural gas gathering systems.

Noble Energy has a short-term natural gas sales contract with NEMI, whereby the Company is paid an index price for all natural gas sold to NEMI. The Company sold approximately 66 percent of its natural gas production to NEMI in 2002. Third-party sales, including derivative transactions, are recorded as gathering, marketing and processing revenues. NEMI records the amount paid to Noble Energy and third parties as gathering, marketing and processing costs and expenses. All intercompany sales and expenses are eliminated in the Company's consolidated financial statements. The Company has a small number of long-term natural gas contracts representing less than four percent of its total natural gas sales.

Crude oil produced by the Company is sold to purchasers in the United States and foreign locations at various prices depending on the location and quality of the crude oil. The Company has no long-term contracts with purchasers of its crude oil production. Crude oil and condensate are distributed through pipelines and by trucks to gatherers, transportation companies and end users. NEMI markets approximately 30 percent of the Company's crude oil production as well as certain third-party crude oil. The Company records all of NEMI's sales as gathering, marketing and processing revenues and records cost of sales in gathering, marketing and processing costs. All intercompany sales and expenses are eliminated in the Company's consolidated financial statements.

Crude oil prices are affected by a variety of factors that are beyond the control of the Company. The Company's average crude oil price increased $.68 from $23.30 per Bbl in 2001 to $23.98 per Bbl in 2002. Due to the volatility of crude oil prices, the Company, from time to time, has used hedging instruments and may do so in the future as a means of controlling its exposure to price changes. For additional information, see "Item 7a. Quantitative and Qualitative Disclosures About Market Risk" and "Item 8. Financial Statements and Supplementary Data" of this Form 10-K.

Substantial competition in the natural gas marketplace continued in 2002. The Company's average natural gas price decreased from $3.98 per Mcf in 2001 to $2.92 per Mcf in 2002. Due to the volatility of natural gas prices, the Company, from time to time, has used hedging instruments and may do so in the future as a means of controlling its exposure to price changes. For additional information, see "Item 7a. Quantitative and Qualitative Disclosures About Market Risk" and "Item 8. Financial Statements and Supplementary Data" of this Form 10-K.

The largest single non-affiliated purchaser of the Company's crude oil production in 2002 accounted for approximately 15 percent of the Company's crude oil sales, representing approximately three percent of total revenues. The five largest purchasers accounted for approximately 50 percent of total crude oil sales. The largest single non-affiliated purchaser of the Company's natural gas production in 2002 accounted for approximately six percent of its natural gas sales, representing approximately two percent of total revenues. The five largest purchasers accounted for approximately 16 percent of total natural gas sales. The Company does not believe that its loss of a major crude oil or natural gas purchaser would have a material effect on the Company.

Regulations and Risks

General. Exploration for and production and sale of crude oil and natural gas are extensively regulated at the international, national, state and local levels. Crude oil and natural gas development and production activities are subject to various laws and regulations (and orders of regulatory bodies pursuant thereto) governing a wide variety of matters, including allowable rates of production, prevention of waste and pollution and protection of the environment. Laws affecting the crude oil and natural gas industry are under constant review for amendment or expansion and frequently increase the regulatory burden on companies. Noble Energy's ability to economically produce and sell crude oil and natural gas is affected by a number of legal and regulatory factors, including federal, state and local laws and regulations in the United States and laws and regulations of foreign nations. Many of these governmental bodies have issued rules and regulations that are often difficult and costly to comply with, and that carry substantial penalties for failure to comply. These laws, regulations and orders may restrict the rate of crude oil and natural gas production below the rate that would otherwise exist in the absence of such laws, regulations and orders. The regulatory burden on the crude oil and natural gas industry increases its costs of doing business and consequently affects the Company's profitability.

Certain Risks. In the Company's exploration operations, losses may occur before any accumulation of crude oil or natural gas is found. If crude oil or natural gas is discovered, no assurance can be given that sufficient reserves will be developed to enable the Company to recover the costs incurred in obtaining the reserves or that reserves will be developed at a sufficient rate to replace reserves currently being produced and sold. The Company's international operations are also subject to certain political, economic and other uncertainties including, among others, risk of war, expropriation, renegotiation or modification of existing contracts, taxation policies, foreign exchange restrictions, international monetary fluctuations and other hazards arising out of foreign governmental sovereignty over areas in which the Company conducts operations.

Environmental Matters. As a developer, owner and operator of crude oil and natural gas properties, the Company is subject to various federal, state, local and foreign country laws and regulations relating to the discharge of materials into, and the protection of, the environment. The unauthorized release or discharge of crude oil or certain other regulated substances from the Company's domestic onshore or offshore facilities could subject the Company to liability under federal laws and regulations, including the Oil Pollution Act of 1990, the Outer Continental Shelf Lands Act and the Federal Water Pollution Control Act, as amended. These laws, among others, impose liability for such a release or discharge for pollution cleanup costs, damage to natural resources and the environment, various forms of direct and indirect economic losses, civil or criminal penalties, and orders or injunctions, including those that can require the suspension or cessation of operations causing or impacting or potentially impacting such release or discharge. The liability under these laws for a substantial such release or discharge, subject to certain specified limitations on liability, may be extraordinarily large. If any pollution was caused by willful misconduct, willful negligence or gross negligence within the privity and knowledge of the Company, or was caused primarily by a violation of federal regulations, the Federal Water Pollution Control Act provides that such limitations on liability do not apply. Certain of the Company's facilities are subject to regulations that require the preparation and implementation of spill prevention control and countermeasure plans relating to the prevention of, and preparation for, the possible discharge of crude oil into navigable waters.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as "Superfund," imposes liability on certain classes of persons that generated a hazardous substance that has been released into the environment or that own or operate facilities or vessels onto or into which hazardous substances are disposed. The Resource Conservation and Recovery Act, as amended, ("RCRA") and regulations promulgated thereunder, regulate hazardous waste, including its generation, treatment, storage and disposal. CERCLA currently exempts crude oil, and RCRA currently exempts certain crude oil and natural gas exploration and production drilling materials, such as drilling fluids and produced waters, from the definitions of hazardous substance and hazardous waste, respectively. The Company's operations, however, may involve the use or handling of other materials that may be classified as hazardous substances and hazardous wastes, and therefore, these statutes and regulations promulgated under them would apply to the Company's generation, handling and disposal of these materials. In addition, there can be no assurance that such exemptions will be preserved in future amendments of such acts, if any, or that more stringent laws and regulations protecting the environment will not be adopted.

Certain of the Company's facilities may also be subject to other federal environmental laws and regulations, including the Clean Air Act with respect to emissions of air pollutants.

Certain state or local laws or regulations and common law may impose liabilities in addition to, or restrictions more stringent than, those described herein.

The environmental laws, rules and regulations of foreign countries are generally less stringent than those of the United States, and therefore, the requirements of such jurisdictions do not generally impose an additional compliance burden on the Company or on its subsidiaries.

The Company has made and will continue to make expenditures in its efforts to comply with environmental requirements. The Company does not believe that it has to date expended material amounts in connection with such activities or that compliance with such requirements will have a material adverse effect upon the capital expenditures, earnings or competitive position of the Company. Although such requirements do have a substantial impact upon the energy industry, generally they do not appear to affect the Company any differently or to any greater or lesser extent than other companies in the industry.

Insurance. The Company has various types of insurance coverages as are customary in the industry which include, in various degrees, general liability, well control, pollution and physical damage insurance. The Company believes the coverages and types of insurance are adequate.

Competition

The oil and gas industry is highly competitive. Many companies and individuals are engaged in exploring for crude oil and natural gas and acquiring crude oil and natural gas properties, resulting in a high degree of competition for desirable exploratory and producing properties exists. A number of the companies with which the Company competes are larger and have greater financial resources than the Company.

The availability of a ready market for the Company's crude oil and natural gas production depends on numerous factors beyond its control, including the level of consumer demand, the extent of worldwide crude oil and natural gas production, the costs and availability of alternative fuels, the costs and proximity of pipelines and other transportation facilities, regulation by state and federal authorities and the costs of complying with applicable environmental regulations.

Unconsolidated Subsidiary

Prior to January 2002, AMCCO was a 50 percent owned joint venture that owned an indirect 90 percent interest in 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 December 15, 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 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's debt 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 total construction costs of the plant and supporting facilities as of December 31, 2002 were $417 million, with the Company responsible for $208.5 million. The plant is designed to produce 2,500 MTpd of methanol, which equates to approximately 20,000 Bpd. At this level of production, the plant would purchase approximately 125 MMcfpd from the 34 percent owned Alba field. The methanol plant has a 25-year contract to purchase natural gas from the Alba field. For more information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data--Note 9 - Unconsolidated Subsidiary" of this Form 10-K.

Geographical Data

The Company has operations throughout the world and manages its operations by country. Information is grouped into five components that are all primarily in the business of natural gas and crude oil exploration, exploitation and production: United States, Equatorial Guinea, Mediterranean Sea, North Sea and Other International. For more information, see "Item 8. Financial Statements and Supplementary Data--Note 11 - Geographical Data" of this Form 10-K.

Employees

The total number of employees of the Company increased during the year from 610 at December 31, 2001, to 624 at December 31, 2002. Eighty foreign nationals worked in Noble Energy offices in China, Ecuador, Israel and Vietnam as of December 31, 2002.

Available Information

The Company's website address is *www.nobleenergyinc.com*. Available on this website under "Investor Relations - Investor Relations Menu - SEC Filings," free of charge, are Noble Energy's annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after such materials are electronically filed with or furnished to the United States Securities and Exchange Commission ("SEC").

Item 2. Properties.

Offices

The principal corporate office of the Registrant is located in Houston, Texas. The Company maintains offices for international, domestic onshore and domestic offshore operations in Houston, Texas. The Company also maintains offices in China, Ecuador, Israel, the United Kingdom and Vietnam. NEMI's office is located in Houston, Texas. The Company also maintains offices in Ardmore, Oklahoma for centralized accounting, division orders, employee benefits and related administrative functions.

Crude Oil and Natural Gas

The Company, directly or through its subsidiaries or various arrangements with other companies, searches for potential crude oil and natural gas properties, seeks to acquire exploration rights in areas of interest and conducts exploratory activities. These activities include geophysical and geological evaluation and exploratory drilling, where appropriate, on properties for which it acquired exploration rights. During 2002, Noble Energy drilled or participated in the drilling of 194 gross (90.0 net) wells, comprised of 59 gross (16.1 net) international wells and 135 gross (73.9 net) domestic wells. For more information regarding Noble Energy's oil and gas properties, see "Item 1. Business--Crude Oil and Natural Gas" of this Form 10-K.

Domestic Offshore. Noble Energy's first operated commercial deepwater natural gas discovery in East Breaks 421 (Lost Ark) commenced production ahead of schedule in the second quarter of 2002. Production began at an initial rate of 40 MMcfpd. Noble Energy has a 48 percent working interest in Lost Ark.

Another deepwater natural gas discovery, Green Canyon 136 A-8 (Shasta), commenced production in January 2003 at 25 MMcfpd. Noble Energy has a 25 percent working interest in Shasta.

Green Canyon 282 (Boris), a deepwater crude oil discovery, commenced production from its first well during the first quarter of 2003 at 9,500 Bopd. The second well is expected to commence production by mid-year 2003 at an additional 8,000 Bopd. Noble Energy has a 25 percent working interest in Boris.

Another deepwater crude oil discovery, Viosca Knoll 917/961/962 (Swordfish), is expected to commence production during 2004.

Highlights of the 2002 deep shelf program include several key properties. In the first quarter, Eugene Island 97 #3 (Thunderbolt), in which the Company has a 25 percent working interest, commenced production at 15 MMcfpd. During the second quarter, Main Pass 108 B-3 commenced production at 15 MMcfpd, and Viosca Knoll 68 #4 commenced production at 16 MMcfpd. The Company has a 25 percent and 30 percent working interest in these wells, respectively. Noble Energy has a 31 percent working interest in Ship Shoal 225 #1 that commenced production in the third quarter at 750 Bopd. During the fourth quarter, production of 36 MMcfpd commenced from the Viosca Knoll 384 A-1 and A-2. Noble Energy has a 24 percent working interest in these wells.

During 2002, the Company expensed eight exploratory wells related to its offshore activity.

Noble Energy was the successful bidder, alone or with partners, on 17 of 20 lease blocks at the Central Gulf of Mexico Outer Continental Shelf Sale 182. Fifteen of the Company's 17 bids were approved with two being rejected. Of the 15 approved bids, nine were on blocks in deepwater, five were on blocks in the deep shelf, and the remaining block was in the conventional shelf. Approved bids totaled approximately $9.2 million net to the Company's interest. Noble Energy will be the designated operator on 12 of the blocks.

Domestic Onshore. During the fourth quarter of 2001, Noble Energy acquired all of the Gulf Coast onshore producing properties of Aspect Energy. As part of the transaction, Noble Energy and Aspect Energy established a joint venture to explore for and produce crude oil and natural gas. The area of mutual interest extends from Matagorda County, Texas to Lafayette Parish, Louisiana and includes 7,250 square miles of 3D seismic. This extensive 3D seismic database enhances Noble Energy's long-term domestic onshore position by providing a significant number of future exploration opportunities. During 2002, the joint venture drilled 45 wells, of which 26 wells, or 58 percent, were successful.

During the second quarter of 2002, the Company acquired an interest in the Bendito project in Matagorda County, Texas. The acquisition consisted of five producing wells in which Noble Energy owns a 35 percent working interest, 3,000 gross developed acres, 8,100 gross undeveloped acres, multiple 3D seismic defined prospects and a license to 45 square miles of proprietary 3D seismic data. The Steele #1, in which the Company owns a 29 percent working interest, was the initial exploratory test well in the Lower Frio trend of the Bendito project, drilled in late 2002 and tested at 5.1 MMcfpd and 310 Bopd.

Another domestic onshore exploration project in 2002 was Wildcat Ridge, which includes a 120 square mile proprietary 3D seismic survey in southeast Texas and southwest Louisiana. Initial drilling commenced in late 2002 with the Doornbos #1, in which Noble Energy owns a 35 percent working interest, discovering Miocene reserves in multiple zones. The W&T Offshore #1, in which the Company owns a 38 percent working interest, spud in January 2003, is the second successful well within the project. An additional well, the Noble Heirs #1, in which the Company owns a 38 percent working interest, commenced drilling in February 2003. In addition, technical analysis continues on several other identified prospects within the Wildcat Ridge project area.

During 2002, the Company expensed 24 exploratory wells related to its onshore activity.

Argentina. Noble Energy participated with a 13 percent working interest in 37 exploitation wells in the El Tordillo field during 2002. The Company has been awarded, and is awaiting final government approval of, a crude oil and natural gas exploration permit of approximately 1.2 million acres. The permit is located in the Cuyo Basin of Mendoza Province in western Argentina. The Company was the successful bidder on an adjacent permit of approximately 1.1 million acres.

China. Noble Energy completed its development of the Cheng Dao Xi (CDX) field in December 2002. The Company has a 57 percent working interest in CDX, which is located on the south side of Bohai Bay off the coast of China. Initial production of 6,000 Bopd (3,420 Bopd net to Noble Energy) from CDX commenced on January 13, 2003. The facilities on CDX have production capacity of 10,000 Bopd.

During 2002, the Company expensed three exploratory wells related to its activity in China. In early February 2003, an exploratory well in the South China Sea commenced drilling, with the Company having a 50 percent working interest.

Ecuador. In September 2002, Noble Energy commenced operations of its 100 percent owned fully integrated gas-to-power project ahead of schedule. The project includes the Amistad field, which is located in the shallow waters of the Gulf of Guayaquil near the coast of Ecuador. To date, Noble Energy has completed three development wells in the Amistad field that supply approximately 30 MMcfpd of natural gas to the Machala power plant. The power plant is located on the coast near Machala, Ecuador and connects to the Amistad field via a 40-mile pipeline. Machala Power is the only natural gas-fired commercial power generator in Ecuador. The Machala power plant currently has generating capacity of 130 MW from twin General Electric Frame 6Fa turbines.

Equatorial Guinea. During 2002, Noble Energy and its partners obtained approval from the government of Equatorial Guinea for phases 2A and 2B Alba field expansion projects. Phase 2A, which is scheduled to be completed in the fourth quarter of 2003, is expected to increase gross condensate production by approximately 29,000 Bopd (8,900 Bopd net to Noble Energy).

Phase 2B, which is scheduled to be completed during the fourth quarter of 2004, is expected to increase gross production of LPG by approximately 14,000 Bpd (3,900 Bpd net to Noble Energy) and gross condensate production by approximately 6,000 Bopd (1,700 Bopd net to Noble Energy). The project includes increasing processing capacity, storage and offloading facilities at the existing LPG plant. A fractionation unit will also be installed.

Following the completion of phases 2A and 2B, gross condensate and LPG capacity will be approximately 54,000 Bopd (16,000 Bopd net to Noble Energy) and 16,000 Bpd (4,500 Bpd net to Noble Energy), respectively.

Noble Energy holds a 34 percent working interest in the Alba field and related condensate production facilities, a 28 percent working interest in the Bioko Island LPG plant and a 45 percent working interest in the AMPCO plant that purchases and processes approximately 125 MMcfpd of natural gas into 2,500 MTpd of methanol. During 2002, 17 shipments of methanol were delivered, eight to European markets and nine to markets in the United States.

Israel. The Company and its partners signed a definitive agreement to provide approximately 170 MMcfpd of natural gas for use in IEC's power plants. Natural gas will be produced from the Mari-B field, offshore Israel, which was discovered in 2000. Production is anticipated to begin during the fourth quarter of 2003. Noble Energy has a 47 percent working interest in the project.

North Sea. The Company continued to focus on production and exploration growth in 2002. Two new licenses (P1047 and P1041) were awarded to Noble Energy in 2002 from the United Kingdom's 20th Licenses Bid Round. The Company expects to participate in five exploration wells in 2003, including the Company-operated Joppa prospect.

Vietnam. The Company continues to evaluate prospects in the two blocks of the Nam Con Son Basin in order to supplement the Swan discovery well of 2001. During 2002, the Company expensed one exploratory well.

Net Exploratory and Developmental Wells. The following table sets forth, for each of the last three years, the number of net exploratory and development wells drilled by or on behalf of Noble Energy. An exploratory well is a well drilled to find and produce crude oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of crude oil or natural gas in another reservoir, or to extend a known reservoir. A development well, for purposes of the following table and as defined in the rules and regulations of the SEC, is a well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive. The number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated. Completion refers to the installation of permanent equipment for the production of crude oil or natural gas, or in the case of a dry hole, to the reporting of abandonment to the appropriate agency.

	Net Exploratory Wells				*Net Development Wells*			
	Productive(1)		*Dry(2)*		*Productive(1)*		*Dry(2)*	
Year Ended December 31,	*U.S.*	*Int'l*	*U.S.*	*Int'l*	*U.S.*	*Int'l*	*U.S.*	*Int'l*
2002	9.78		11.45	3.27	41.53	12.84	11.17	
2001	4.87	.63	10.79	5.41	68.30	13.67	12.88	1.62
2000	17.86	3.94	10.59	1.00	101.89	5.99	4.17	.57

(1) A productive well is an exploratory or a development well that is not a dry hole.

(2) A dry hole is an exploratory or development well found to be incapable of producing either crude oil or natural gas in sufficient quantities to justify completion as an oil or gas well.

At January 31, 2003, Noble Energy was drilling 5 gross (2.3 net) exploratory wells and 5 gross (.8 net) development wells. These wells are located onshore in Louisiana, Wyoming and Argentina and offshore in the Gulf of Mexico and Equatorial Guinea. These wells have objectives ranging from approximately 5,110 feet to 14,075 feet. The drilling cost to Noble Energy of these wells will be approximately $7 million if all are dry and approximately $11 million if all are completed as producing wells.

Crude Oil and Natural Gas Wells. The number of productive crude oil and natural gas wells in which Noble Energy held an interest as of December 31 follows:

	2002(1)(2)		2001(1)(2)		2000(1)(2)	
	Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*
Crude Oil Wells						
United States – Onshore	1,131.0	458.7	1,364.5	573.6	1,341.5	564.0
United States – Offshore	232.5	95.7	212.5	120.0	210.5	119.2
International	687.0	81.3	670.0	75.7	604.0	66.2
Total	2,050.5	635.7	2,247.0	769.3	2,156.0	749.4
Natural Gas Wells						
United States – Onshore	1,603.0	1,006.6	1,673.5	1,025.7	1,532.5	947.1
United States – Offshore	265.5	184.9	333.5	143.3	300.5	133.4
International	42.0	13.1	38.0	8.4	31.0	3.5
Total	1,910.5	1,204.6	2,045.0	1,177.4	1,864.0	1,084.0

(1) Productive wells are producing wells and wells capable of production. A gross well is a well in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned. A net well is deemed to exist when the sum of fractional ownership working interests in gross wells equals one. The number of net wells is the sum of the fractional working interests owned in gross wells expressed as whole numbers and fractions thereof.

(2) One or more completions in the same borehole are counted as one well in this table.

The following table summarizes multiple completions and non-producing wells as of December 31 for the years shown. Included in wells not producing are productive wells awaiting additional action, pipeline connections or shut-in for various reasons.

	2002		2001		2000	
	Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*
Multiple Completions						
Crude Oil	12.0	6.0	13.5	6.9	13.5	6.9
Natural Gas	28.5	8.9	36.5	14.0	36.5	14.0
Not Producing (Shut-in)						
Crude Oil	565.0	212.3	391.0	179.2	386.0	177.5
Natural Gas	121.0	73.0	100.0	36.3	62.0	20.6

At year-end 2002, Noble Energy had less than eight percent of its crude oil and natural gas sales volumes committed to long-term supply contracts and had no similar agreements with foreign governments or authorities.

Since January 1, 2002, no crude oil or natural gas reserve information has been filed with, or included in any report to any federal authority or agency other than the SEC and the Energy Information Administration ("EIA"). Noble Energy files Form 23, including reserve and other information, with the EIA.

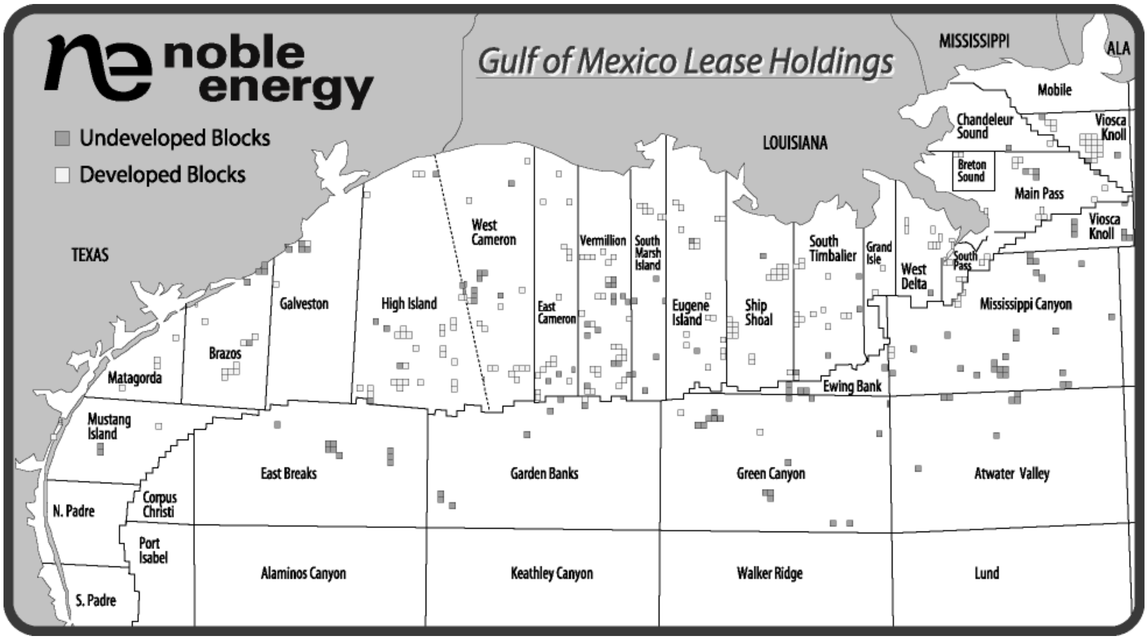
Average Sales Price. The following table sets forth, for each of the last three years, the average sales price per unit of crude oil produced and per unit of natural gas produced, and the average production cost per unit.

	Year Ended December 31,		
	2002	*2001*	*2000*
Average sales price per Bbl of crude oil (1):			
United States	$23.08	$22.88	$23.75
International	$24.98	$23.98	$28.28
Combined (2)	$23.98	$23.30	$24.95
Average sales price per Mcf of natural gas (1):			
United States	$ 3.20	$ 4.24	$ 3.90
International	$ 1.18	$ 1.60	$ 2.45
Combined (3)	$ 2.92	$ 3.98	$ 3.80
Average production (lifting) cost per Mcfe:			
United States	$ .70	$ .66	$ .59
International	$ .79	$ .46	$ .64
Combined	$ .70	$ .60	$ .59

(1) Net production amounts used in this calculation include royalties.

(2) Reflects a reduction of $.02 per Bbl in 2002 and $2.92 per Bbl in 2000 from hedging in the United States.

(3) Reflects an increase of $.04 per Mcf in 2002 and $.03 per Mcf in 2001 from hedging in the United States.



Significant Offshore Undeveloped Lease Holdings (interests rounded to nearest whole percent)

Block	Net Working Interest (%)
East Breaks	
279*	33
420*	48
464*	48
465*	48
475*	100
510*	33
519*	100
563*	100
Green Canyon	
23	100
27	43
85*	50
142	100
185*	100
186*	100
187*	100
227*	100
228*	100
303*	40
507*	50
723*	100
724*	100
768*	100
955*	7
958*	25
West Cameron	
136	40
392	100
393	100
400	100
419	100
422	50
438	100
443	100
446	100
Mustang Island	
829	80
830	80

Block	Net Working Interest (%)
Vermilion	
195	25
207	25
208	25
228	100
230	100
232	50
235	100
280	50
285	100
300	50
353	100
377	100
391	100
Garden Banks	
25	50
154	100
751*	100
795*	100
841*	39
Main Pass	
107	25
109	25
110	25
192	100
East Cameron	
342	67
348	30
355	100
South Timbalier	
62	100
98	50
156	67
278	50
315	40
Ship Shoal	
73	50

Block	Net Working Interest (%)
Galveston	
249-L	50
250-L	50
274-L	50
275-L	50
277-L	50
340-S	50
341-S	50
South Marsh Island	
38	100
64	67
70	50
145	100
167	100
195	50
Mississippi Canyon	
26*	75
70*	75
71*	75
123*	75
159*	75
204*	100
524*	50
583*	50
595*	24
602*	75
639*	24
665*	50
769*	100
811*	30
837*	40
849*	34
855*	30
856*	30
857*	30
896*	67
900*	30
901*	30
911*	40
999*	30
1000*	30

Block	Net Working Interest (%)
Brazos	
308-L	50
336-L	50
337-L	50
368-L	25
543	100
Ewing Bank	
834	14
949	52
993	98
995	43
996	43
Eugene Island	
96	25
317	67
High Island	
A-218	100
A-230	100
A-426	33
A-435	33
A-516	100
Viosca Knoll	
23	100
344	100
383	24
697	50
820	50
864*	35
908*	100
917*	10
961*	10
962*	10
Atwater Valley	
10*	100
11*	100
23*	100
66*	100
67*	100
327*	79
533*	40

*Located in water deeper than 1,000 feet.

The developed and undeveloped acreage (including both leases and concessions) that Noble Energy held as of December 31, 2002, is as follows:

	Developed Acreage (1)(2)		Undeveloped Acreage (2)(3)(4)	
Location	*Gross Acres*	*Net Acres*	*Gross Acres*	*Net Acres*
United States Onshore				
Alabama			2,657	506
California	4,902	2,048	5,002	3,832
Colorado	67,339	58,945	28,705	18,342
Kansas	93,918	52,833	17,803	11,907
Louisiana	52,151	9,162	38,023	10,002
Michigan			1,876	427
Mississippi	878	34	1,884	51
Montana	196,028	116,677	5,488	2,224
New Mexico	2,117	826	2,520	1,873
North Dakota	678	339	4,082	3,087
Oklahoma	144,373	52,972	19,191	7,207
Texas	86,073	40,144	196,038	61,008
Utah	5,160	2,433	4,956	4,254
Wyoming	31,545	18,831	70,590	47,272
Total United States Onshore	685,162	355,244	398,815	171,992
United States Offshore (Federal Waters)				
Alabama	103,680	43,430	41,661	25,123
California	38,834	12,039	52,364	9,422
Louisiana	591,963	251,317	407,705	288,823
Mississippi	28,171	15,809	119,024	55,199
Texas	220,085	100,490	143,928	92,094
Total United States Offshore (Federal Waters)	982,733	423,085	764,682	470,661
International				
Argentina	28,988	3,977	2,398,970	2,326,204
China	7,413	4,225	2,569,522	1,328,314
Denmark			81,050	32,420
Ecuador	12,355	12,355	851,771	851,771
Equatorial Guinea	45,203	15,727	266,754	92,808
Israel	123,552	58,142	1,028,796	338,538
Netherlands	865	130	74,749	11,212
United Kingdom	80,810	4,646	521,230	153,807
Vietnam			1,701,812	1,309,034
Total International	299,186	99,202	9,494,654	6,444,108
Total	1,967,081	877,531	10,658,151	7,086,761

(1) Developed acreage is acreage spaced or assignable to productive wells.

(2) A gross acre is an acre in which a working interest is owned. A net acre is deemed to exist when the sum of fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

(3) Undeveloped acreage is considered to be those leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves. Included within undeveloped acreage are those leased acres (held by production under the terms of a lease) that are not within the spacing unit containing, or acreage assigned to, the productive well so holding such lease.

(4) The Argentina acreage includes two concessions totaling 2,314,633 acres subject to final regulatory approval.

<u>Item 3.</u> **<u>Legal Proceedings.</u>**

(a) The Company and its subsidiaries are involved in various legal proceedings in the ordinary course of business. These proceedings are subject to the inherent uncertainties in any litigation. The Company is defending itself vigorously in all such matters and does not believe that the ultimate disposition of such proceedings will have a material adverse effect on the Company's consolidated financial position, results of operations or liquidity.

(b) On October 15, 2002, Noble Gas Marketing, Inc., Samedan Oil Corporation and Aspect Resources L.L.C., collectively referred to as the "Noble Defendants," filed proofs of claim in the United States Bankruptcy Court for the Southern District of New York in response to bankruptcy filings by Enron Corporation and certain of its subsidiaries and affiliates, including Enron North America Corporation ("ENA"), under Chapter 11 of the U.S. Bankruptcy Code. The proofs of claim relate to certain natural gas sales agreements and aggregate approximately $18 million.

On December 13, 2002, ENA filed a complaint in which it objected to the Noble Defendants' proofs of claim, sought recovery of approximately $60 million from the Noble Defendants under the natural gas sales agreements, sought declaratory relief in respect of the offset rights of the Noble Defendants and sought to invalidate the arbitration provisions contained in certain of the agreements in issue. The Noble Defendants intend to vigorously defend against ENA's claims and do not believe that the ultimate disposition of the bankruptcy proceeding will have a material adverse effect on the Company's consolidated financial position, results of operations or liquidity.

<u>Item 4.</u> **<u>Submission of Matters to a Vote of Security Holders.</u>**

There were no matters submitted to a vote of security holders during the fourth quarter of 2002.

Executive Officers of the Registrant

The following table sets forth certain information, as of March 11, 2003, with respect to the executive officers of the Registrant.

Name	Age	Position
Charles D. Davidson (1)	53	Chairman of the Board, President, Chief Executive Officer and Director
Alan R. Bullington (2)	51	Vice President, International
Robert K. Burleson (3)	45	Vice President, Business Administration and President, Noble Energy Marketing, Inc.
Susan M. Cunningham (4)	47	Senior Vice President, Exploration
Albert D. Hoppe (5)	58	Senior Vice President, General Counsel and Secretary
James L. McElvany (6)	49	Senior Vice President, Chief Financial Officer and Treasurer
Richard A. Peneguy, Jr. (7)	52	Vice President, Offshore
William A. Poillion, Jr. (8)	53	Senior Vice President, Production and Drilling
Ted A. Price (9)	43	Vice President, Onshore
David L. Stover (10)	45	Vice President, Business Development
Kenneth P. Wiley (11)	50	Vice President, Information Systems

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(1) Charles D. Davidson has served as President and Chief Executive Officer of the Company since October 2000 and Chairman of the Board since April 2001. Prior to October 2000, he served as President and Chief Executive Officer of Vastar Resources, Inc. ("Vastar") from March 1997 to September 2000 (Chairman from April 2000) and was a Vastar Director from March 1994 to September 2000. From September 1993 to March 1997, he served as a Senior Vice President of Vastar. From December 1992 to October 1993, he was Senior Vice President of the Eastern District for ARCO Oil and Gas Company. From 1988 to December 1992, he held various positions with ARCO Alaska, Inc. Mr. Davidson, age 53, joined ARCO in 1972.

(2) Alan R. Bullington was appointed Vice President and General Manager, International Division of Samedan Oil Corporation on January 1, 1998 and on April 24, 2001 was elected a Vice President of the Company. Prior thereto, he served as Manager-International Operations and Exploration and as Manager-International Operations. Prior to his employment with Samedan in 1990, he held various management positions within the exploration and production division of Texas Eastern Transmission Company.

(3) Robert K. Burleson was elected a Vice President of the Company on April 24, 2001 and has been in charge of the Company's Business Administration Department since April 2002. He has also served as President of Noble Gas Marketing, Inc. (now Noble Energy Marketing, Inc.) since June 14, 1995. Prior thereto, he served as Vice President-Marketing for Noble Gas Marketing since its inception in 1994. Previous to his employment

with the Company, he was employed by Reliant Energy as Director of Business Development for its interstate pipeline, Reliant Gas Transmission.

(4) Susan M. Cunningham has served as the Company's Senior Vice President of Exploration since April 2001. In this role, she oversees the Company's worldwide exploration activities. Prior to joining the Company, Ms. Cunningham was Texaco's Vice President of worldwide exploration from April 2000 to March 2001. From 1997 through 1999, she was employed by Statoil, beginning in 1997 as Exploration Manager for deepwater Gulf of Mexico, being appointed a Vice President in 1998 and responsible, in 1999, for Statoil's West Africa exploration efforts.

(5) Albert D. Hoppe has served as Senior Vice President, General Counsel and Secretary of the Company since December 2000. Prior thereto, he served as Vice President, General Counsel and Secretary of Vastar Resources, Inc. from 1994 through 2000. Prior to his Vastar service, he held various executive and management legal positions with Atlantic Richfield Company.

(6) James L. McElvany has served as Senior Vice President, Chief Financial Officer and Treasurer of the Company since July 2002. Prior thereto, he served as Vice President-Finance, Treasurer and Assistant Secretary since July 1999. Prior to July 1999, he had served as Vice President-Controller of the Company since December 1997. Prior thereto, he served as Controller of the Company since December 1983.

(7) Richard A. Peneguy, Jr. was elected a Vice President of the Company on April 24, 2001 and has served as Vice President and General Manager, Offshore Division of Samedan Oil Corporation since February 2002. Prior thereto, he served as Vice President and General Manager, Onshore Division of Samedan since January 2000. Prior thereto, he served as General Manager, Onshore Division of Samedan since January 1, 1991.

(8) William A. Poillion, Jr. was elected a Senior Vice President of the Company on April 24, 2001 and has served as Senior Vice President-Production and Drilling of Samedan Oil Corporation since January 1998. Prior thereto, he served as Vice President-Production and Drilling of Samedan since November 1990. From March 1, 1985 to October 31, 1990, he served as Manager of Offshore Production and Drilling for Samedan.

(9) Ted A. Price was appointed a Vice President of the Company and Division Manager for the Onshore Division on January 29, 2002. Previously, he served as Manager of Onshore Exploration since 1999. Mr. Price joined the Company in 1981 as a geologist.

(10) David L. Stover was elected the Company's Vice President of Business Development on December 16, 2002. Previous to his employment with the Company, he was employed by BP as Vice President, Gulf of Mexico Shelf from September 2000 to August 2002. Prior to joining BP, Mr. Stover was employed by Vastar Resources, Inc. as Area Manager for Gulf of Mexico Shelf from April 1999 to September 2000, and prior thereto, as Area Manager for Oklahoma/Arklatex from January 1994 to April 1999.

(11) Kenneth P. Wiley has served as the Company's Vice President-Information Systems since July 1998. Prior thereto, he served as Manager-Information Systems for Samedan Oil Corporation since November 1994.

Officers serve until the next annual organizational meeting of the Board of Directors or until their successors are chosen and qualified. No officer or executive officer of the Registrant currently has an employment agreement with the Registrant or any of its subsidiaries, although Mr. Davidson had an employment agreement with the Registrant until February 1, 2002. There are no family relationships among any of the Registrant's officers.

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters.

Common Stock. The Registrant's Common Stock, $3.33 1/3 par value ("Common Stock"), is listed and traded on the New York Stock Exchange under the symbol "NBL." The declaration and payment of dividends are at the discretion of the Board of Directors of the Registrant and the amount thereof will depend on the Registrant's results of operations, financial condition, contractual restrictions, cash requirements, future prospects and other factors deemed relevant by the Board of Directors.

Stock Prices and Dividends by Quarters. The following table sets forth, for the periods indicated, the high and low sales price per share of Common Stock on the New York Stock Exchange and quarterly dividends paid per share.

	High	*Low*	*Dividends Per Share*
2002			
First quarter	$40.00	$30.76	$.04
Second quarter	$40.76	$34.70	$.04
Third quarter	$36.34	$26.65	$.04
Fourth quarter	$40.50	$31.55	$.04
2001			
First quarter	$51.09	$39.63	$.04
Second quarter	$45.20	$34.26	$.04
Third quarter	$38.19	$27.50	$.04
Fourth quarter	$40.00	$30.00	$.04

Transfer Agent and Registrar. The transfer agent and registrar for the Common Stock is Wachovia Bank, N.A., NC1153, 1525 West W. T. Harris Blvd., 3C3, Charlotte, North Carolina 28262-1153.

Stockholders' Profile. As of December 31, 2002, the number of holders of record of Common Stock was 1,085. The following chart indicates the common stockholders by category.

December 31, 2002	*Shares Outstanding*
Individuals	602,640
Joint accounts	55,350
Fiduciaries	221,479
Institutions	2,551,728
Nominees	53,922,073
Foreign	9,275
Total-Excluding Treasury Shares	57,362,545

Sales of Unregistered Securities. Prior to January 2002, AMCCO was a 50 percent owned joint venture that owned an indirect 90 percent interest in 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 December 15, 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 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's debt 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. At the same time the Series A-2 Notes were issued, the Company guaranteed the payment of interest on the Series A-2 Notes and issued, in a private placement pursuant to Section 4(2) of the Securities Act, 125,000 shares of its Series B Mandatorily Convertible Preferred Stock (the "Series B Preferred"), par value $1.00 per share to Noble Share Trust, which is a Delaware statutory business trust, in exchange for all of the beneficial ownership interests in the Noble Share Trust.

Noble Share Trust holds the 125,000 shares of Series B Preferred for the benefit of the holders of the Series A-2 Notes. The Series A-2 indenture trustee, and the holders of 25 percent of the outstanding principal amount of the Series A-2 Notes, would have the right to require a public offering of the Series B Preferred to generate proceeds sufficient to repay the Series A-2 Notes, upon the occurrence of certain events ("Trigger Dates"), including (i) defaults under the Indenture governing the Series A-2 Notes, (ii) a default and acceleration of the Company's debt exceeding five percent of the Company's consolidated net tangible assets, and (iii) the simultaneous occurrence of a downgrade of the Company's unsecured senior debt rating to "Ba1" or below by Moody's or "BB+" or below by Standard & Poor's and a decline in the closing price of the Company's common stock for three consecutive trading days to below $17.50. The exercise of this mandatory remarketing right is subject to certain forbearance provisions that would allow the Company the opportunity to obtain funds for the repayment of the Series A-2 Notes by alternative means for a specified period of time.

The terms of the Series B Preferred, including dividend and conversion features, would be reset at the time of the remarketing, based on the recommendation of Credit Suisse First Boston, as Remarketing Agent, as to the terms necessary to generate proceeds to repay the Series A-2 Notes. If the Remarketing Agent is not able to complete a registered public offering of the Series B Preferred, it may under certain circumstances conduct a private placement of such stock. If it were impossible for legal reasons to remarket the Series B Preferred, the Company would be obligated to repay the Series A-2 Notes.

The Series B Preferred stock would be mandatorily convertible into the Company's common stock three years after remarketing (or failed remarketing). Generally, each share of Series B Preferred would then be mandatorily convertible at the "Mandatory Conversion Rate," which is equal to the following number of shares of the Company's common stock:

(a) if the Mandatory Conversion Date Market Price is greater than or equal to the Threshold Appreciation Price, the quotient of (i) $1,000 divided by (ii) the Threshold Appreciation Price;

(b) if the Mandatory Conversion Date Market Price is less than the Threshold Appreciation Price but is greater than the Reset Price, the quotient of $1,000 divided by the Mandatory Conversion Date Market Price; and

(c) if the Mandatory Conversion Date Market Price is less than or equal to the Reset Price, the quotient of $1,000 divided by the Reset Price.

"Mandatory Conversion Date Market Price" means the average closing price per share of the Company's common stock for the 20 consecutive trading days immediately prior to, but not including, the mandatory conversion date.

"Threshold Appreciation Price" means the product of (i) the Reset Price (as the same may be adjusted from time to time) and (ii) 110 percent.

"Reset Price" means the higher of (i) the closing price of a share of the Company's common stock on the Trigger Date or (ii) the quotient (rounded up to the nearest cent) of $125,000,000 divided by the number, as of the Trigger Date, of the authorized but unissued shares of common stock that have not been reserved as of the Trigger Date by the Company's Board of Directors for other purposes.

In addition to the mandatory conversion discussed above, each share of the Series B Preferred is generally convertible, at the option of the holder thereof at any time before the mandatory conversion date, into 36.364 shares of the Company's common stock (the "Optional Conversion Rate"); provided, however, that the Optional Conversion Rate shall adjust, as of the earlier to occur of remarketing or failed remarketing, to the quotient of (i) $1,000 divided by (ii) the Threshold Appreciation Price.

Item 6. Selected Financial Data.

(in thousands, except per share amounts and ratios)	2002	2001	2000	1999	1998
	Year Ended December 31,				
Revenues and Income					
Revenues	$1,443,728	$1,588,690	$1,399,457	$ 918,349	$ 906,787
Net cash provided by operating activities	504,291	635,772	570,334	343,100	382,010
Net income (loss)	17,652	133,575	191,597	49,461	(164,025)
Per Share Data					
Basic earnings (loss) per share	$ .31	$ 2.36	$ 3.42	$ .87	$ (2.88)
Cash dividends	$ .16	$ .16	$ .16	$ .16	$ .16
Year-end stock price	$ 37.55	$ 35.29	$ 46.00	$ 21.44	$ 24.63
Basic weighted average shares outstanding	57,196	56,549	55,999	57,005	56,955
Financial Position (at year end)					
Property, plant and equipment, net:					
Oil and gas mineral interests, equipment and facilities	$2,139,785	$1,953,211	$1,485,123	$1,242,370	$1,429,667
Total assets	2,730,015	2,479,848	1,879,280	1,420,351	1,686,080
Long-term obligations:					
Long-term debt, net of current portion	977,116	837,177	525,494	445,319	745,143
Deferred income taxes	201,939	176,259	117,048	83,075	106,823
Other	69,820	75,629	61,639	53,877	52,868
Shareholders' equity	1,009,386	1,010,198	849,682	683,609	642,080
Ratio of debt-to-book capital	.50	.47	.38	.39	.54
Capital Expenditures					
Oil and gas mineral interests, equipment and facilities	$ 543,967	$ 765,291	$ 502,430	$ 121,077	$ 445,910
Methanol and power projects	57,646	95,716	98,737	89,728	25,131
Other	3,185	1,932	4,430	1,410	2,733
Total capital expenditures	$ 604,798	$ 862,939	$ 605,597	$ 212,215	$ 473,774

For additional information, see "Item 8. Financial Statements and Supplementary Data" of this Form 10-K.

Operating Statistics

	2002	2001	2000	1999	1998
	Year Ended December 31,				
Natural Gas					
Sales (in millions)	$ 392.1	$ 595.4	$ 553.7	$ 365.1	$ 446.0
Production (MMcfpd)	387.6	422.4	406.3	455.1	566.6
Average realized price (per Mcf)	$ 2.92	$ 3.98	$ 3.80	$ 2.26	$ 2.20
Crude Oil					
Sales (in millions)	$ 292.9	$ 255.5	$ 229.6	$ 180.6	$ 160.6
Production (Bopd)	34,037	30,661	25,805	30,003	37,217
Average realized price (per Bbl)	$ 23.98	$ 23.30	$ 24.95	$ 16.81	$ 12.12
Royalty sales (in millions)	$ 15.6	$ 20.9	$ 17.3	$ 14.0	$ 13.1

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. For more information, see "Item 7a. Quantitative and Qualitative Disclosures About Market Risk - Cautionary Statement for Purposes of the Private Securities Litigation Reform Act of 1995 and Other Federal Securities Laws" of this Form 10-K.

CRITICAL ACCOUNTING POLICIES AND PRACTICES

The preparation of the consolidated financial statements requires management of the Company to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. The Company's estimates of crude oil and natural gas reserves are the most significant. All of the reserve data in this Form 10-K are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved natural gas and crude oil reserves. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of crude oil and natural gas that are ultimately recovered.

The Company accounts for its crude oil and natural gas properties under the successful efforts method of accounting. Under this method, costs to acquire mineral interests in crude oil and natural gas properties, to drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Capitalized costs of producing crude oil and natural gas properties are amortized to operations by the unit-of-production method based on proved developed crude oil and natural gas reserves on a property-by-property basis as estimated by Company engineers. Through December 31, 2002, estimated future restoration and abandonment costs are recorded by charges to depreciation, depletion and amortization ("DD&A") expense over the productive lives of the related properties.

The Company generally recognizes revenue when the product is delivered to a third-party purchaser. The Company follows the entitlements method of accounting for its natural gas imbalances. Natural gas imbalances occur when the Company sells more or less natural gas than it is entitled to under its ownership percentage of total natural gas production. Any excess amount received above the Company's share is treated as a liability. If less than the Company's entitlement is received, the underproduction is recorded as a receivable.

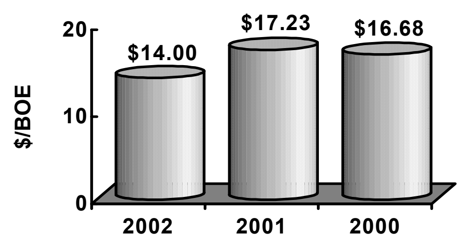
The Company, directly or through its subsidiaries, from time to time, uses various derivative arrangements in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations. Such arrangements include fixed price hedges, costless collars and other contractual arrangements. The Company accounts for its derivative arrangements under Statement of Financial Accounting Standard ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," and has elected to designate its derivative arrangements as cash flow hedges.

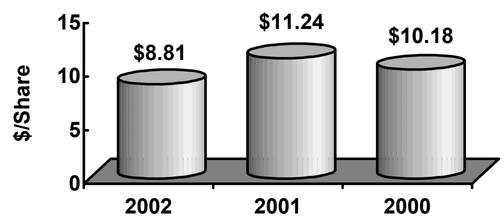
Other significant items subject to estimates and assumptions include the carrying amount of property, plant and equipment; valuation allowances for receivables, inventories and deferred income tax assets; environmental liabilities; valuation of derivative instruments; and assets and obligations related to employee benefits. Actual results could differ from those estimates. Management believes it is necessary to understand the Company's significant accounting policies, "Item 8. Financial Statements and Supplementary Data--Note 1 - Summary of Significant Accounting Policies" of this Form 10-K, in order to understand the Company's financial condition, changes in financial condition and results of operations.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

The Company's net cash provided from operations in 2002 was lower than 2001 due to lower natural gas prices and decreased gas production volumes, offset partially by higher oil prices and increased oil production volumes. Net cash from operating activities per BOE of production and per share are shown in the charts below.





The crude oil price received by the Company in 2002 increased three percent from 2001 and the natural gas price received by the Company decreased 27 percent in 2002 from the price received in 2001. In 2001, the Company's crude oil price decreased nine percent and the natural gas price increased five percent compared to 2000.

Prior to January 2002, AMCCO was a 50 percent owned joint venture that owned an indirect 90 percent interest in 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 December 15, 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 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's debt 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 total costs of the plant and supporting facilities as of December 31, 2002 were $417 million, with the Company responsible for $208.5 million. During 2002, the Company recorded costs of $7 million toward the project.

During 2002, $544 million was spent on acquisition, exploration and development projects, $7 million on the methanol project, $51 million on the Machala power project in Ecuador and $3 million for various other projects for total expenditures of $605 million. The 2003 capital expenditures budget is approximately $510 million.

The Company's current ratio (current assets divided by current liabilities) was .66:1 at December 31, 2002, compared with .92:1 at December 31, 2001. The decrease in the current ratio was due to a $57.8 million decrease in cash and short-term investments coupled with an $81.8 million increase in accounts payable.

Financing

The Company's total long-term debt, net of unamortized discount, at December 31, 2002, was $977 million compared to $837 million at December 31, 2001. If the $125 million AMCCO debt had been included, the total long-term debt would have been $962 million at December 31, 2001. The ratio of debt-to-book capital (defined as the Company's total debt plus its equity) was 50 percent at December 31, 2002, compared with 47 percent at December 31, 2001.

(in thousands)	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1 to 3 Years	4 to 5 Years	After 5 Years
Long-term debt	$ 1,025,246	$ 41,919	$ 153,327	$ 380,000	$ 450,000
Drilling obligations	118,211	116,411	1,800		
Total contractual cash obligations	$ 1,143,457	$ 158,330	$ 155,127	$ 380,000	$ 450,000

The Company's long-term debt, net of current portion, is comprised of:

- $250 million of 8% Senior Notes Due 2027
- $100 million of 7 1/4% Notes Due 2097
- $100 million of 7 1/4% Notes Due 2023
- $380 million on the $400 million credit facility based upon a Eurodollar rate plus a range of 60 to 145 basis points depending upon the percentage of utilization and credit rating, maturing in 2006. The interest rate at December 31, 2002 was 2.47 percent. The interest rate at December 31, 2001 was 3.0 percent.
- $125 million of 8.95% Series A-2 Notes on the AMCCO debt, payable in 2004. There was no AMCCO debt on the Company's balance sheet at December 31, 2001.
- $20.4 million on the Israel debt based upon the London Interbank Offering Rate ("LIBOR") plus 75 basis points, payable in 2004. The interest rate at December 31, 2002 was 2.18 percent. There was no outstanding Israel debt at December 31, 2001.
- $7.9 million of the 6.25% Aspect acquisition note, payable in 2004
- ($6.2) million unamortized discount

The Company entered into a new $400 million five-year credit agreement on November 30, 2001 with certain commercial lending institutions 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 60 to 145 basis points depending upon the percentage of utilization and credit rating. At December 31, 2002, there was $380 million borrowed against this credit agreement, which has a maturity date of November 30, 2006. For more information, see "Item 8. Financial Statements and Supplementary Data--Note 3 - Debt" of this Form 10-K.

The Company also entered into a new $200 million 364-day credit agreement on November 27, 2002 with certain commercial lending institutions 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 December 31, 2002, there were no amounts outstanding under this credit agreement. The agreement has a maturity date of November 26, 2003 for the revolving commitment and a maturity date of November 25, 2004 for the term commitment that includes any balance remaining after the revolving commitment matures. For more information, see "Item 8. Financial Statements and Supplementary Data--Note 3 - Debt" of this Form 10-K.

Financial covenants on both the $400 million and $200 million credit facilities include the following: (a) the ratio of Earnings Before Interest, Taxes, Depreciation and Exploration Expense ("EBITDAX") to total interest expense for any consecutive period of four fiscal quarters ending on the last day of a fiscal quarter may not be less than 4.0 to 1.0; (b) the total debt to capitalization ratio, expressed as a percentage, may not exceed 60 percent at any time; and (c) the total asset value of the Company's restricted subsidiaries may not be less than $800 million at any time.

The Company had no short-term borrowings outstanding on December 31, 2002. The Company had a $25 million short-term note payable outstanding December 31, 2001, which was repaid January 28, 2002. The note was an uncommitted facility with an interest rate of 3.25 percent for the period December 28, 2001 to January 28, 2002.

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 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's debt 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.

Other

The Company has paid quarterly cash dividends of $.04 per share since 1989 and currently anticipates it will continue to pay quarterly dividends of $.04 per share.

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 program was scheduled to mature in January 2003 but has been extended to January 2004. Under the provisions of the agreement with the bank, 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 (to $16.77 per share) 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 December 31, 2002, the fair value of the Company's obligation under the contract would be an obligation to pay approximately $36.1 million to the bank (and hold the shares as treasury stock), or the bank would return 81,946 shares of Company stock to the Company, or the bank would pay $3.1 million to the Company.

The Company has sold a number of non-strategic crude oil and natural gas properties over the past three years. Total amounts of crude oil and natural gas reserves associated with the 2002 and 2000 dispositions were .7 MMBbls of oil and 20.3 Bcf of gas and 1.2 MMBbls of oil and 4.8 Bcf of gas, respectively. There were no significant sales of oil or gas properties in 2001. The Company believes the disposition of non-strategic properties furthers the goal of concentrating its efforts on strategic properties.

During 2002, the Company paid $7 million related to certain operating contingencies that had previously been accrued.

The Financial Accounting Standards Board ("FASB") issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," in June 1998. The Statement established 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 shareholders' equity as other comprehensive income 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 statement of operations, and requires that a company formally document, designate and assess the effectiveness of transactions that receive hedge accounting. The Company adopted SFAS No. 133 effective January 1, 2001. The adoption of this statement did not have a material impact on the Company's results of operations or financial position.

RESULTS OF OPERATIONS

Net Income and Revenues

The Company's net income for 2002 was $17.7 million, a decrease of $115.9 million from 2001. The decrease was due primarily to a $208.3 million decrease in natural gas sales, offset by a $37.1 million increase in crude oil sales. The decrease in net income for 2001 compared to 2000 was due to a $61.2 million increase in dry hole expense, offset by a $3.8 million decrease in abandoned asset expense.

Natural Gas Information

Natural gas revenues decreased 34 percent in 2002 due to a 27 percent decrease in the average natural gas price coupled with an eight percent decrease in natural gas production. In the United States, natural gas production decreased 13 percent due to reduced drilling activity, natural decline rates for properties in the Gulf of Mexico and the onshore Gulf Coast region, as well as temporary shut-ins related to Hurricanes Isidore and Lili, coupled with a 25 percent decrease in the average natural gas price. In the North Sea, natural gas revenues decreased 15 percent due to an 11 percent decrease in the average natural gas price coupled with a five percent decrease in natural gas production. In Equatorial Guinea, natural gas revenues increased 39 percent due to the full year of operations of the methanol plant.

Natural gas revenues for 2001 increased eight percent due to a four percent increase in natural gas production coupled with a five percent increase in the average natural gas price compared to 2000. The methanol plant in Equatorial Guinea began operations on May 2, 2001, which accounted for the increased natural gas production compared to 2000.

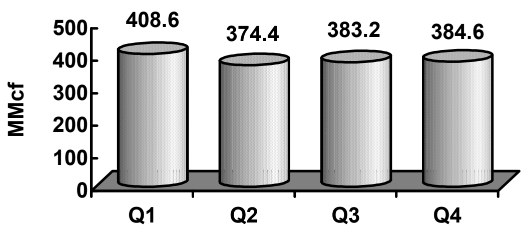
The table below depicts average daily natural gas production in Mcf by area for the last three years.

	2002	*2001*	*2000*
United States	327,451	378,475	378,101
North Sea	16,991	17,830	23,676
Equatorial Guinea	34,382	24,488	2,572
Other International	8,799	1,651	1,970
Total	387,623	422,444	406,319

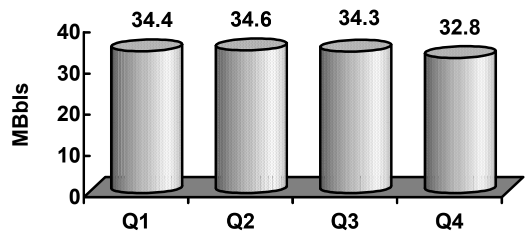
Natural gas production during 2002 ranged from a low of 351.8 MMcfpd in May, to a high of 424.3 MMcfpd in January. Natural gas accounted for 57 percent of the Company's total natural gas and crude oil revenues in 2002.

2002 Daily Production by Quarter

Natural Gas



Crude Oil



Crude Oil Information

Crude oil revenues increased 14 percent during 2002 due to an 11 percent increase in production coupled with a three percent increase in the average crude oil price. In the North Sea, crude oil revenues increased 80 percent due to a full year of production from the Hanze field, the commencement of production from the Hannay field in March 2002 and an eight percent increase in the average crude oil price. In Equatorial Guinea, crude oil revenues increased 18 percent due to a 14 percent increase in production from the Alba field, coupled with a four percent increase in the average crude oil price.

Crude oil revenues increased 11 percent in 2001, compared to 2000, due to a 19 percent increase in production offset by a seven percent decline in the average price received for 2001. In the North Sea, crude oil revenues increased 136 percent due to the commencement of production from the Hanze field in August 2001, offset by a 10 percent decrease in the average crude oil price. In Equatorial Guinea, crude oil revenues increased 52 percent due to an 85 percent increase in production from the Alba field, offset by a 17 percent decline in the average price.

The table below depicts average daily crude oil production in Bbls by area for the last three years.

	2002	*2001*	*2000*
United States	18,110	18,614	19,019
North Sea	7,847	4,688	1,787
Equatorial Guinea	5,259	4,620	2,497
Other International	2,821	2,739	2,502
Total	34,037	30,661	25,805

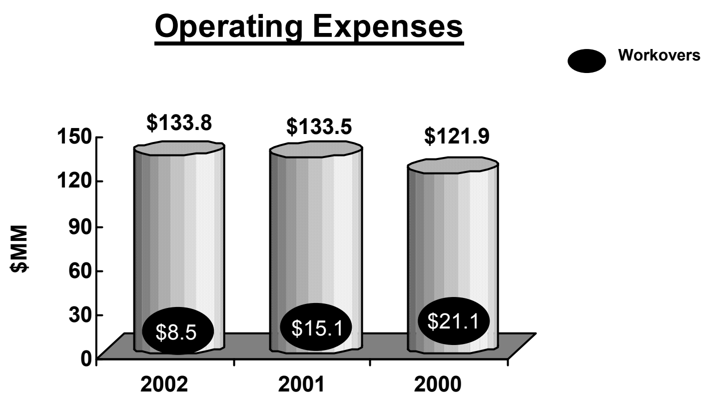
Crude oil production during 2002 ranged from a low of 31,060 Bopd in July, to a high of 36,381 Bopd in April. Crude oil accounted for 43 percent of the Company's total natural gas and crude oil revenues in 2002.

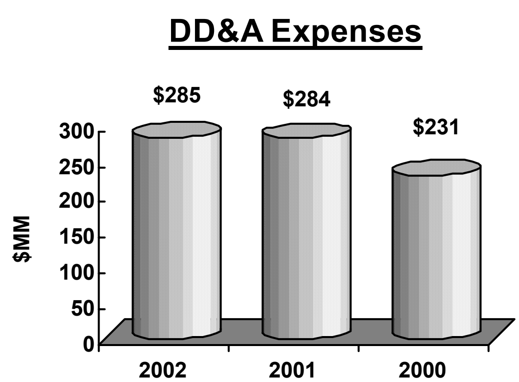
Derivatives and Hedging Activities

The Company, directly or 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 and believes that losses from nonperformance are unlikely to occur. Hedging gains and losses related to the Company's crude oil and natural gas production are recorded in crude oil and natural gas sales and royalties. For more information, see "Item 7a. Quantitative and Qualitative Disclosures About Market Risk" of this Form 10-K.

Costs and Expenses

Crude oil and natural gas operations expense, consisting of lease operating expense, workover expenses, production taxes and other related lifting costs, was flat overall, in absolute dollars, in 2002 compared to 2001. In the North Sea, operations expense increased 78 percent due to a full year of production operations from the Hanze field and the commencement of operations from the Hannay field in March 2002. In Equatorial Guinea, operations expense increased 45 percent due to the increased production from the Alba field. Domestic operations expense decreased in absolute terms during 2002 offsetting the international increases. Crude oil and natural gas operations expense increased 10 percent overall in 2001 from 2000. In the North Sea, operations expense increased 16 percent due to the commencement of operations of the Hanze field in August 2001. In Equatorial Guinea, operations expense increased 61 percent due to the commencement of natural gas deliveries to the methanol plant in May 2001. Included in operations expense were workover costs of $8.5 million, $15.1 million and $21.1 million for 2002, 2001 and 2000, respectively. The workovers increased operations expense in such periods by $.04, $.07 and $.10 per Mcfe, respectively.





In 2002, DD&A expense increased slightly compared to 2001. In the North Sea, DD&A expense increased 71 percent due to a full year's production of the Hanze field. In Equatorial Guinea, DD&A expense increased 50 percent due to the results of the field expansion, which included a full year of natural gas sales to the methanol plant. The unit rate of DD&A per BOE was $7.92 in 2002.

In 2001, DD&A expense increased 23 percent overall compared to 2000. In the United States, DD&A expense increased 22 percent due to increased development costs incurred in the Gulf of Mexico to stabilize production volumes. In the North Sea, DD&A expense increased 34 percent due to the commencement of production from the Hanze field in August 2001. In Equatorial Guinea, DD&A expense increased 186 percent due to the commencement of natural gas sales to the methanol plant in May 2001. The unit rate of DD&A per BOE was $7.70 in 2001.

Through December 31, 2002, the Company provided for the cost of future liabilities related to restoration and dismantlement costs for offshore facilities. This provision is based on the Company's best estimate of such costs to be incurred in future years based on information from the Company's engineers. These estimated costs were provided through charging DD&A expense using a ratio of production divided by reserves multiplied by the estimated costs to dismantle and restore. The Company adopted SFAS No. 143 on January 1, 2003 and will recognize, as the fair value of asset retirement obligations, $99.7 million related to the United States and $10.0 million related to the North Sea. The Company's accumulated provision for future dismantlement and restoration cost was $84.1 million at

December 31, 2002, $80.0 million at December 31, 2001 and $79.7 million at December 31, 2000. The Company has not determined the cumulative effect of adoption of this standard. Total estimated future dismantlement and restoration costs of $206.6 million, which consists of $188.7 million for the United States and $17.9 million for the North Sea, are included in future production and development costs for purposes of estimating the future net revenues relating to the Company's proved reserves. For more information, see "Item 8. Financial Statements and Supplementary Data-- Note 1 - Summary of Significant Accounting Policies" of this Form 10-K.

Crude oil and natural gas exploration expense consists of dry hole expense, unproved lease amortization, seismic and other miscellaneous exploration expense, including lease rentals and exploration staff. The table below depicts the exploration expense by area for the last three years.

(in thousands)	*2002*	*2001*	*2000*
United States			
Dry hole expense	$ 64,449	$ 54,810	$ 37,281
Unproved lease amortization	19,426	15,112	15,675
Seismic	14,282	13,328	17,794
Other	22,538	17,242	9,617
United States Total Exploration Expense	$ 120,695	$ 100,492	$ 80,367
North Sea			
Dry hole expense	$ 544	$ 28,992	$ 17
Unproved lease amortization	178	1,725	
Seismic	827	2,209	239
Other	3,661	2,024	1,140
North Sea Total Exploration Expense	$ 5,210	$ 34,950	$ 1,396
Other International including Israel and Equatorial Guinea			
Dry hole expense	$ 16,403	$ 15,882	$ 1,165
Unproved lease amortization	1,650	376	400
Seismic	5,383	70	705
Other	1,360	326	835
Other International Total Exploration Expense	$ 24,796	$ 16,654	$ 3,105
Total Exploration Expense	$ 150,701	$ 152,096	$ 84,868

Impairment of Operating Assets

Developed crude oil and natural gas properties and other long-lived assets are assessed whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. The Company performs this review of recoverability by estimating future cash flows. If the sum of the expected future cash flows is less than the carrying amount of the asset, an impairment is recognized based on the fair value of the assets as determined using the expected present value of future net cash flows. The Company recorded no operating asset impairments during 2002, 2001 or 2000. Individually significant unproved crude oil and natural gas properties are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance.

Selling, General and Administrative Expenses ("SG&A")

SG&A expenses increased $3.5 million in 2002 compared to 2001 and decreased $3.1 million in 2001 compared to 2000. The increase in SG&A expenses for 2002 is due to increased salary and legal expense, as well as increased costs associated with the Company's international expansion. The decrease in 2001 compared to 2000 reflects the Company's effort to reduce SG&A through efficiencies and other reduction measures.

Gathering, Marketing and Processing

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

The gathering, marketing and processing revenues less expenses for NEMI are reflected in the table below.

(in thousands)	*2002*		*2001*		*2000*	
(amounts include inter-company eliminations)	Crude Oil	Natural Gas	Crude Oil	Natural Gas	Crude Oil	Natural Gas
Revenues	$ 88,377	$ 625,714	$ 75,550	$ 645,400	$ 91,204	$ 498,729
Expenses						
Cost of goods sold	61,553	588,022	49,191	607,170	63,005	464,600
Transportation	20,323	28,284	19,739	27,779	19,455	24,014
General and administrative	802	3,857	199	3,176	190	3,002
Total Expenses	$ 82,678	$ 620,163	$ 69,129	$ 638,125	$ 82,650	$ 491,616
Gross Margin	$ 5,699	$ 5,551	$ 6,421	$ 7,275	$ 8,554	$ 7,113

The margins for natural gas on a per MMBTU basis were $.035 for 2002 and 2001 and $.027 for 2000. The increase in natural gas margin on a per MMBTU basis for 2001 compared to 2000 was due to the improvement in natural gas prices. The margins for crude oil on a per Bbl basis were $.84 for 2002, $.95 for 2001 and $1.28 for 2000. The decrease in crude oil margin for 2002 compared to 2001 was due to increased general and administrative expenses coupled with higher transportation expense. The decrease in crude oil margin for 2001 compared to 2000 was due to lower crude oil prices.

Income Taxes

Income tax expense decreased to $25 million in 2002 from $91 million in 2001, primarily from the decrease in income. However, the effective income tax rate increased to 59 percent in 2002 from 41 percent in 2001. During 2002, more of the Company's income was from international operations. Some of the countries in which the international operations were conducted have a higher statutory income tax rate than the United States. To a lesser extent, also impacting the effective rate in 2002 was the lower income level.

FUTURE TRENDS

The Company expects crude oil and natural gas production to increase in 2003 and 2004 compared to 2002. The increased production in 2003 is expected primarily from the phase 2A expansion of the Alba field in Equatorial Guinea, the startup of production from the Mari-B field, offshore Israel, production from the CDX block in China and a full year of production in Ecuador. The increase in 2004 is expected primarily from the continued expansion of markets in Israel and the phase 2B expansion of the LPG plant in Equatorial Guinea.

The Company recently set its 2003 capital expenditures budget at approximately $510 million. Such expenditures are planned to be funded principally 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 available lines of credit and other borrowing opportunities.

SFAS No. 148, “Accounting for Stock-Based Compensation,” was issued in December 2002. This statement amends SFAS No. 123, “Accounting for Stock-Based Compensation,” to provide for alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation. It also amends the disclosure provisions of that statement to require prominent disclosure about the effects on reported net income of an entity’s accounting policy decisions with respect to stock-based employee compensation.

The Company currently accounts for stock-based employee compensation plans under the recognition and measurement principles of the Accounting Principles Board (“APB”) Opinion No. 25, “Accounting for Stock Issued to Employees.” The Company has not determined if it will adopt the fair value provisions of SFAS No. 123.

In June 2002, the Emerging Issues Task Force (“EITF”) reached a consensus on certain issues contained in Topic 02-03, “Recognition and Reporting of Gains and Losses on Energy Trading Contracts” under EITF Issue No. 98-10, “Accounting for Contracts Involved in Energy Trading and Risk Management Activities.” While the Company does not engage in material energy trading activities, the EITF has expanded its definition of energy trading activities to include the marketing activities in which the Company is engaged. As of January 1, 2003, the Company will present its gathering, marketing and processing activities in the statement of operations for all periods on a net rather than a gross basis. The change will significantly decrease reported marketing sales and purchases, but will have no effect on operating income or cash flow.

Management believes that the Company is well positioned with its balanced reserves of crude oil and natural gas and downstream projects. The uncertainty of commodity prices continues to affect the crude oil, natural gas and methanol industries. The Company cannot predict the extent to which its revenues will be affected by inflation, government regulation or changing prices.

Item 7a. 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 crude oil and natural gas reserves to take advantage of future price increases that may occur. However, the uncertainty of crude oil and natural gas prices continues to impact the oil and gas industry. Due to the volatility of crude oil and natural gas prices, the Company, from time to time, has used derivative hedging instruments and may do so in the future as a means of managing its exposure to price changes.

During 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. The table below depicts the various transactions for 2002.

Natural Gas		Crude Oil	
Hedge MMBTUpd	170,274	Hedge Bpd	5,247
Floor price range	\$2.00 - \$3.50	Floor price range	\$23.00 - \$24.00
Ceiling price range	\$2.45 - \$5.10	Ceiling price range	\$29.30 - \$30.10
Percent of daily production	44%	Percent of daily production	15%
Gain (loss) per Mcf	\$.03	Gain (loss) per Bbl	\$0

As of December 31, 2002, the Company had entered into costless collars related to its natural gas and crude oil production to support the Company's investment program as follows:

	Natural Gas		Crude Oil	
Production Period	MMBTU Per Day	Price Per MMBTU Floor - Ceiling	Bbls Per Day	Price Per Bbl Floor - Ceiling
1Q 2003	185,000	$3.87 - $4.82	15,000	$23.00 - $28.63
2Q 2003	185,000	$3.43 - $4.57	15,000	$23.00 - $28.63
3Q 2003	185,000	$3.43 - $4.60	10,000	$23.00 - $27.95
4Q 2003	185,000	$3.43 - $4.84	10,000	$23.00 - $27.95

The contracts entitle the Company (floating price payor) to receive settlement from the counterparty (fixed price payor) for each calculation period in amounts, if any, by which the settlement price for the last scheduled NYMEX trading day applicable for each calculation period is less than the floor price. The Company would pay the counterparty if the settlement price for the last scheduled NYMEX trading day applicable for each calculation period were 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 calculation period. 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 calculation period.

During 2001, the Company had natural gas costless collars for the fourth quarter of 2001 for 50,000 MMBTU of natural gas per day, with a floor price of $3.25 per MMBTU and a ceiling price of $4.60 per MMBTU. The net effect of this fourth quarter 2001 hedge was a $.02 per Mcf increase in the average natural gas price for the year 2001. Of the 50,000 MMBTU per day of costless collars, 25,000 MMBTU per day were terminated early, at a gain. As a result, the Company recognized an additional $.70 per MMBTU on the 25,000 MMBTU of natural gas per day in 2001.

NEMI, from time to time, employs hedging arrangements in connection with its purchases and sales of production. While most of NEMI's purchases are made for an index-based price, NEMI'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, NEMI may convert a fixed or NYMEX sale to an index-based sales price (such as by purchasing an index-based futures contract obligating NEMI for delivery of production). Due to the size of such transactions and certain restraints imposed by contract and by Company guidelines, as of December 31, 2002, the Company had no material market risk exposure from NEMI's hedging activity.

The Company has a $400 million credit agreement that 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 60 to 145 basis points depending upon the percentage of utilization and credit rating. At December 31, 2002, there was $380 million borrowed against this credit agreement with an interest rate of 2.47 percent and a maturity date of November 30, 2006. A ten percent change in the December 31, 2002 interest rate on this $380 million would result in a change in interest expense of $937,080. All other significant 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. For more information, see "Item 8. Financial Statements and Supplementary Data--Note 3 - Debt" of this Form 10-K.

The Company does not enter into 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 income on the statement of operations. 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.

Cautionary Statement for Purposes of the Private Securities Litigation Reform Act of 1995 and Other Federal Securities Laws

General. Noble Energy is including the following discussion to generally inform its existing and potential security holders 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 management's behalf make forward-looking statements to inform existing and potential security holders about the Company. These statements may include, but are not limited to, projections and estimates concerning the timing and success of specific projects and the Company's future: (1) income, (2) crude oil and natural gas production, (3) crude oil and natural 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 the Company will specifically describe a statement as being a forward-looking statement. In addition, except for the historical information contained in this Form 10-K, the matters discussed in this Form 10-K 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.

Noble Energy believes the factors discussed below are important factors that could cause actual results to differ materially from those expressed in any forward-looking statement made herein or elsewhere by the Company or on its 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. Noble Energy does not intend to update its description of important factors each time a potential important factor arises. The Company advises its 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 such forward-looking statements are qualified in their entirety by this cautionary statement.

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 supply and demand fundamentals and changes in the political, regulatory and economic climates and other factors that affect commodities markets generally and are outside of Noble Energy's control. Some of Noble Energy's 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. The Company expects its assumptions may change over time and that actual prices in the future may differ from our estimates. Any substantial or extended change in the actual prices of natural gas and/or crude oil could have a material effect on: (1) the Company's financial position and results of operations, (2) the quantities of natural gas and crude oil reserves that the Company can economically produce, (3) the quantity of estimated proved reserves that may be attributed to its properties, and (4) the Company's ability to fund its capital program.

Production Rates and Reserve Replacement. Projecting future rates of crude oil and natural gas production is inherently imprecise. Producing crude oil and natural gas reservoirs generally have declining production rates. Production rates depend on a number of factors, including geological, geophysical and engineering issues, weather, production curtailments or restrictions, prices for natural gas and crude oil, available transportation capacity, market demand and the political, economic and regulatory climates. Another factor affecting production rates is Noble Energy's 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, the Company's 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, Noble Energy's finding and development costs may not justify the use of resources to explore for and develop such reserves.

Reserve Estimates. Noble Energy's forward-looking statements are predicated, in part, on the Company's estimates of its crude oil and natural gas reserves. All of the reserve data in this Form 10-K or otherwise made by or on behalf of the Company are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved natural gas and crude oil reserves. Projecting future rates of production and timing of future development expenditures is also inexact. Many factors beyond the Company's 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, estimates made by different engineers may 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 may be different from the quantities of crude oil and natural gas that are ultimately recovered.

Laws and Regulations. Noble Energy's forward-looking statements are generally based on the assumption that the legal and regulatory environments will remain stable. Changes in the legal and/or regulatory environments could have a material effect on the Company's future results of operations and financial condition. Noble Energy's ability to economically produce and sell crude oil, natural gas, methanol and power is affected 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) crude oil and natural gas production, (2) taxes applicable to the Company and/or its production, (3) the amount of crude oil and natural gas available for sale, (4) the availability of adequate pipeline and other transportation and processing facilities, and (5) the marketing of competitive fuels. The Company's 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. Noble Energy's forward-looking statements are generally based upon the expectation that the Company will not be required, in the near future, to expend cash to comply with environmental laws and regulations that are material in relation to its total capital expenditures program. However, inasmuch as such laws and regulations are frequently changed, the Company is unable to accurately predict the ultimate financial impact of compliance.

Drilling and Operating Risks. Noble Energy's drilling operations are subject to various risks common in the industry, including cratering, explosions, fires and uncontrollable flows of crude oil, natural gas or well fluids. In addition, a substantial amount of the Company's 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. 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 industry is intense. Noble Energy actively competes for reserve acquisitions and exploration leases and licenses, for the labor and equipment required to operate and develop crude oil and natural gas properties and in the gathering and marketing of natural gas, crude oil, methanol and power. The Company's competitors include the major integrated oil companies, independent crude oil and natural 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, many of whom have greater financial resources than the Company.

Noble Energy believes that the location of its properties, its expertise in exploration, drilling and production operations, the experience of its management and the efforts and expertise of its marketing units generally enable it to compete effectively. In making projections with respect to numerous aspects of the Company's business, Noble Energy generally assumes that there will be no material adverse change in competitive conditions.

Item 8. Financial Statements and Supplementary Data.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

All other financial statement schedules have been omitted because the required information is not present or is not present in amounts sufficient to require submission of the schedule or because the information required is included in the financial statements, including the notes thereto.

Independent Auditor's Report

To the Shareholders and Board of Directors of Noble Energy, Inc.:

We have audited the accompanying consolidated balance sheet of Noble Energy, Inc. (a Delaware corporation) and subsidiaries as of December 31, 2002 and the related consolidated statements of operations, shareholders' equity and other comprehensive income, and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit. The financial statements of the Company as of December 31, 2001 and 2000, and for the two years then ended, were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those financial statements dated January 24, 2002.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Noble Energy, Inc. and subsidiaries as of December 31, 2002 and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed above, other auditors who have ceased operations audited the 2001 and 2000 financial statements of Noble Energy, Inc. As described in "Note 11 - Geographical Data," the Company changed the composition of its reportable segments in 2002, and the amounts in the 2001 and 2000 financial statements relating to reportable segments have been restated to conform to the 2002 composition of reportable segments. We audited the adjustments that were applied to restate the disclosures for reportable segments reflected in the 2001 and 2000 financial statements. In our opinion, such adjustments are appropriate and have been properly applied. However, we were not engaged to audit, review or apply any procedures to the 2001 and 2000 financial statements of Noble Energy, Inc. other than with respect to such adjustments and, accordingly, we do not express an opinion or any other form of assurance on the 2001 and 2000 financial statements taken as a whole.

KPMG LLP

Houston, Texas
February 21, 2003

1. **This report is a copy of a previously issued report (see page 32 of the Company's Annual Report for December 31, 2001 on Form 10-K).**

2. **The predecessor auditor has not reissued this report.**

3. **The predecessor auditor's report was issued prior to the restatement referenced in the last paragraph of the February 21, 2003 Independent Auditor's Report by KPMG LLP on page 37 of this Form 10-K.**

Report of Independent Public Accountants

To the Shareholders and Board of Directors of Noble Affiliates, Inc.:

We have audited the accompanying consolidated balance sheet of Noble Affiliates, Inc. (a Delaware corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of operations, shareholders' equity and other comprehensive income and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Noble Affiliates, Inc. and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Oklahoma City, Oklahoma
January 24, 2002

CONSOLIDATED BALANCE SHEETS

NOBLE ENERGY, INC. AND SUBSIDIARIES

(in thousands, except share amounts)	*December 31,* 2002	2001
ASSETS		
Current Assets:		
Cash and short-term investments	$ 15,442	$ 73,237
Accounts receivable - trade	232,924	182,979
Oil and gas hedges receivable	10,271	33,424
Materials and supplies inventories	10,663	10,828
Other current assets	41,074	51,103
Total current assets	310,374	351,571
Property, Plant and Equipment, at Cost:		
Oil and gas mineral interests, equipment and facilities (successful efforts method of accounting)	4,285,508	3,929,226
Other	48,507	45,528
	4,334,015	3,974,754
Accumulated depreciation, depletion and amortization	(2,194,230)	(2,021,543)
Total property, plant and equipment, net	2,139,785	1,953,211
Investment in Unconsolidated Subsidiary, at Cost	234,668	117,735
Other Assets	45,188	57,331
Total Assets	$ 2,730,015	$ 2,479,848
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable - trade	$ 351,856	$ 270,091
Short-term note payable		25,000
Current installments of long-term debt	41,919	19,507
Oil and gas hedges payable	32,285	25,363
Other current liabilities	36,159	40,624
Income taxes - current	9,535	
Total current liabilities	471,754	380,585
Deferred Income Taxes	201,939	176,259
Other Deferred Credits and Noncurrent Liabilities	69,820	75,629
Long-term Debt	977,116	837,177
Shareholders' Equity:		
Preferred stock - par value $1.00; 4,000,000 shares authorized, none issued		
Common stock - par value $3.33 1/3; 100,000,000 shares authorized; 59,868,067 and 59,511,323 shares issued in 2002 and 2001, respectively	199,558	198,369
Capital in excess of par value	405,271	396,104
Accumulated other comprehensive income (loss)	(14,603)	5,070
Retained earnings	458,490	449,985
	1,048,716	1,049,528
Less common stock in treasury at cost (December 31, 2002 and 2001, 2,505,522 shares)	(39,330)	(39,330)
Total shareholders' equity	1,009,386	1,010,198
Total Liabilities and Shareholders' Equity	$ 2,730,015	$ 2,479,848

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF OPERATIONS
NOBLE ENERGY, INC. AND SUBSIDIARIES

	Year ended December 31,		
(in thousands, except per share amounts)	*2002*	*2001*	*2000*
Revenues:			
Oil and gas sales and royalties	$ 700,602	$ 871,812	$ 800,594
Gathering, marketing and processing	714,091	721,000	589,933
Electricity sales	18,257		
Income (loss) from investment in unconsolidated subsidiary	9,532	(5,075)	1,489
Other income	1,246	953	7,441
Total Revenues	1,443,728	1,588,690	1,399,457
Costs and Expenses:			
Oil and gas operations	133,826	133,549	121,866
Transportation	16,441	16,012	9,241
Oil and gas exploration	150,701	152,096	84,868
Gathering, marketing and processing	703,556	708,292	574,266
Electricity generation	15,946		
Depreciation, depletion and amortization	285,286	284,016	230,800
Selling, general and administrative	47,664	44,164	47,291
Interest	64,040	41,904	37,968
Interest capitalized	(16,331)	(15,953)	(6,326)
Total Costs and Expenses	1,401,129	1,364,080	1,099,974
Income Before Taxes	42,599	224,610	299,483
Income Tax Provision:			
Current	7,625	31,595	74,616
Deferred	17,322	59,440	33,270
Total Tax Provision	24,947	91,035	107,886
Net Income	$ 17,652	$ 133,575	$ 191,597
Basic Earnings Per Share	$ 0.31	$ 2.36	$ 3.42
Diluted Earnings Per Share	$ 0.31	$ 2.33	$ 3.38
Weighted Average Shares Outstanding:			
Basic	57,196	56,549	55,999
Diluted	57,763	57,303	56,755

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

NOBLE ENERGY, INC. AND SUBSIDIARIES

	Year ended December 31,		
(in thousands)	*2002*	*2001*	*2000*
Cash Flows from Operating Activities:			
Net income	$ 17,652	$ 133,575	$ 191,597
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	285,286	284,016	230,800
Depreciation, depletion and amortization - electricity generation	8,458		
Dry hole expense	81,396	99,684	38,463
Amortization of unproved leasehold costs, net	21,254	17,213	16,075
(Gain) loss on disposal of assets	(106)	(2,098)	(3,799)
Noncurrent deferred income taxes	18,192	59,212	33,973
(Income) loss from unconsolidated subsidiary	(9,532)	5,075	(1,489)
Dividends received from unconsolidated subsidiary	17,696		
Increase (decrease) in other deferred credits	(5,810)	13,990	7,762
(Increase) decrease in other	10,942	(2,224)	(3,747)
Changes in operating assets and liabilities, not including cash:			
(Increase) decrease in accounts receivable	(49,945)	57,973	(137,049)
(Increase) decrease in other current assets	21,972	(64,951)	3,557
Increase (decrease) in accounts payable	81,764	(17,960)	198,871
Increase (decrease) in other current liabilities	5,072	52,267	(4,680)
Net Cash Provided by Operating Activities	504,291	635,772	570,334
Cash Flows from Investing Activities:			
Capital expenditures	(595,739)	(738,706)	(536,901)
Investment in unconsolidated subsidiary	(7,652)	(48,651)	(57,045)
Proceeds from sale of property, plant and equipment	20,363	1,434	12,608
Distribution from unconsolidated subsidiary	5,500		
Aspect acquisition		(107,078)	
Cash obtained in acquisition		9,286	
Net Cash Used in Investing Activities	(577,528)	(883,715)	(581,338)
Cash Flows from Financing Activities:			
Exercise of stock options	10,356	16,675	13,717
Cash dividends paid	(9,147)	(9,042)	(8,958)
Proceeds from bank debt	158,669	675,000	137,000
Repayment of bank debt	(124,929)	(375,000)	(57,000)
Repayment of notes payable - unconsolidated subsidiary			(23,245)
Repayment of note payable obtained in Aspect acquisition	(19,507)	(9,605)	
Purchase of treasury stock			(30,283)
Net Cash Provided by Financing Activities	15,442	298,028	31,231
Increase (Decrease) in Cash and Short-term Cash Investments	(57,795)	50,085	20,227
Cash and Short-term Cash Investments at Beginning of Year	73,237	23,152	2,925
Cash and Short-term Cash Investments at End of Year	$ 15,442	$ 73,237	$ 23,152

Supplemental Disclosures of Cash Flow Information:			
Cash paid during the year for:			
Interest (net of amount capitalized)	$ 26,321	$ 26,590	$ 32,976
Income taxes paid (refunded)	$ (40,394)	$ 66,131	$ 56,890
Non-cash financing and investing activities:			
Issuance of treasury stock for acquisition		$ 14,238	
Debt assumed in acquisition		$ 40,043	
Consolidation of AMCCO's debt (net of discount)	$ 122,945		

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND OTHER COMPREHENSIVE INCOME

NOBLE ENERGY, INC. AND SUBSIDIARIES

(in thousands)	*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*
December 31, 1999		$195,231	$360,983	$142,813		$(15,418)	$683,609
Net Income				191,597			191,597
Purchase of treasury stock						(30,283)	(30,283)
Exercise of stock options		1,441	12,276				13,717
Cash dividends ($.16 per share)				(8,958)			(8,958)
December 31, 2000		$196,672	$373,259	$325,452		$(45,701)	$849,682
Net Income	$ 133,575			133,575			133,575
Hedge derivatives marked to market	5,070				5,070		5,070
Treasury stock issued for acquisition			7,867			6,371	14,238
Exercise of stock options		1,697	14,978				16,675
Cash dividends ($.16 per share)				(9,042)			(9,042)
Total	$ 138,645						
December 31, 2001		$198,369	$396,104	$449,985	$5,070	$(39,330)	$1,010,198
Net Income	$ 17,652			17,652			17,652
Reclassification of unrealized gains on hedges to net income, net of $.5 income tax	1				1		1
Change in fair value of cash flow hedges, net of income tax	(19,674)				(19,674)		(19,674)
Exercise of stock options		1,189	9,167				10,356
Cash dividends ($.16 per share)				(9,147)			(9,147)
Total	$ (2,021)						
December 31, 2002		$199,558	$405,271	$458,490	$(14,603)	$(39,330)	$1,009,386

See accompanying Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollar amounts in tables, unless otherwise indicated, are in thousands, except per share amounts)

Note 1 - Summary of Significant Accounting Policies

Basis of Presentation and Consolidation

Accounting policies used by Noble Energy, Inc. and subsidiaries reflect industry practices and conform to accounting principles generally accepted in the United States of America. The more significant of such policies are briefly discussed below. The consolidated accounts include Noble Energy, Inc. (the "Company" or "Noble Energy") and the consolidated accounts of its wholly-owned subsidiaries. Effective December 31, 2001, Energy Development Corporation ("EDC"), a previously wholly-owned subsidiary of Samedan Oil Corporation ("Samedan"), was merged into Samedan, another previously wholly-owned subsidiary. Effective December 31, 2002, Samedan was merged into Noble Energy, Inc. Also effective December 31, 2002, Noble Trading, Inc. ("NTI") was merged into Noble Gas Marketing, Inc. ("NGM") under the new name of Noble Energy Marketing, Inc. ("NEMI"). Listed below are consolidated entities at December 31, 2002. All significant intercompany balances and transactions have been eliminated upon consolidation.

- NOBLE ENERGY, INC.
  - LaTex Resources Inc.
  - Noble Energy Marketing, Inc.
    - Noble Gas Pipeline, Inc.
  - NPM, Inc.
  - Samedan North Sea, Inc.
  - Samedan of North Africa, Inc.
    - EDC Ireland
    - Samedan International
      - Machalapower Cia. Ltda.
      - Samedan, Mediterranean Sea
      - Samedan Transfer Sub
    - Samedan Vietnam Limited
  - Samedan, Mediterranean Sea, Inc.
  - Samedan of Tunisia, Inc.
  - Samedan Oil of Canada, Inc.
  - Samedan Oil of Indonesia, Inc.
  - Samedan Pipe Line Corporation
  - Samedan Royalty Corporation
  - EDC Australia, Ltd.
  - EDC Ecuador Ltd.
    - EDC Ecuador Limited
  - EDC Portugal Ltd.
  - EDC (UK) Limited
    - EDC (Denmark) Inc.
    - EDC (Europe) Limited
      - EDC (ISE) Limited
      - EDC (Oilex) Limited
      - Brabant Oil Limited
  - Energy Development Corporation (Argentina), Inc.
  - Energy Development Corporation (China), Inc.
  - Energy Development Corporation (HIPS), Inc.
  - Gasdel Pipeline System Incorporated
  - HGC, Inc.
  - Producers Service, Inc.

Nature of Operations

The Company is an independent energy company engaged, directly or through its subsidiaries or various arrangements with other companies, in the exploration, development, production and marketing of crude oil and natural gas. The Company has exploration, exploitation and production operations domestically and internationally. The domestic areas consist of: offshore in the Gulf of Mexico and California; the Gulf Coast Region (Louisiana, New Mexico and Texas); the Mid-Continent Region (Oklahoma and Kansas); and the Rocky Mountain Region (Colorado, Montana, North Dakota, Wyoming and California). The international areas of operations include Argentina, China, Ecuador, Equatorial Guinea, the Mediterranean Sea (Israel), the North Sea (Denmark, Netherlands and United Kingdom) and Vietnam. The Company also markets domestic crude oil and natural gas production through NEMI.

Use of Estimates

The preparation of the consolidated financial statements requires management of the Company to make a number of estimates and assumptions relating to the reported amount of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. The Company's estimates of crude oil and natural gas reserves are the most significant. All of the reserve data in this Form 10-K are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved natural gas and crude oil reserves. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of crude oil and natural gas that are ultimately recovered. Other items subject to estimates and assumptions include the carrying amount of property, plant and equipment; valuation allowances for receivables, inventories and deferred income tax assets; environmental liabilities; valuation of derivative instruments; and assets and obligations related to employee benefits. Actual results could differ from those estimates.

Foreign Currency Translation

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 are included in other income on the statement of operations.

Materials and Supplies Inventories

Materials and supplies inventories, consisting principally of tubular goods and production equipment, are stated at the lower of cost or market, with cost being determined by the first-in, first-out method.

Property, Plant and Equipment

The Company accounts for its crude oil and natural gas properties under the successful efforts method of accounting. Under this method, costs to acquire mineral interests in crude oil and natural gas properties, to drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Capitalized costs of producing crude oil and natural gas properties are amortized to operations by the unit-of-production method based on proved developed crude oil and natural gas reserves on a property-by-property basis as estimated by Company engineers. Through December 31, 2002, estimated future restoration and abandonment costs are recorded by charges to DD&A expense over the productive lives of the related properties. The Company has provided $84.1 million for such future costs classified with accumulated DD&A in the December 31, 2002 balance sheet. The total estimated future dismantlement and restoration costs of $206.6 million, which consists of $188.7 million for the United States and $17.9 million for the North Sea, are included in future production and development costs for purposes of estimating the future net revenues relating to the Company's proved reserves. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated DD&A are eliminated from the accounts and the resulting gain or loss is recognized.

Individually significant unproved crude oil and natural gas properties are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance. Other unproved properties are amortized on a composite method based on the Company's experience of successful drilling and average holding period. Geological and geophysical costs, delay rentals and costs to drill exploratory wells that do not find proved reserves are expensed. Repairs and maintenance are expensed as incurred.

Proved crude oil and natural gas properties and other long-lived assets are periodically assessed to determine if circumstances indicate that the carrying amount of an asset may not be recoverable. 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.

Income Taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Capitalization of Interest

The Company capitalizes interest costs associated with the development and construction of significant properties or projects.

Statement of Cash Flows

For purposes of reporting cash flows, cash and short-term investments include cash on hand and investments purchased with original maturities of three months or less.

Basic Earnings Per Share and Diluted Earnings Per Share

Basic earnings per share ("EPS") of common stock have been computed on the basis of the weighted average number of shares outstanding during each period. The diluted EPS of common stock includes the effect of outstanding stock options. The following table summarizes the calculation of basic EPS and diluted EPS components as of December 31:

	2002		*2001*		*2000*	
(in thousands except per share amounts)	*Income (Numerator)*	*Shares (Denominator)*	*Income (Numerator)*	*Shares (Denominator)*	*Income (Numerator)*	*Shares (Denominator)*
Net income/shares	$17,652	57,196	$133,575	56,549	$191,597	55,999
Basic EPS	$.31		$2.36		$3.42	
Net income/shares	$17,652	57,196	$133,575	56,549	$191,597	55,999
Effect of Dilutive Securities						
Stock options		567		754		756
Adjusted net income and shares	$17,652	57,763	$133,575	57,303	$191,597	56,755
Diluted EPS	$.31		$2.33		$3.38	

The table below reflects the amount of options not included in the EPS calculation above, as they were antidilutive.

	2002	*2001*	*2000*
Options excluded from dilution calculation	2,229,978	1,485,303	1,633,149
Range of exercise prices	$35.40 - $43.21	$38.88 - $43.21	$35.94 - $40.38
Weighted average exercise price	$39.77	$41.29	$38.39

Accounting for Employee Stock-Based Compensation

At December 31, 2002, the Company has two stock-based employee compensation plans, which are described more fully in "Note 5 - Common Stock, Stock Options and Stockholder Rights." The Company accounts for those plans under the intrinsic value recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related Interpretations. At issuance, stock-based employee compensation cost was reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation.

(in thousands except per share amounts)	*2002*	*2001*	*2000*
Net income, as reported	$ 17,652	$133,575	$191,597
Add: Stock-based compensation cost recognized, net of related tax effects	392		477
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(6,394)	(7,538)	(8,170)
Pro forma net income	$ 11,650	$126,037	$183,904
Earnings per share:			
Basic - as reported	$ .31	$ 2.36	$ 3.42
Basic - pro forma	$ .20	$ 2.23	$ 3.28
Diluted - as reported	$ .31	$ 2.33	$ 3.38

Diluted - pro forma	$ .20	$ 2.20	$ 3.24

Fair value estimates are based on several assumptions and should not be viewed as indicative of the operations of the Company in future periods. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used for grants in 2002, 2001 and 2000, respectively, as follows:

(amounts expressed in percentages)	*2002*	*2001*	*2000*
Interest rate	4.78	5.46	6.25
Dividend yield	.43	.40	.40
Expected volatility	40.26	38.19	51.67
Expected life	9.73	9.64	9.71

The weighted average fair value of options granted using the Black-Scholes option pricing model for 2002, 2001 and 2000, respectively, is as follows:

	2002	*2001*	*2000*
Black-Scholes model weighted average fair value option price	$18.14	$23.86	$16.66

Revenue Recognition and Gas Imbalances

Noble Energy generally recognizes revenue when the product is delivered to a third-party purchaser.

NEMI records third-party sales, including derivative transactions, as gathering, marketing and processing revenues. NEMI records the amount paid to third parties as gathering, marketing and processing costs and expenses.

The Company follows the entitlements method of accounting for its natural gas imbalances. Natural gas imbalances occur when the Company sells more or less natural gas than it is entitled to under its ownership percentage of total natural gas production. Any excess amount received above the Company's share is treated as a liability. If less than the Company's entitlement is received, the underproduction is recorded as a receivable. The Company records the non-current liability in other deferred credits and non-current liabilities, and the current liability in other current liabilities. The Company's natural gas imbalance liabilities were $15.4 million and $15.5 million for 2002 and 2001, respectively. The Company records the non-current receivable in other assets and the current receivable in other current assets. The Company's natural gas imbalance receivables were $20.1 million and $20.9 million for 2002 and 2001, respectively, and are valued at the amount that is expected to be received.

Derivatives and Hedging Activities

The Company, directly or 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 and believes that losses from nonperformance are unlikely to occur. Hedging gains and losses related to the Company's crude oil and natural gas production are recorded in oil and gas sales and royalties.

The FASB issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," in June 1998. The Statement established 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 shareholders' equity as other comprehensive income 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 statement of operations, and requires that a company formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

The Company adopted SFAS No. 133 effective January 1, 2001. The adoption of this statement did not have a material impact on the Company's results of operations or financial position, as of the date of adoption. At December 31, 2002, the Company recorded crude oil and natural gas hedge liabilities of $22.5 million and other comprehensive loss, net of tax, of $14.6 million related to the Company's hedging contracts.

Self-Insurance

The Company self-insures the medical and dental coverage provided to certain of its employees, certain workers' compensation and the first $250,000 of its general liability coverage.

Liabilities are accrued for self-insured claims when sufficient information is available to reasonably estimate the amount of the loss.

Unconsolidated Subsidiary

Prior to January 2002, AMCCO was a 50 percent owned joint venture that owned an indirect 90 percent interest in 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 December 15, 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 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's debt 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 Company accounts for its investment in unconsolidated subsidiary under the equity method of accounting. AMPCO is an integral component of the Company's natural gas operations as AMPCO's function is to convert a portion of the Company's natural gas reserves to methanol for sale. For more information, see "Note 9 - Unconsolidated Subsidiary" of this Form 10-K.

Reclassification

Certain reclassifications have been made to the 2000 and 2001 consolidated financial statements to conform to the 2002 presentation. These reclassifications are not material to the Company's financial position.

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 adopted SFAS No. 143 on January 1, 2003 and will recognize, as the fair value of asset retirement obligations, $99.7 million related to the United States and $10.0 million related to the North Sea. The Company's accumulated provision for future retirement obligations was $84.1 million at December 31, 2002. The Company has not determined the cumulative effect of adoption of this standard. The expected future retirement obligation for the United States is $188.7 million and for the North Sea is $17.9 million. The difference between the expected future retirement obligation and the fair value of the retirement obligation will be expensed beginning in 2003 based on the credit-adjusted risk-free rate of 8.5 percent until the asset retirement date.

SFAS No. 148, "Accounting for Stock-Based Compensation," was issued in December 2002. This statement amends SFAS No. 123, "Accounting for Stock-Based Compensation," to provide for alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation. It also amends the disclosure provisions of that statement to require prominent disclosure about the effects on reported net income of an entity's accounting policy decisions with respect to stock-based employee compensation.

The Company currently accounts for stock-based employee compensation plans under the recognition and measurement principles of the APB Opinion No. 25, "Accounting for Stock Issued to Employees." The Company has not determined if it will adopt the fair value provisions of SFAS No. 123.

In June 2002, the EITF reached a consensus on certain issues contained in Topic 02-03, "Recognition and Reporting of Gains and Losses on Energy Trading Contracts" under EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." While the Company does not engage in material energy trading activities, the EITF has expanded its definition of energy trading activities to include the marketing activities in which the Company is engaged. As of January 1, 2003, the Company will present its gathering, marketing and processing activities in the statement of operations for all periods on a net rather than a gross basis. The change will significantly decrease reported marketing sales and purchases, but will have no effect on operating income or cash flow.

Note 2 - Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments. The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between two willing parties.

Cash, Short-Term Investments, Accounts Receivable and Accounts Payable

The carrying amounts approximate fair value due to the short-term nature or maturity of the instruments.

Crude Oil and Natural Gas Price Hedge Agreements

The fair value of crude oil and natural gas price hedges is the estimated amount the Company would receive or pay to terminate the hedge agreements at the reporting date taking into account creditworthiness of the hedging parties.

Long-Term Debt

The fair value of the Company's long-term debt is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to the Company for debt of the same remaining maturities.

The carrying amounts and estimated fair values of the Company's financial instruments, including current items, as of December 31, for each of the years are as follows:

	2002		*2001*	
(in thousands)	*Carrying Amount*	*Fair Value*	*Carrying Amount*	*Fair Value*
Crude oil and natural gas price hedge agreements	$ (22,520)	$ (22,520)	$ 16,032	$ 16,032
Long-term debt	$ (1,025,246)	$ (1,039,216)	$ (861,015)	$ (871,540)

Note 3 - Debt

A summary of debt at December 31 follows:

(in thousands)	*December 31, 2002*		*December 31, 2001*	
	Debt	Percentage Interest Rate	Debt	Percentage Interest Rate
$400 million Credit Agreement, maturity date November 2006	$ 380,000	2.47	$ 380,000	3.00
Note obtained in Aspect acquisition, due May 2004	11,508	6.25	31,015	6.25
7 1/4% Notes Due 2023	100,000	7.25	100,000	7.25
8% Senior Notes Due 2027	250,000	8.00	250,000	8.00
7 1/4% Senior Debentures Due 2097	100,000	7.25	100,000	7.25
AMCCO Note, due December 2004	125,000	8.95		
Israel Note, due 2003 and 2004	58,738	2.18		
Outstanding debt	1,025,246		861,015	
Less: unamortized discount	6,211		4,331	
current installment of long-term debt	41,919		19,507	
Long-term debt	$ 977,116		$ 837,177	

The Company's total long-term debt, net of unamortized discount, at December 31, 2002, was $977 million compared to $837 million at December 31, 2001. If the $125 million AMCCO debt had been included, the total long-term debt would have been $962 million at December 31, 2001. The ratio of debt-to-book capital (defined as the Company's total debt plus its equity) was 50 percent at December 31, 2002, compared with 47 percent at December 31, 2001.

The Company entered into a new $400 million five-year credit agreement on November 30, 2001, with certain commercial lending institutions, 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 60 to 145 basis points depending upon the percentage of utilization and credit rating. At December 31, 2002, there was $380 million borrowed against this credit agreement, which has a maturity date of November 30, 2006.

The Company also entered into a new $200 million 364-day credit agreement on November 27, 2002 with certain commercial lending institutions 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 December 31, 2002, there were no amounts outstanding under this credit agreement. The agreement has a maturity date of November 26, 2003 for the revolving commitment and a maturity date of November 25, 2004 for the term commitment that includes any balance remaining after the revolving commitment matures.

Financial covenants on both the $400 million and $200 million credit facilities include the following: (a) the ratio of EBITDAX to total interest expense for any consecutive period of four fiscal quarters ending on the last day of a fiscal quarter may not be less than 4.0 to 1.0; (b) the total debt to capitalization ratio, expressed as a percentage, may not exceed 60 percent at any time; and (c) the total asset value of the Company's restricted subsidiaries may not be less than $800 million at any time.

The Company had no short-term borrowings outstanding on December 31, 2002. The Company had a $25 million short-term note payable outstanding December 31, 2001, which was repaid January 28, 2002. The note was an uncommitted facility with an interest rate of 3.25 percent for the period December 28, 2001 to January 28, 2002.

Note 4 - Income Taxes

The following table details the difference between the federal statutory tax rate and the effective tax rate for the years ended December 31:

(amounts expressed in percentages)	*2002*	*2001*	*2000*
Statutory rate (benefit)	35.0	35.0	35.0
Effect of:			
State taxes, net of federal benefit	1.1	.3	.3
Difference between U.S. and foreign rates	24.5	4.9	.2
Other, net	(2.0)	.4	.5
Effective rate	58.6	40.6	36.0

The net current deferred tax asset (liability) in the following table is classified as other current assets in the consolidated balance sheet. The tax effects of temporary differences that gave rise to deferred tax assets and liabilities as of December 31 were:

(in thousands)	*2002*	*2001*
U.S. and State Current Deferred Tax Assets (Liabilities):		
Accrued expenses	$ 980	$ 15
Deferred income	387	626
Allowance for doubtful accounts	353	226
Marked to market - hedging contracts	7,864	(2,730)
Other		(17)
Net U.S. and State Current Deferred Tax Assets (Liabilities)	9,584	(1,880)
U.S. and State Non-current Deferred Tax Assets (Liabilities):		
Property, plant and equipment, principally due to differences in depreciation, amortization, lease impairment and abandonments	(183,338)	(177,382)
Accrued expenses	4,777	7,125
Deferred income	4,594	6,029
Allowance for doubtful accounts	5,935	5,767
Foreign and state income tax accruals	11,940	11,627
Post retirement benefits	9,668	2,489
Other	(245)	(245)
Net U.S. and State Non-current Deferred Tax Assets (Liabilities)	(146,669)	(144,590)
Total Net U.S. and State Deferred Tax Assets (Liabilities)	(137,085)	(146,470)
Foreign Non-current Deferred Tax Assets (Liabilities):		
Property, plant and equipment of foreign operations	(55,270)	(31,669)
Foreign loss carryforward	4,416	2,745
Net Foreign Non-current Deferred Tax Assets (Liabilities)	(50,854)	(28,924)
Valuation allowance	(4,416)	(2,745)
Total Net Deferred Tax Assets (Liabilities)	$(192,355)	$(178,139)

The components of income (loss) from operations before income taxes as of December 31 for each year are as follows:

(in thousands)	*2002*	*2001*	*2000*
Domestic	$ 3,067	$ 241,479	$ 268,489
Foreign	39,532	(16,869)	30,994
Total	$ 42,599	$ 224,610	$ 299,483

The income tax provision (benefit) relating to operations consists of the following for the years ended December 31:

(in thousands)	*2002*	*2001*	*2000*
U.S. current	$ (7,945)	$ 24,743	$ 65,358
U.S. deferred	1,421	53,591	32,311
State current	895	651	917
State deferred	(212)	360	334
Foreign current	14,675	6,200	8,341
Foreign deferred	16,113	5,490	625
Total	$ 24,947	$ 91,035	$107,886

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, management believes it is more likely than not that the Company will realize the benefits of these deductible differences, net of the existing valuation allowances at December 31, 2002. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carryforward period are reduced.

Note 5 - Common Stock, Stock Options and Stockholder Rights

The Company has two stock option plans, the 1992 Stock Option and Restricted Stock Plan ("1992 Plan") and the 1988 Non-Employee Director Stock Option Plan ("1988 Plan"). The Company accounts for these plans under APB Opinion No. 25.

Under the Company's 1992 Plan, the Board of Directors may grant stock options and award restricted stock. No restricted stock has been issued under the 1992 Plan. Since the adoption of the 1992 Plan, stock options have been issued at the market price on the date of grant. The earliest the granted options may be exercised is over a three year period at the rate of 33 1/3% each year commencing on the first anniversary of the grant date. The options expire ten years from the grant date. The 1992 Plan was amended in 2000, by a vote of the shareholders, to increase the maximum number of shares of common stock that may be issued under the 1992 Plan to 6,500,000 shares. At December 31, 2002, the Company had reserved 5,042,040 shares of common stock for issuance, including 1,079,604 shares available for grant, under its 1992 Plan.

The Company's 1988 Plan allows stock options to be issued to certain non-employee directors at the market price on the date of grant. The options may be exercised one year after issue and expire ten years from the grant date. The 1988 Plan provides for the grant of options to purchase a maximum of 550,000 shares of the Company's authorized but unissued common stock. The 1988 Plan was amended at the shareholders' annual meeting on April 24, 2001 to provide for the granting of a consistent number of stock options to each non-employee director annually (10,000 stock options for the first year of service and 5,000 stock options for each year thereafter) and to change the annual grant date to February 1, commencing February 1, 2002. At December 31, 2002, the Company had reserved 321,571 shares of common stock for issuance, including 89,786 shares available for grant, under its 1988 Plan.

The Company adopted a stockholder rights plan on August 27, 1997, designed to assure that the Company's stockholders receive fair and equal treatment in the event of any proposed takeover of the Company and to guard against partial tender offers and other abusive takeover tactics to gain control of the Company without paying all stockholders a fair price. The rights plan was not adopted in response to any specific takeover proposal. Under the rights plan, the Company declared a dividend of one right ("Right") on each share of Noble Energy, Inc. common stock. Each Right will entitle the holder to purchase one one-hundredth of a share of a new Series A Junior Participating Preferred Stock, par value $1.00 per share, at an exercise price of $150.00. The Rights are not currently exercisable and will become exercisable only in the event a person or group acquires beneficial ownership of 15 percent or more of Noble Energy, Inc. common stock. The dividend distribution was made on September 8, 1997, to stockholders of record at the close of business on that date. The Rights will expire on September 8, 2007.

A summary of the status of Noble Energy's stock option plans as of December 31, 2000, 2001 and 2002, and changes during each of the years then ended, is presented below.

	Options Outstanding		Options Exercisable	
	Number Outstanding	Exercise Price	Number Exercisable	Weighted Average Exercise Price
Outstanding at December 31, 1999	**3,484,938**	**$ 29.98**	**2,203,146**	**$ 31.14**
Options granted	774,343	$ 24.19		
Options exercised	(432,199)	$ 24.43		
Options canceled	(105,977)	$ 29.11		
Outstanding at December 31, 2000	**3,721,105**	**$ 29.44**	**2,408,522**	**$ 32.08**
Options granted	723,400	$ 42.77		
Options exercised	(509,161)	$ 24.97		
Options canceled	(81,267)	$ 33.11		
Outstanding at December 31, 2001	**3,854,077**	**$ 32.46**	**2,530,285**	**$ 32.10**
Options granted	732,500	$ 32.66		
Options exercised	(356,744)	$ 21.56		
Options canceled	(35,612)	$ 37.02		
Outstanding at December 31, 2002	**4,194,221**	**$ 33.38**	**2,871,943**	**$ 32.84**

The following table summarizes information about Noble Energy's stock options which were outstanding, and those which were exercisable, as of December 31, 2002.

Options Outstanding				Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$17.28 - $21.61	833,264	6.0 Years	$20.06	678,310	$20.06
$21.61 - $25.93	185,145	1.9 Years	$24.52	185,145	$24.52
$25.93 - $30.25	126,834	2.3 Years	$27.41	126,834	$27.41
$30.25 - $34.57	785,075	8.5 Years	$32.32	79,958	$31.27
$34.57 - $38.89	742,924	4.9 Years	$36.34	702,924	$36.24
$38.89 - $43.21	1,520,979	5.2 Years	$41.36	1,098,772	$40.69
	4,194,221	5.7 Years	$33.38	2,871,943	$32.84

Compensation expense totaling $643,170 and $781,275 was recognized in 2002 and 2000, respectively, due to the accelerated vesting of stock options as a result of the retirement of certain employees.

Note 6 - Employee Benefit Plans

Pension Plan and Other Postretirement Benefit Plans

The Company has a non-contributory defined benefit pension plan covering substantially all of its domestic employees. The benefits are based on an employee's years of service and average earnings for the 60 consecutive calendar months of highest compensation. The Company also has an unfunded restoration plan to ensure payments of amounts for which employees are entitled under the provisions of the pension plan, but which are subject to limitations imposed by federal tax laws. The Company's funding policy has been to make annual contributions equal to the actuarially computed liability to the extent such amounts are deductible for income tax purposes. Plan assets consist of equity securities and fixed income investments.

The Company sponsors other plans for the benefit of its employees and retirees. These plans include health care and life insurance benefits. The following table reflects the required disclosures on the Company's pension and other postretirement benefit plans at December 31:

	Pension Benefits		*Other Benefits*	
(in thousands)	*2002*	*2001*	*2002*	*2001*
Change in benefit obligation				
Benefit obligation at beginning of year	$ 89,587	$ 76,623	$ 2,688	$ 2,718
Adjustment for contributions paid in 2000		(54)		
Service cost	4,986	3,790	346	220
Interest cost	7,071	6,218	314	193
Amendments	380			
Plan participants' contributions			90	71
Actuarial (gain) loss	8,439	6,882	2,849	(333)
Benefits paid	(4,239)	(3,872)	(146)	(181)
Benefit obligation at year end	$106,224	$ 89,587	$ 6,141	$ 2,688
Change in plan assets				
Fair value of plan assets at beginning of year	$ 53,570	$ 55,487	$	$
Actual return on plan assets	(3,471)	(1,541)		
Employer contribution	10,800	3,497	146	180
Benefits paid	(4,239)	(3,873)	(146)	(180)
Fair value of plan at end of year	$ 56,660	$ 53,570	$	$
Fund status	$(49,564)	$(36,017)	$ (6,141)	$ (2,688)
Unrecognized net actuarial loss (gain)	23,366	6,826	2,472	(304)
Unrecognized prior service cost	2,525	2,451	(244)	(274)
Unrecognized net transition obligation (assets)	1,167	1,191		
Prepaid (accrued) benefit costs	$(22,506)	$(25,549)	$ (3,913)	$ (3,266)
Components of net periodic benefit cost				
Service cost	$ 4,986	$ 3,790	$ 346	$ 220
Interest cost	7,071	6,218	314	193
Expected return on plan assets	(5,474)	(4,899)		
Transition (assets) obligation recognition	24	24		
Amortization of prior service cost	306	292	(30)	(30)
Recognized net actuarial loss (gain)	845	(66)	73	(10)
Net periodic benefit cost	$ 7,758	$ 5,359	$ 703	$ 373
Weighted-average assumptions as of December 31,				
Discount rate	6.75%	7.25%	6.75%	7.25%
Expected return on plan assets	8.50%	8.50%		
Rate of compensation increase	4.00%	4.75%	4.00%	5.50%

The following table reflects the aggregate pension obligation components for the defined benefit pension plan and the restoration benefit plan, which are aggregated in the previous tables, at December 31:

	Defined Benefit Pension Plan		*Restoration Benefit Plan*	
(in thousands)	*2002*	*2001*	*2002*	*2001*
Aggregated pension benefits				
Aggregate fair value of plan assets	$ 56,660	$ 53,570	$	$
Aggregate accumulated benefit obligation	86,083	73,868	20,141	15,719
Fund status of net periodic benefit assets (obligation)	$(29,423)	$(20,298)	$(20,141)	$(15,719)

Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following results:

(in thousands)	*1-Percentage-Point increase*	*1-Percentage-Point decrease*
Total service and interest cost components	$ 733	$ 598
Total postretirement benefit obligation	$6,766	$5,591

Employee Savings Plan ("ESP")

The Company has an ESP that is a defined contribution plan. Participation in the ESP is voluntary and all regular employees of the Company are eligible to participate. The Company may match up to 100 percent of the participant's contribution not to exceed six percent of the employee's base compensation. The following table indicates the Company's contribution for the years ended December 31:

(in thousands)	*2002*	*2001*	*2000*
Employers' plan contribution	$2,302	$2,145	$1,858

Note 7 - Additional Balance Sheet and Statement of Operations Information

Included in accounts receivable-trade is an allowance for doubtful accounts at December 31:

(in thousands)	*2002*	*2001*
Allowance for doubtful accounts	$ 1,510	$ 638

Other current assets included the following at December 31:

(in thousands)	*2002*	*2001*
Deferred tax asset (liability)	$ 9,584	$ (1,880)
Prepaid federal income taxes		$ 66,131

Other current liabilities included the following at December 31:

(in thousands)	*2002*	*2001*
Gas imbalance liabilities	$ 1,090	$ 1,593
Accrued interest payable	$ 11,178	$ 10,692
Louisiana workers compensation	$ 7,611	$ 6,433

Crude oil and natural gas operations expense included the following for the years ended December 31:

(in thousands)	*2002*	*2001*	*2000*
Lease operating expense	$ 111,055	$ 109,626	$ 90,478
Workover expense	8,455	15,094	21,124
Production taxes	14,316	8,829	10,264
Total operations expense	$ 133,826	$ 133,549	$ 121,866

Crude oil and natural gas exploration expense included the following for the years ended December 31:

(in thousands)	*2002*	*2001*	*2000*
Dry hole expense	$ 81,396	$ 99,684	$ 38,463
Unproved lease amortization	21,254	17,213	16,075
Seismic	20,492	15,607	18,738
Other	27,559	19,592	11,592
Total exploration expense	$ 150,701	$ 152,096	$ 84,868

During the past three years, there was no third-party purchaser that accounted for more than 10 percent of the annual total crude oil and natural gas sales and royalties.

Note 8 - Derivatives and Hedging Activities

During 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. The table below depicts the various transactions for 2002.

Natural Gas		Crude Oil	
Hedge MMBTUpd	170,274	Hedge Bpd	5,247
Floor price range	$2.00 - $3.50	Floor price range	$23.00 - $24.00
Ceiling price range	$2.45 - $5.10	Ceiling price range	$29.30 - $30.10
Percent of daily production	44%	Percent of daily production	15%
Gain (loss) per Mcf	$.03	Gain (loss) per Bbl	$0

As of December 31, 2002, the Company had entered into costless collars related to its natural gas and crude oil production to support the Company's investment program as follows:

	Natural Gas		Crude Oil	
Production Period	MMBTU Per Day	Price Per MMBTU Floor - Ceiling	Bbls Per Day	Price Per Bbl Floor - Ceiling
1Q 2003	185,000	$3.87 - $4.82	15,000	$23.00 - $28.63
2Q 2003	185,000	$3.43 - $4.57	15,000	$23.00 - $28.63
3Q 2003	185,000	$3.43 - $4.60	10,000	$23.00 - $27.95
4Q 2003	185,000	$3.43 - $4.84	10,000	$23.00 - $27.95

The contracts entitle the Company (floating price payor) to receive settlement from the counterparty (fixed price payor) for each calculation period in amounts, if any, by which the settlement price for the last scheduled NYMEX trading day applicable for each calculation period is less than the floor price. The Company would pay the counterparty if the settlement price for the last scheduled NYMEX trading day applicable for each calculation period 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 calculation period. 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 calculation period.

During 2001, the Company had natural gas costless collars for the fourth quarter of 2001 for 50,000 MMBTU of natural gas per day, with a floor price of $3.25 per MMBTU and a ceiling price of $4.60 per MMBTU. The net effect of this fourth quarter 2001 hedge was a $.02 per Mcf increase in the average natural gas price for the year 2001. Of the 50,000 MMBTU per day of costless collars, 25,000 MMBTU per day were terminated early, at a gain. As a result, the Company recognized an additional $.70 per MMBTU on the 25,000 MMBTU of natural gas per day in 2001.

In addition to the hedging arrangements pertaining to the Company's production as described above, NEMI employs various derivative 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 NEMI are on an index basis; however, purchasers in the markets in which NEMI sells often require fixed or NYMEX related pricing. NEMI may use a derivative to convert the fixed or NYMEX sale to an index basis thereby determining the margin and minimizing the risk of price volatility. During 2002, NEMI had derivative transactions with broker-dealers that ranged from 986,000 MMBTU to 2,085,000 MMBTU of natural gas per day. At December 31, 2002, NEMI had in place derivatives ranging from approximately 20,000 MMBTU to 909,000 MMBTU of natural gas per day for January 2003 to May 2006 for future physical transactions.

In 2001, NGM had derivative transactions with broker-dealers that ranged from 1,157,000 MMBTU to 1,388,000 MMBTU of natural gas per day. During 2000, NGM had derivative transactions with broker-dealers that ranged from 423,000 MMBTU to 1,023,000 MMBTU of natural gas per day. NEMI records derivative gains or losses relating to fixed term sales as gathering, marketing and processing revenues in the periods in which the related contract is completed.

Note 9 - Unconsolidated Subsidiary

Prior to January 2002, AMCCO was a 50 percent owned joint venture that owned an indirect 90 percent interest in 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 December 15, 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 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's debt 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 total construction costs of the plant and supporting facilities as of December 31, 2002 were $417 million, with the Company responsible for $208.5 million. The plant is designed to produce 2,500 MTpd of methanol, which equates to approximately 20,000 Bpd. At this level of production, the plant would purchase approximately 125 MMcfpd from the 34 percent owned Alba field. The methanol plant has a 25-year contract to purchase natural gas from the Alba field.

AMPCO, AMPCO Marketing LLC, AMPCO Services LLC and Samedan Methanol continue to be accounted for using the equity method.

The following are summarized financial statements for subsidiaries accounted for using the equity method as of December 31, 2002 and AMCCO as of December 31, 2001 and 2000:

Consolidated Balance Sheet (Unaudited)
Equity Method Subsidiaries

(in thousands)	*2002*	*2001*
Assets		
Current assets	$ 74,832	$ 86,213
Non-current assets	412,134	432,431
Total Assets	$ 486,966	$ 518,644
Liabilities, Minority Interest and Members' Equity		
Current liabilities	$ 37,419	$ 14,892
Non-current liabilities		272,406
Minority interest		41,210
Members' equity	449,547	190,136
Total Liabilities, Minority Interest and Members' Equity	$ 486,966	$ 518,644

Consolidated Statement of Operations (Unaudited)
Equity Method Subsidiaries

(in thousands)	*2002*	*2001*	*2000*
Revenue			
Methanol sales	$ 97,476	$ 43,343	$
Other income	18,471	5,346	4,389
Total Revenue	$ 115,947	$ 48,689	$ 4,389
Less cost of goods sold	71,687	28,548	
Gross Margin	$ 44,260	$ 20,141	$ 4,389
Expenses			
DD&A	$ 20,763	$ 8,427	$
Other expenses		4,363	
Interest (net of amount capitalized)		19,069	1,005
Administrative	3,076	317	86
Total Expenses	$ 23,839	$ 32,176	$ 1,091
Net Income (Loss) Before Extraordinary Items	$ 20,421	$ (12,035)	$ 3,298
Extraordinary Items (1)	$	$ 24,776	$
Net Income (Loss)	$ 20,421	$ (36,811)	$ 3,298

(1) During the year, a prepayment penalty was recorded in connection with the early retirement of Series A-1 Secured Notes in 2002. The charge for the extraordinary item has been allocated to the Company's partner in AMCCO. Therefore, the Company has not recognized anything related to this loss in its financial statements.

Note 10 - Commitments and Contingencies

(a) The Company and its subsidiaries are involved in various legal proceedings in the ordinary course of business. These proceedings are subject to the inherent uncertainties in any litigation. The Company is defending itself vigorously in all such matters and does not believe that the ultimate disposition of such proceedings will have a material adverse effect on the Company's consolidated financial position, results of operations or liquidity.

(b) On October 15, 2002, Noble Gas Marketing, Inc., Samedan Oil Corporation and Aspect Resources L.L.C., collectively referred to as the "Noble Defendants," filed proofs of claim in the United States Bankruptcy Court for the Southern District of New York in response to bankruptcy filings by Enron Corporation and certain of its subsidiaries and affiliates, including Enron North America Corporation ("ENA"), under Chapter 11 of the U.S. Bankruptcy Code. The proofs of claim relate to certain natural gas sales agreements and aggregate approximately $18 million.

On December 13, 2002, ENA filed a complaint in which it objected to the Noble Defendants' proofs of claim, sought recovery of approximately $60 million from the Noble Defendants under the natural gas sales agreements, sought declaratory relief in respect of the offset rights of the Noble Defendants and sought to invalidate the arbitration provisions contained in certain of the agreements in issue. The Noble Defendants intend to vigorously defend against ENA's claims and do not believe that the ultimate disposition of the bankruptcy proceeding will have a material adverse effect on the Company's consolidated financial position, results of operations or liquidity.

Note 11 - Geographical Data

The Company has operations throughout the world and manages its operations by country. The following information is grouped into five components that are all primarily in the business of natural gas and crude oil exploration and production: United States, North Sea, Israel, Equatorial Guinea, and Other International, Corporate and Marketing. Other International includes operations in Argentina, China, Ecuador and Vietnam.

Year Ended December 31, 2002
(Dollars in Thousands)

	Consolidated	United States	North Sea	Israel	Equatorial Guinea	Other Int'l, Corporate & Marketing
REVENUES						
Oil Sales	$ 298,000	$ 152,575	$ 72,041	$	$ 45,830	$ 27,554
Gas Sales	402,602	382,946	19,497		3,052	(2,893)
Gathering, Marketing and Processing	714,091					714,091
Electricity Sales	18,257					18,257
Income from Unconsolidated Subsidiaries	9,532				9,532	
Other	1,246	100	389	(8)		765
Total Revenues	1,443,728	535,621	91,927	(8)	58,414	757,774
COSTS AND EXPENSES						
Oil and Gas Operations	133,826	110,849	10,812		9,848	2,317
Transportation	16,441		9,618			6,823
Oil and Gas Exploration	150,701	120,695	5,210	2,625	1,341	20,830
Gathering, Marketing and Processing	703,556					703,556
Electricity Generation	15,946					15,946
DD&A	285,286	241,113	28,279	31	5,849	10,014
SG&A	47,664	27,768	630	10	2,045	17,211
Interest Expense (net)	47,709					47,709
Total Costs and Expenses	1,401,129	500,425	54,549	2,666	19,083	824,406
INCOME (LOSS) BEFORE TAXES	$ 42,599	$ 35,196	$ 37,378	$ (2,674)	$ 39,331	$ (66,632)
LONG-LIVED ASSETS (PRIMARILY PROPERTY, PLANT AND EQUIPMENT, NET)						

As of December 31, 2002	$ 2,139,784	$ 1,225,501	$ 89,316	$ 180,267	$ 154,231	$ 490,469

Year Ended December 31, 2001
(Dollars in Thousands)

	Consolidated	United States	North Sea	Israel	Equatorial Guinea	Other Int'l, Corporate & Marketing
REVENUES						
Oil Sales	$ 260,908	$ 155,289	$ 39,972	$	$ 38,841	$ 26,806
Gas Sales	610,904	587,483	22,850		2,201	(1,630)
Gathering, Marketing and Processing	721,000					721,000
Electricity Sales						
Income (Loss) from Unconsolidated Subsidiaries	(5,075)				(5,075)	
Other	953	(267)	1,299		183	(262)
Total Revenues	1,588,690	742,505	64,121		36,150	745,914
COSTS AND EXPENSES						
Oil and Gas Operations	133,549	116,842	6,075		6,775	3,857
Transportation	16,012		8,772			7,240
Oil and Gas Exploration	152,096	100,492	34,950	380	39	16,235
Gathering, Marketing and Processing	708,292					708,292
Electricity Generation						
DD&A	284,016	253,232	16,537	23	3,889	10,335
SG&A	44,164	26,554	2,699	3	917	13,991
Interest Expense (net)	25,951					25,951
Total Costs and Expenses	1,364,080	497,120	69,033	406	11,620	785,901
INCOME (LOSS) BEFORE TAXES	$ 224,610	$ 245,385	$ (4,912)	$ (406)	$ 24,530	$ (39,987)
LONG-LIVED ASSETS (PRIMARILY PROPERTY, PLANT AND EQUIPMENT, NET)						
As of December 31, 2001	$ 1,953,211	$ 1,308,504	$ 103,781	$ 101,407	$ 87,461	$ 352,058

Year Ended December 31, 2000
(Dollars in Thousands)

	Consolidated	United States	North Sea	Israel	Equatorial Guinea	Other Int'l, Corporate & Marketing
REVENUES						
Oil Sales	$ 235,658	$ 165,299	$ 16,964	$	$ 25,501	$ 27,894
Gas Sales	564,936	539,868	24,392		235	441
Gathering, Marketing and Processing	589,933					589,933
Electricity Sales						
Income from Unconsolidated Subsidiaries	1,489				1,489	
Other	7,441	1,144	273			6,024
Total Revenues	1,399,457	706,311	41,629		27,225	624,292
COSTS AND EXPENSES						
Oil and Gas Operations	121,866	107,431	5,256		4,325	4,854
Transportation	9,241		6,072			3,169
Oil and Gas Exploration	84,868	80,367	1,396	581	62	2,462
Gathering, Marketing and Processing	574,266					574,266
Electricity Generation						
DD&A	230,800	207,690	12,297		1,361	9,452
SG&A	47,291	36,781	2,049		1,107	7,354
Interest Expense (net)	31,642					31,642
Total Costs and Expenses	1,099,974	432,269	27,070	581	6,855	633,199
INCOME (LOSS) BEFORE TAXES	$ 299,483	$ 274,042	$ 14,559	$ (581)	$ 20,370	$ (8,907)
LONG-LIVED ASSETS (PRIMARILY PROPERTY, PLANT AND EQUIPMENT, NET)						
As of December 31, 2000	$ 1,485,123	$ 1,047,750	$ 90,231	$ 69,726	$ 76,898	$ 200,518

Note 12 - Company Stock Repurchase Forward Program

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 program was scheduled to mature in January 2003 but has been extended to January 2004. Under the provisions of the agreement with the bank, 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 (to $16.77 per share) 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 December 31, 2002, the fair value of the Company's obligation under the contract would be an obligation to pay approximately $36.1 million to the bank (and hold the shares as treasury stock), or the bank would return 81,946 shares of Company stock to the Company, or the bank would pay $3.1 million to the Company.

Supplemental Oil and Gas Information

(Unaudited)

There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured, and estimates of engineers other than Noble Energy's might differ materially from the estimates set forth herein. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The procedures and methods used to estimate approximately 80 percent of the Company's proved reserves have been audited by a third party. This audit of procedures and methods included all of the Company's major international properties, whose reserves were also estimated by third parties. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered. China, Ecuador and Equatorial Guinea are subject to production sharing contracts.

Proved Gas Reserves (Unaudited)

The following reserve schedule was developed by the Company's reserve engineers and sets forth the changes in estimated quantities of proved gas reserves of the Company during each of the three years presented.

	Natural Gas and Casinghead Gas (MMcf)						
Proved reserves as of:	*United States*	*Argentina*	*Ecuador*	*Equatorial Guinea*	*Israel*	*North Sea*	***Total***
January 1, 2002	751,283	4,348	87,500	438,214	378,001	20,661	**1,680,007**
Revisions of previous estimates	(37,566)	(37)	281	(245)		18	**(37,549)**
Extensions, discoveries and other additions	42,806				72,306		**115,112**
Production	(119,664)	(424)	(2,788)	(12,549)		(6,201)	**(141,626)**
Sale of minerals in place	(20,290)						**(20,290)**
Purchase of minerals in place	5,147						**5,147**
December 31, 2002	621,716	3,887	84,993	425,420	450,307	14,478	**1,600,801**
Proved reserves as of:							
January 1, 2001	752,387	4,544	87,500	383,292	218,154	28,752	**1,474,629**
Revisions of previous estimates	(46,886)	36		(2,550)	159,847	(1,583)	**108,864**
Extensions, discoveries and other additions	129,172	371		66,410			**195,953**
Production	(134,507)	(603)		(8,938)		(6,508)	**(150,556)**
Sale of minerals in place	(246)						**(246)**
Purchase of minerals in place	51,363						**51,363**
December 31, 2001	751,283	4,348	87,500	438,214	378,001	20,661	**1,680,007**
Proved reserves as of:							
January 1, 2000	759,781	5,221	87,500	384,102		26,452	**1,263,056**
Revisions of previous estimates	(7,022)	44		131		7,864	**1,017**
Extensions, discoveries and other additions	135,844				218,154	3,101	**357,099**
Production	(136,010)	(721)		(941)		(8,665)	**(146,337)**
Sale of minerals in place	(4,840)						**(4,840)**
Purchase of minerals in place	4,634						**4,634**
December 31, 2000	752,387	4,544	87,500	383,292	218,154	28,752	**1,474,629**
Proved developed gas reserves as of:							
January 1, 2003	576,378	3,664	34,436	425,419		14,478	**1,054,375**
January 1, 2002	721,926	3,996		438,213		20,662	**1,184,797**
January 1, 2001	690,301	4,544		383,292		25,652	**1,103,789**
January 1, 2000	703,166	5,221		11,687			26,452

Proved Oil Reserves (Unaudited)

The following reserve schedule was developed by the Company's reserve engineers and sets forth the changes in estimated quantities of proved oil reserves of the Company during each of the three years presented.

	Crude Oil and Condensate (Bbls in thousands)					
Proved reserves as of:	*United States*	*Argentina*	*China*	*Equatorial Guinea*	*North Sea*	***Total***
January 1, 2002	71,672	10,277	9,768	79,790	11,114	**182,621**
Revisions of previous estimates	(5,331)	36		(34)	(27)	**(5,356)**
Extensions, discoveries and other additions	2,929		1,162	33,182		**37,273**
Production	(6,652)	(1,030)		(1,919)	(2,864)	**(12,465)**
Sale of minerals in place	(732)					**(732)**
Purchase of minerals in place	137					**137**
December 31, 2002	62,023	9,283	10,930	111,019	8,223	**201,478**
Proved reserves as of:						
January 1, 2001	69,700	9,437	9,768	47,446	12,418	**148,769**
Revisions of previous estimates	324	(6)		(272)	407	**453**
Extensions, discoveries and other additions	7,453	1,846		34,303		**43,602**
Production	(7,363)	(1,000)		(1,687)	(1,711)	**(11,761)**
Sale of minerals in place	(37)					**(37)**
Purchase of minerals in place	1,595					**1,595**
December 31, 2001	71,672	10,277	9,768	79,790	11,114	**182,621**
Proved reserves as of:						
January 1, 2000	65,523	10,285	9,768	30,684	5,786	**122,046**
Revisions of previous estimates	(1,493)	68		185	(366)	**(1,606)**
Extensions, discoveries and other additions	12,788			17,491	5,731	**36,010**
Production	(7,309)	(916)		(914)	(654)	**(9,793)**
Sale of minerals in place	(935)				(229)	**(1,164)**
Purchase of minerals in place	1,126				2,150	**3,276**
December 31, 2000	69,700	9,437	9,768	47,446	12,418	**148,769**
Proved developed oil reserves as of:						
January 1, 2003	52,847	8,331	10,930	78,746	8,223	**159,077**
January 1, 2002	64,534	8,866	9,768	61,897	11,114	**156,179**
January 1, 2001	58,903	9,437	9,768	47,446	5,728	**131,282**
January 1, 2000	60,618	10,285	9,768	14,743	3,986	**99,400**

Proved Reserves. Proved reserves are estimated quantities of crude oil, natural gas, natural gas liquids and condensate liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved Developed Reserves. Proved developed reserves are proved reserves that are expected to be recovered through existing wells with existing equipment and operating methods.

Oil and Gas Operations (Unaudited)

Aggregate results of operations for each period ended December 31, in connection with the Company's crude oil and natural gas producing activities, are shown below. Amounts are presented in accordance with SFAS No. 19 and may not agree with amounts determined using traditional industry definitions.

(in thousands)

December 31, 2002	*United States*	*Equatorial Guinea*	*Israel*	*North Sea*	*Other Int'l*	***Total***
Revenues	$ 535,697	$ 45,830	$	$ 91,538	$ 27,537	**$ 700,602**
Production costs	142,578	8,840	10	21,061	13,093	**185,582**
Exploration expenses	102,323	1,341	1,725	5,032	20,733	**131,154**
DD&A and valuation provision	258,310	5,835	909	28,350	9,606	**303,010**
Income (loss)	32,486	29,814	(2,644)	37,095	(15,895)	**80,856**
Income tax expense (benefit)	11,705	13,825		17,346	666	**43,542**
Result of operations from producing activities (excluding corporate overhead and interest costs)	$ 20,781	$ 15,989	$ (2,644)	$ 19,749	$ (16,561)	**$ 37,314**
December 31, 2001						
Revenues	$ 742,909	$ 38,841	$	$ 54,051	$ 19,999	**$ 855,800**
Production costs	146,254	5,381	3	8,774	7,675	**168,087**
Exploration expenses	86,619	39	5	33,224	17,021	**136,908**
DD&A and valuation provision	266,805	3,830	382	18,171	8,679	**297,867**
Income (loss)	243,231	29,591	(390)	(6,118)	(13,376)	**252,938**
Income tax expense (benefit)	85,498	14,429		(2,721)	(700)	**96,506**
Result of operations from producing activities (excluding corporate overhead and interest costs)	$ 157,733	$ 15,162	$ (390)	$ (3,397)	$ (12,676)	**$ 156,432**
December 31, 2000						
Revenues	$ 705,270	$ 25,501	$	$ 35,284	$ 25,298	**$ 791,353**
Production costs	129,359	5,010		5,962	6,952	**147,283**
Exploration expenses	78,955	121	581	2,739	2,169	**84,565**
DD&A and valuation provision	222,161	1,355		12,231	8,292	**244,039**
Income (loss)	274,795	19,015	(581)	14,352	7,885	**315,466**
Income tax expense (benefit)	96,675	8,978		4,316	5,033	**115,002**
Result of operations from producing activities (excluding corporate overhead and interest costs)	$ 178,120	$ 10,037	$ (581)	$ 10,036	$ 2,852	**$ 200,464**

Costs Incurred in Oil and Gas Activities (Unaudited)

Costs incurred in connection with the Company's crude oil and natural gas acquisition, exploration and development activities for each of the years are shown below. Amounts are presented in accordance with SFAS No. 19 and may not agree with amounts determined using traditional industry definitions.

(in thousands)						
December 31, 2002	*United States*	*Equatorial Guinea*	*Israel*	*North Sea*	*Other Int'l*	***Total***
Property acquisition costs						
Proved	$ 7,873	$	$	$ 115	$	**$ 7,988**
Unproved	28,023			(238)	2,730	**30,515**
Total	$ 35,896	$	$	$ (123)	$ 2,730	**$ 38,503**
Exploration costs	$ 153,437	$ 1,351	$ 1,725	$ 5,062	$ 20,935	**$ 182,510**
Development costs	$ 131,244	$ 51,839	$ 14,767	$ 9,892	$ 60,934	**$ 268,676**
December 31, 2001						
Property acquisition costs						
Proved	$ 91,251	$	$	$ 6,318	$	**$ 97,569**
Unproved	76,808			2,167	2,310	**81,285**
Total	$ 168,059	$	$	$ 8,485	$ 2,310	**$ 178,854**
Exploration costs	$ 134,247	$ 4,003	$ 131	$ 34,766	$ 19,233	**$ 192,380**
Development costs	$ 279,297	$ 10,364	$ 11,163	$ 17,338	$ 75,910	**$ 394,072**
December 31, 2000						
Property acquisition costs						
Proved	$ 6,822	$	$ 50,861	$ 41,284	$	**$ 98,967**
Unproved	12,559		1,927	2,218	858	**17,562**
Total	$ 19,381	$	$ 52,788	$ 43,502	$ 858	**$ 116,529**
Exploration costs	$ 115,728	$ 62	$ 11,387	$ 1,396	$ 2,135	**$ 130,708**
Development costs	$ 180,339	$ 36,820	$ 1,502	$ 2,219	$ 44,648	**$ 265,528**

Aggregate Capitalized Costs (Unaudited**)**

Aggregate capitalized costs relating to the Company's crude oil and natural gas producing activities, and related accumulated DD&A, as of December 31 are shown below:

	2002			*2001*		
(in thousands)	*U. S.*	*Int'l*	***Total***	*U. S.*	*Int'l*	***Total***
Unproved oil and gas properties	$ 138,319	$ 16,532	**$ 154,851**	$ 142,232	$ 14,041	**$ 156,273**
Proved oil and gas properties	3,053,256	1,069,914	**4,123,170**	3,007,757	757,885	**3,765,642**
	3,191,575	1,086,446	**4,278,021**	3,149,989	771,926	**3,921,915**
Accumulated DD&A	(1,972,282)	(189,540)	**(2,161,822)**	(1,855,352)	(138,425)	**(1,993,777)**
Net capitalized costs	$ 1,219,293	$ 896,906	**$ 2,116,199**	$ 1,294,637	$ 633,501	**$ 1,928,138**

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves
(Unaudited)

The following information is based on the Company's best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows as of December 31, 2002, 2001 and 2000 in accordance with SFAS No. 69. The Standard requires the use of a 10 percent discount rate. This information is not the fair market value nor does it represent the expected present value of future cash flows of the Company's proved oil and gas reserves.

December 31, 2002	*United States*	*Ecuador*	*Equatorial Guinea*	*Israel*	*North Sea*	*Other Int'l*	***Total***
(in millions of dollars)							
Future cash inflows	$ 4,743	$ 268	$ 3,111	$1,181	$ 294	$ 648	**$ 10,245**
Future production and development costs	1,506	73	661	301	110	238	**2,889**
Future income tax expenses	985	33	860	263	68	111	**2,320**
Future net cash flows	2,252	162	1,590	617	116	299	**5,036**
10% annual discount for estimated timing of cash flows	877	59	953	301	21	93	**2,304**
Standardized measure of discounted future net cash flows	$ 1,375	$ 103	$ 637	$ 316	$ 95	$ 206	**$ 2,732**

December 31, 2001							
(in millions of dollars)							
Future cash inflows	$ 3,399	$ 264	$ 1,576	$ 900	$ 281	$ 317	**$ 6,737**
Future production and development costs	1,618	103	381	150	84	168	**2,504**
Future income tax expenses	437	26	598	193	49	24	**1,327**
Future net cash flows	1,344	135	597	557	148	125	**2,906**
10% annual discount for estimated timing of cash flows	562	56	406	364	25	65	**1,478**
Standardized measure of discounted future net cash flows	$ 782	$ 79	$ 191	$ 193	$ 123	$ 60	**$ 1,428**

December 31, 2000							
(in millions of dollars)							
Future cash inflows	$ 8,825	$ 305	$ 1,125	$ 524	$ 379	$ 462	**$ 11,620**
Future production and development costs	1,759	90	178	92	89	186	**2,394**
Future income tax expenses	1,909	58	256	117	78	74	**2,492**
Future net cash flows	5,157	157	691	315	212	202	**6,734**
10% annual discount for estimated timing of cash flows	2,037	62	273	124	84	80	**2,660**
Standardized measure of discounted future net cash flows	$ 3,120	$ 95	$ 418	$ 191	$ 128	$ 122	**$ 4,074**

The future net cash inflows for 2002, 2001 and 2000 do not include cash flows relating to the Company's anticipated future methanol or power sales.

Future cash inflows are computed by applying year-end prices (with a weighted average price of $29.48 per Bbl of crude oil and $3.95 per Mcf of natural gas, after adjusting for differentials on a property-by-property basis) to year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements at year-end.

The Company estimates that a $1.00 per Bbl change or a $.10 per Mcf change in the average crude oil price or the average natural gas price, respectively, from the year-end price would change the discounted future net cash flows before income taxes by approximately $105 million or $64 million, respectively.

Future production and development costs, which include dismantlement and restoration expense, are computed by estimating the expenditures to be incurred in developing and producing the Company's proved crude oil and natural gas reserves at the end of the year, based on year-end costs, and assuming continuation of existing economic conditions.

Future income tax expenses are computed by applying the appropriate year-end statutory tax rates to the estimated future pretax net cash flows relating to the Company's proved crude oil and natural gas reserves, less the tax bases of the properties involved. The future income tax expenses give effect to tax credits and allowances, but do not reflect the impact of general and administrative costs and exploration expenses of ongoing operations relating to the Company's proved crude oil and natural gas reserves.

At December 31, 2002, the Company estimated natural gas imbalance receivables of $20.1 million and estimated natural gas imbalance liabilities of $15.4 million; at year-end 2001, $20.9 million in receivables and $15.5 million in liabilities; and at year-end 2000, $18.5 million in receivables and $14.2 million in liabilities. Neither the natural gas imbalance receivables nor natural gas imbalance liabilities have been included in the standardized measure of discounted future net cash flows as of each of the three years ended December 31, 2002, 2001 and 2000.

Sources of Changes in Discounted Future Net Cash Flows (Unaudited)

Principal changes in the aggregate standardized measure of discounted future net cash flows attributable to the Company's proved crude oil and natural gas reserves, as required by SFAS No. 69, at year-end are shown below.

(in millions)	*2002*	*2001*	*2000*
Standardized measure of discounted future net cash flows at the beginning of the year	$ 1,428	$ 4,074	$ 1,493
Extensions, discoveries and improved recovery, less related costs	486	448	1,462
Revisions of previous quantity estimates	(158)	114	(20)
Changes in estimated future development costs	(243)	(128)	(52)
Purchases (sales) of minerals in place	(13)	108	69
Net changes in prices and production costs	1,636	(3,376)	2,448
Accretion of discount	208	564	185
Sales of oil and gas produced, net of production costs	(553)	(713)	(662)
Development costs incurred during the period	254	220	172
Net change in income taxes	(667)	908	(1,207)
Change in timing of estimated future production, and other	354	(791)	186
Standardized measure of discounted future net cash flows at the end of the year	$ 2,732	$ 1,428	$ 4,074

Supplemental Quarterly Financial Information (Unaudited)

Supplemental quarterly financial information for the years ended December 31, 2002 and 2001 is as follows:

	Quarter Ended			
(in thousands except per share amounts)	*Mar. 31,*	*June 30,*	*Sept. 30,*	*Dec. 31,*
2002				
Revenues	$ 317,650	$ 330,292	$ 339,666	$ 456,120
Net income (loss)	$ (15,098)	$ 17,119	$ (1,190)	$ 16,821
Basic earnings (loss) per share	$ (.26)	$ .30	$ (.02)	$ .29
Diluted earnings (loss) per share	$ (.26)	$ .30	$ (.02)	$ .29
2001				
Revenues	$ 564,206	$ 417,698	$ 308,673	$ 301,663
Net income (loss)	$ 105,910	$ 51,334	$ 3,808	$ (27,476)
Basic earnings (loss) per share	$ 1.88	$ .91	$ .07	$ (.48)
Diluted earnings (loss) per share	$ 1.84	$ .89	$ .07	$ (.48)

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

Effective May 14, 2002, the Board of Directors of Noble Energy, Inc., after careful consideration and based upon the recommendation of its Audit Committee, dismissed its current independent public accountant, Arthur Andersen LLP. This dismissal followed the decision by the Board of Directors to seek proposals from other independent auditors to audit the Company's consolidated financial statements for its fiscal year ended December 31, 2002.

Effective May 14, 2002, the Board of Directors, based on the recommendation of its Audit Committee, retained KPMG LLP as its independent auditor with respect to the audit of the Company's consolidated financial statements for its fiscal year ended December 31, 2002.

During the Company's two most recent fiscal years ended December 31, 2001, and during the subsequent interim period preceding the replacement of Arthur Andersen LLP, there was no disagreement between the Company and Arthur Andersen LLP on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure that, if not resolved to Arthur Andersen LLP's satisfaction, would have caused Arthur Andersen LLP to make reference to the subject matter of the disagreement in connection with its report. The audit reports of Arthur Andersen LLP on the consolidated financial statements of the Company as of and for the last two fiscal years ended December 31, 2001 did not contain any adverse opinion or disclaimer of opinion, nor were these opinions qualified or modified as to uncertainty, audit scope or accounting principles.

During the Company's two most recent fiscal years ended December 31, 2001, and during the subsequent interim period preceding the replacement of Arthur Andersen LLP, the Company had not consulted with KPMG LLP or other independent auditors regarding the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on the Company's financial statements.

PART III

Item 10. Directors and Executive Officers of the Registrant.

The section entitled "Election of Directors" in the Registrant's proxy statement for the 2003 annual meeting of stockholders sets forth certain information with respect to the directors of the Registrant and is incorporated herein by reference. Certain information with respect to the executive officers of the Registrant is set forth under the caption "Executive Officers of the Registrant" in Part I of this report.

The section entitled "Section 16(a) Beneficial Ownership Reporting Compliance" in the Registrant's proxy statement for the 2003 annual meeting of stockholders sets forth certain information with respect to compliance with Section 16(a) of the Securities Exchange Act of 1934, as amended, and is incorporated herein by reference.

Item 11. Executive Compensation.

The section entitled "Executive Compensation" in the Registrant's proxy statement for the 2003 annual meeting of stockholders sets forth certain information with respect to the compensation of management of the Registrant, and except for the report of the Compensation, Benefits and Stock Option Committee of the Board of Directors and the information therein under "Executive Compensation--Performance Graph" is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management.

The sections entitled "Security Ownership of Certain Beneficial Owners" and "Security Ownership of Directors and Executive Officers" in the Registrant's proxy statement for the 2003 annual meeting of stockholders set forth certain information with respect to the ownership of the Registrant's common stock and are incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions.

The section entitled "Certain Transactions" in the Registrant's proxy statement for the 2003 annual meeting of stockholders sets forth certain information with respect to certain relationships and related transactions, and is incorporated herein by reference.

Item 14. Controls and Procedures.

(a) Evaluation of Disclosure Controls and Procedures. As of a date within 90 days prior to the filing of this report, an evaluation of the effectiveness of the Company's disclosure controls and procedures was carried out under the supervision and with the participation of Charles D. Davidson, the Company's Chief Executive Officer, and James L. McElvany, the Company's Chief Financial Officer. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective.

(b) Changes to Internal Controls. There were no significant changes to the Company's internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Item 15. Financial Statement Schedules, Exhibits and Reports on Form 8-K.

(a) The following documents are filed as a part of this report:

(1) Financial Statements and Financial Statement Schedules and Supplementary Data: These documents are listed in the Index to Consolidated Financial Statements in Item 8 hereof.

(2) Exhibits: The exhibits required to be filed by this Item 15 are set forth in the Index to Exhibits accompanying this report.

(b) The Registrant made no filings on Form 8-K during the quarter ended December 31, 2002.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

NOBLE ENERGY, INC.

Date: March 11, 2003

By: /s/ James L. McElvany
James L. McElvany,
Senior Vice President, Chief Financial Officer and Treasurer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Capacity in which signed	Date
/s/ Charles D. Davidson Charles D. Davidson	Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)	March 11, 2003
/s/ James L. McElvany James L. McElvany	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)	March 11, 2003
/s/ Michael A. Cawley Michael A. Cawley	Director	March 11, 2003
/s/ Edward F. Cox Edward F. Cox	Director	March 11, 2003
/s/ James C. Day James C. Day	Director	March 11, 2003
/s/ Kirby L. Hedrick Kirby L. Hedrick	Director	March 11, 2003
/s/ Dale P. Jones Dale P. Jones	Director	March 11, 2003
/s/ Bruce A. Smith Bruce A. Smith	Director	March 11, 2003

CERTIFICATION

I, Charles D. Davidson, certify that:

1. I have reviewed this annual report on Form 10-K of Noble Energy, Inc.;

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

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

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

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

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

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

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

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

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

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

Date: March 11, 2003

/s/ CHARLES D. DAVIDSON
CHARLES D. DAVIDSON
Chief Executive Officer

CERTIFICATION

I, James L. McElvany, certify that:

1. I have reviewed this annual report on Form 10-K of Noble Energy, Inc.;

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

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

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

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

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

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

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

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

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

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

Date: March 11, 2003

/s/ JAMES L. McELVANY
JAMES L. McELVANY
Chief Financial Officer

INDEX TO EXHIBITS

Exhibit Number		Exhibit **
3.1	--	Certificate of Incorporation, as amended, of the Registrant as currently in effect (filed as Exhibit 3.2 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1987 and incorporated herein by reference).
3.2	--	Certificate of Designations of Series A Junior Participating Preferred Stock of the Registrant dated August 27, 1997 (filed Exhibit A of Exhibit 4.1 to the Registrant's Registration Statement on Form 8-A filed on August 28, 1997 and incorporated herein by reference).
3.3	--	Composite copy of Bylaws of the Registrant as currently in effect (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Event: January 29, 2002) dated February 8, 2002 and incorporated herein by reference).
3.4	--	Certificate of Designations of Series B Mandatorily Convertible Preferred Stock of the Registrant dated November 9, 1999 (filed as Exhibit 3.4 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999 and incorporated herein by reference).
4.1	--	Indenture dated as of October 14, 1993 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee, relating to the Registrant's 7 1/4% Notes Due 2023, including form of the Registrant's 7 1/4% Notes Due 2023 (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1993 and incorporated herein by reference).
4.2	--	Indenture relating to Senior Debt Securities dated as of April 1, 1997 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 and incorporated herein by reference).
4.3	--	First Indenture Supplement relating to $250 million of the Registrant's 8% Senior Notes Due 2027 dated as of April 1, 1997 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee (filed as Exhibit 4.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 and incorporated herein by reference).
4.4	--	Second Indenture Supplement, between the Company and U.S. Trust Company of Texas, N.A. as trustee, relating to $100 million of the Registrant's 7 1/4% Senior Debentures Due 2097 dated as of August 1, 1997 (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997 and incorporated herein by reference).
4.5	--	Rights Agreement, dated as of August 27, 1997, between the Registrant and Liberty Bank and Trust Company of Oklahoma City, N.A., as Right's Agent (filed as Exhibit 4.1 to the Registrant's Registration Statement on Form 8-A filed on August 28, 1997 and incorporated herein by reference).
4.6	--	Amendment No. 1 to Rights Agreement dated as of December 8, 1998, between the Registrant and Bank One Trust Company, as successor Rights Agent to Liberty Bank and Trust Company of Oklahoma City, N.A. (filed as Exhibit 4.2 to the Registrant's Registration Statement on Form 8-A/A (Amendment No. 1) filed on December 14, 1998 and incorporated herein by reference).
10.1 *	--	Restoration of Retirement Income Plan for Certain Participants in the Noble Affiliates Retirement Plan dated September 21, 1994, effective as of May 19, 1994 (filed as Exhibit 10.5 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1994 and incorporated herein by reference).
10.2 *	--	Amendment No. 1 to the Restoration of Retirement Income Plan for Certain Participants in the Noble Affiliates Retirement Plan executed March 26, 2002, filed herewith.

Exhibit Number		Exhibit **
10.3 *	--	Noble Energy, Inc. Restoration Trust effective August 1, 2002, filed herewith.
10.4 *	--	Noble Affiliates, Inc. Deferred Compensation Plan (formerly known as the Noble Affiliates Thrift Restoration Plan dated May 9, 1994) as restated effective August 1, 2001, filed herewith.
10.5 *	--	Noble Affiliates, Inc. 1992 Stock Option and Restricted Stock Plan, as amended, dated January 27, 2003, filed herewith.
10.6 *	--	1982 Stock Option Plan of the Registrant (filed as Exhibit 4.1 to the Registrant's Registration Statement on Form S-8 (Registration No. 2-81590) and incorporated herein by reference).
10.7 *	--	Amendment No. 1 to the 1982 Stock Option Plan of the Registrant (filed as Exhibit 4.2 to the Registrant's Registration Statement on Form S-8 (Registration No. 2-81590) and incorporated herein by reference).
10.8 *	--	Amendment No. 2 to the 1982 Stock Option Plan of the Registrant (filed as Exhibit 10.11 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1995 and incorporated herein by reference).
10.9 *	--	1988 Nonqualified Stock Option Plan for Non-Employee Directors of the Registrant, as amended and restated, effective as of April 23, 2002 (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 and incorporated herein by reference).
10.10*	--	Non-Employee Director Fee Deferral Plan dated April 25, 2002 and effective as of April 23, 2002 (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 and incorporated herein by reference).
10.11*	--	Form of Indemnity Agreement entered into between the Registrant and each of the Registrant's directors and bylaw officers (filed as Exhibit 10.18 to the Registrant's Annual Report of Form 10-K for the year ended December 31, 1995 and incorporated herein by reference).
10.12	--	Guaranty of the Registrant dated October 28, 1982, guaranteeing certain obligations of Samedan (filed as Exhibit 10.12 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1993 and incorporated herein by reference).
10.13	--	Stock Purchase Agreement dated as of July 1, 1996, between Samedan Oil Corporation and Enterprise Diversified Holdings Incorporated (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K (Date of Event: July 31, 1996) dated August 13, 1996 and incorporated herein by reference).
10.14	--	Noble Preferred Stock Remarketing and Registration Rights Agreement dated as of November 10, 1999 by and among the Registrant, Noble Share Trust, The Chase Manhattan Bank, and Donaldson, Lufkin & Jenrette Securities Corporation (filed as Exhibit 10.15 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999 and incorporated herein by reference).
10.15*	--	Letter agreement dated February 1, 2002 between the Registrant and Charles D. Davidson, terminating Mr. Davidson's employment agreement and entering into the attached Change of Control Agreement (filed as Exhibit 10.17 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2001 and incorporated herein by reference).

Exhibit Number		Exhibit **
10.16*	--	Form of Change of Control Agreement entered into between the Registrant and each of the Registrant's officers, with schedule setting forth differences in Change of Control Agreements (filed as Exhibit 10.18 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2001 and incorporated herein by reference).
10.17	--	Five-year Credit Agreement dated as of November 30, 2001 among the Registrant, as borrower, JPMorgan Chase Bank, as the administrative agent for the lenders, Societe Generale, as the syndication agent for the lenders, Mizuho Financial Group, Credit Lyonnais, New York Branch, The Royal Bank of Scotland PLC, and Deutsche Bank Ag New York Branch, as co-documentation agents, and certain commercial lending institutions, as lenders (filed as Exhibit 10.19 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2001 and incorporated herein by reference).
10.18	--	364-day Credit Agreement dated as of November 30, 2001 among the Registrant, as borrower, JPMorgan Chase Bank, as the administrative agent for the lenders, Societe Generale, as the syndication agent for the lenders, Mizuho Financial Group, Credit Lyonnais, New York Branch, The Royal Bank of Scotland PLC, and Deutsche Bank Ag New York Branch, as co-documentation agents, and certain commercial lending institutions, as lenders (filed as Exhibit 10.20 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2001 and incorporated herein by reference).
10.19	--	364-day Credit Agreement dated as of November 27, 2002 among the Registrant, as borrower, JPMorgan Chase Bank, as the administrative agent for the lenders, Wachovia Bank, National Association, as the syndication agent for the lenders, Societe Generale, Citibank, N.A., Deutsche Bank Ag New York Branch, and The Royal Bank of Scotland PLC, as co-documentation agents, and certain commercial lending institutions, as lenders, filed herewith.
21	--	Subsidiaries, filed herewith
23	--	Consent of KPMG LLP, filed herewith
99.1	--	Certification of the Company's Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)
99.2	--	Certification of the Company's Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)

* Management contract or compensatory plan or arrangement required to be filed as an exhibit hereto.

** Copies of exhibits will be furnished upon prepayment of 25 cents per page. Requests should be addressed to the Senior Vice President, Chief Financial Officer and Treasurer, Noble Energy, Inc., 350 Glenborough Drive, Suite 100, Houston, Texas 77067.