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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2004

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)
100 Glenborough Drive, Suite 100 **Houston, Texas**	**77067**
(Address of principal executive offices)	(Zip Code)

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

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 ☒ 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. ☒

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ☒ No ☐

Aggregate market value of Common Stock held by nonaffiliates as of June 30, 2004: **$2,590,000,000.**
Number of shares of Common Stock outstanding as of February 25, 2005: **59,043,952.**

DOCUMENT INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2005 Annual Meeting of Stockholders to be held on April 26, 2005, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2004, are incorporated by reference into Part III.

TABLE OF CONTENTS

PART I.

Item 1. Business

- General
- Current Developments
- Crude Oil and Natural Gas
  - Exploration, Exploitation and Development Activities
  - Production Activities
  - Acquisitions of Oil and Gas Properties, Leases and Concessions
  - Dispositions of Oil and Gas Properties
  - Marketing
  - Regulations and Risks
  - Competition
- Unconsolidated Subsidiaries
- Geographical Data
- Employees
- Available Information

Item 2. Properties

- Offices
- Crude Oil and Natural Gas

Item 3. Legal Proceedings

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

- Executive Officers of the Registrant

PART II.

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Item 5c. Stock Repurchases

Item 6. Selected Financial Data

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

Item 7a. Quantitative and Qualitative Disclosures About Market Risk

Item 8. Financial Statements and Supplementary Data

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

Item 9a. Controls and Procedures

Item 9b. Other Information

PART III.

Item 10. Directors and Executive Officers of the Registrant

Item 11. Executive Compensation

Item 12. Security Ownership of Certain Beneficial Owners and Management

Item 13. Certain Relationships and Related Transactions

Item 14. Principal Accounting Fees and Services

PART IV.

Item 15. Exhibits

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"), formerly known as Noble Affiliates, Inc., is a Delaware corporation that has been publicly traded on the New York Stock Exchange ("NYSE") since 1980. Noble Energy has been engaged, directly or through its subsidiaries, in the exploration, production and marketing of crude oil and natural gas since 1932, when Noble Energy's predecessor, Samedan Oil Corporation ("Samedan"), was organized. Noble Energy was organized in 1969 under the name "Noble Affiliates, Inc." and was Samedan's parent entity until Samedan was merged into Noble Energy effective December 31, 2002. The Company is noted for its innovative methods of marketing its international natural gas reserves through projects such as its methanol plant in Equatorial Guinea and its natural gas-to-power project (the "Machala Power Plant") in Ecuador.

In this report, unless otherwise indicated or the context otherwise requires, the "Company" or the "Registrant" refers to Noble Energy and its subsidiaries. Effective December 31, 2001, Energy Development Corporation ("EDC"), a previously wholly-owned subsidiary of Samedan, was merged into Samedan, another previously wholly-owned subsidiary. Effective December 31, 2002, Samedan was merged into Noble Energy. 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").

NEMI, a wholly-owned subsidiary, 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(s)	Barrel(s)
MBbls	Thousand barrels
Bpd	Barrels per day
Bopd	Barrels oil per day
MMBbls	Million barrels
MBpd	Thousand barrels per day
MMBpd	Million barrels per day
MBopd	Thousand barrels oil per day
MMBopd	Million barrels oil per day
BOE	Barrels oil equivalent
Boepd	Barrels oil equivalent per day
MMBoe	Million barrels oil equivalent
MMBoepd	Million barrels oil equivalent per day
$MM	Millions of dollars
Kwh	Kilowatt hours
MW	Megawatt
MWH	Megawatt hours
Mcf	Thousand cubic feet
Mcfpd	Thousand cubic feet per day
Mcfe	Thousand cubic feet equivalent
MMcf	Million cubic feet
MMcfepd	Million cubic feet equivalent per day
MMcfpd	Million cubic feet per day
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
Bcfepd	Billion cubic feet equivalent per day
Bcfpd	Billion cubic feet per day
BTU	British thermal unit
BTUpcf	British thermal unit per cubic foot
MMBTU	Million British thermal units
MMBTUpd	Million British thermal units per day
MTpd	Metric tons per day
LPG	Liquefied petroleum gas
LNG	Liquefied natural gas

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

Current Developments

Pending Merger with Patina Oil & Gas Corporation

On December 15, 2004, the Boards of Directors of Noble Energy and Patina Oil & Gas Corporation ("Patina") approved Noble Energy's merger (the "Merger Agreement") with Patina. As a result of the proposed merger, Patina will merge into a wholly-owned subsidiary of Noble Energy, and Patina shareholders will receive aggregate consideration comprised of approximately 60 percent Noble Energy common stock and 40 percent cash. Total consideration for the outstanding shares of Patina is fixed at approximately $1.1 billion in cash and approximately 27 million Noble Energy shares, not including options and warrants exchanged in the transaction, and subject to adjustment as provided in the Merger Agreement. Under the terms of the Merger Agreement, Patina shareholders will have the right to elect to receive either cash or Noble Energy common stock, or a combination thereof, in exchange for their shares of Patina common stock, subject to an allocation mechanism if either the cash election or the stock election is oversubscribed. While the per share consideration was initially set in the Merger Agreement at $37.00 in cash or .6252 shares of Noble Energy common stock, the per share consideration is subject to adjustment upwards or downwards. This adjustment will reflect 37.5126 percent of the difference between $59.18 and the price of Noble Energy's shares during a specified period prior to closing. In addition, the per share consideration is adjusted so that each Patina share receives consideration representing equal value regardless of whether it is converted into cash or Noble Energy common stock. The proposed merger is subject to the approval of the shareholders of Patina and Noble Energy and other customary conditions. The proposed merger is expected to be completed in the second quarter of 2005.

For more information regarding the proposed merger between Noble Energy and Patina, please refer to the joint proxy statement/prospectus of Noble Energy and Patina that is included in the registration statement on Form S-4 filed by Noble Energy with the United States Securities and Exchange Commission ("SEC") on January 25, 2005. This proxy statement/prospectus contains important information about the proposed merger. These materials are not yet final and will be amended. Investors and security holders of Noble Energy and Patina are urged to read the joint proxy statement/prospectus filed, and any other relevant materials filed by Noble Energy or Patina because they contain, or will contain, important information about Noble Energy, Patina and the proposed merger. The preliminary materials filed on January 25, 2005, the definitive versions of these materials and other relevant materials (when they become available) and any other documents filed by Noble Energy or Patina with the SEC, may be obtained for free at the SEC's website at *www.sec.gov*. In addition, the documents filed with the SEC by Noble Energy may be obtained free of charge from Noble Energy's website at *www.nobleenergyinc.com*. The documents filed with the SEC by Patina may be obtained free of charge from Patina's website at *www.patinaoil.com*.

Crude Oil and Natural Gas

Noble Energy 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. Exploration activities include geophysical and geological evaluation and exploratory drilling on properties for which the Company has exploration rights. 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 and Texas); the Mid-continent Region (Oklahoma and Kansas); and the Rocky Mountain Region (Colorado, Montana, Nevada, Wyoming and California). The international areas of operations include Argentina, China, Ecuador, Equatorial Guinea, the Mediterranean Sea (Israel) and the North Sea (the Netherlands and the United Kingdom). 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 Gulf of Mexico deepwater areas, and away from the Gulf of Mexico's conventional shallow shelf, in order to take advantage of potentially larger prospect sizes. The Company's current offshore production is derived from 157 gross wells operated by Noble Energy and 175 gross wells operated by others. At December 31, 2004, the Company held offshore federal leases covering 704,329 gross developed acres and 749,167 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 and Texas. The Mid-continent Region covers Oklahoma and Kansas. Properties in the Rocky Mountain Region are located in Colorado, Montana, Nevada, Wyoming and California.

Noble Energy's current onshore production is derived from 1,396 gross wells operated by the Company and 511 gross wells operated by others. At December 31, 2004, the Company held 645,275 gross developed acres and 352,664 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.

Domestic Division. On August 30, 2004, Noble Energy announced that the Company had combined the operations of its U.S. onshore and offshore divisions to create a single domestic division.

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. At December 31, 2004, the Company held 113,325 gross developed acres and 2,341,884 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 a concession offshore in the southern portion of Bohai Bay. At

December 31, 2004, the Company held 7,413 gross developed acres and no gross undeveloped acres in China. 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 natural gas properties in Ecuador since 1996. The Company is currently utilizing the natural gas from the Amistad 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. With current generating capacity of 130 MW of electricity, additional capital investment for combined cycle and a third turbine could ultimately increase the power plant’s capacity to generate approximately 300 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 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.

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. Production from the Alba field consists of 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 contract, which runs through 2026, to purchase natural gas from the Alba field. The plant is owned by Atlantic Methanol Production Company, LLC (“AMPCO”), in which the Company owns a 45 percent interest through its ownership interest in Atlantic Methanol Capital Company (“AMCCO”). For more information on the methanol plant, see “Item 1. Business—Unconsolidated Subsidiaries” of this Form 10-K.

In 2004, Noble Energy entered into an additional natural gas contract, which runs through 2023, with an LNG plant. Noble Energy does not hold an interest in the LNG plant. The Company has recorded reserves based on minimum contractual volumes required to be taken under the LNG agreement.

At December 31, 2004, the Company held 45,203 gross developed acres and 1,112,841 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 three licenses and two leases. At December 31, 2004, the Company held 123,552 gross developed acres and 292,572 gross undeveloped acres located about 20 miles offshore Israel in water depths ranging from 700 feet to 5,000 feet. On December 24, 2003, Noble Energy and its partners announced the commencement of production of natural gas from its Mari-B field. Sales of natural gas to The Israel Electric Corporation Limited (“IEC”) began in February 2004 under a definitive agreement executed in June 2002. In September 2004, the Company entered into a separate agreement to provide natural gas for use in the Bazan Refinery located in Ashdod, Israel. Sales to Bazan are expected to commence during the third quarter of 2005. 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 (the Netherlands and the United Kingdom) since 1996. At December 31, 2004, the Company held 42,723 gross developed acres and 540,310 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. In December 2003, Noble Energy elected not to pursue any additional exploration efforts in the Nam Con Son Basin of Vietnam. As a result, the Company wrote off its investment in Vietnam and its ownership in two blocks.

Production Activities

Revenues from sales of crude oil, natural gas and gathering, marketing and processing (“GMP”) have accounted for approximately 90 percent or more of consolidated revenues for each of the last three fiscal years.

Operated Property Statistics. The percentage of properties operated by the Company indicates the amount of control over timing of operations. The percentage of operated crude oil and natural gas wells on both the well count and percentage of sales volume basis are shown in the following table as of December 31:

	2004		2003		2002	
(in percentages)	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**
Operated well count basis	18.2	59.2	19.6	60.1	23.3	62.8
Operated sales volume basis	29.1	57.9	33.3	48.8	29.3	45.1

Non-operated Property Statistics. The percentage of non-operated crude oil and natural gas wells on both the well count and the percentage of sales volume basis are shown in the following table as of December 31:

	2004		2003		2002	
(in percentages)	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**
Non-operated well count basis	81.8	40.8	80.4	39.9	76.7	37.2
Non-operated sales volume basis	70.9	42.1	66.7	51.2	70.7	54.9

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

	2004	2003	2002
Crude oil production (MMBbls)	16.6	13.1	10.6
Natural gas production (Bcf)	134.3	122.9	124.5

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, including royalty, from continuing operations, for the three years ended December 31:

	2004	2003	2002
Total crude oil equivalents (MMBoe)	39.0	33.6	31.4
Total natural gas equivalents (Bcfe)	234.0	201.7	188.2

Acquisitions of Oil and Gas Properties, Leases and Concessions

During 2004, Noble Energy spent approximately $85.8 million on the purchase of proved crude oil and natural gas properties. The Company spent approximately $1.3 million in 2003 and $8.0 million in 2002 on the acquisition of proved crude oil and natural gas properties. For more information, see “Item 2. Properties—Crude Oil and Natural Gas” of this Form 10-K.

During 2004, Noble Energy spent approximately $44.7 million on acquisitions of unproved properties. The Company spent approximately $10.2 million in 2003 and $30.5 million in 2002 on acquisitions of unproved properties. These properties were acquired 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.

Dispositions of Oil and Gas Properties

During 2004, the Company completed its asset disposition program announced in July 2003. The sales price for the five packages of properties, before closing adjustments, totaled approximately $130 million. The properties held for disposition were reported as discontinued operations. The estimated reserves associated with these five packages were 24.2 MMBoe.

Marketing

NEMI seeks opportunities to enhance the value of the Company's domestic natural gas production by marketing directly to end-users and aggregating natural gas to be sold to natural gas marketers and pipelines. During 2004, approximately 79 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 production 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 long-term natural gas sales contract with NEMI, whereby the Company is paid an index price for all natural gas sold to NEMI. The contract does not specify scheduled quantities or delivery points and expires on May 31, 2009. The Company sold approximately 56 percent of its natural gas production to NEMI in 2004. NEMI's revenues from sales of natural gas, including related derivative transactions, less cost of goods sold, are reported in GMP. 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 with third parties representing approximately 12 percent of its 2004 natural gas sales.

Substantial competition in the natural gas marketplace continued in 2004. The Company's average natural gas price from continuing operations, inclusive of the impact of commodity derivatives, increased $.61 from $4.13 per Mcf in 2003 to $4.74 per Mcf in 2004. Due to the volatility of natural gas prices, the Company has used derivative instruments and may do so in the future as a means of controlling its exposure to commodity 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.

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 42 percent of the Company's crude oil production as well as certain third-party crude oil. The Company records all of NEMI's revenues from sales of crude oil, less cost of goods sold, as GMP. 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 from continuing operations, inclusive of the impact of commodity derivatives, increased $6.81 from $27.72 per Bbl in 2003 to $34.53 per Bbl in 2004. Due to the volatility of crude oil prices, the Company has used derivative instruments and may do so in the future as a means of controlling its exposure to commodity 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 2004 accounted for approximately 24 percent of the Company's crude oil sales, representing approximately 10 percent of total revenues. The five largest purchasers accounted for approximately 68 percent of total crude oil sales. The largest single non-affiliated purchaser of the Company's natural gas production in 2004 accounted for approximately eight percent of its natural gas sales, representing approximately four percent of total revenues. The five largest purchasers accounted for approximately 24 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, among others, 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 such a release or discharge, subject to certain specified limitations on liability, may be 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 hazardous substances that have 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 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, 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 that include directors and officers liability, general liability, well control, pollution, terrorism acts, physical damage insurance and business interruption insurance for certain international locations. The Company self-insures, is a shareholder in an industry mutual insurance company and purchases policies from third party insurance providers to cover various risks. 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. 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 Subsidiaries

AMCCO, AMPCO, AMPCO Marketing LLC, AMPCO Services LLC and Samedan Methanol are accounted for using the equity method. The Company owns a 45 percent interest in AMPCO through its 50 percent ownership in AMCCO. AMPCO completed construction of a methanol plant in Equatorial Guinea in the second quarter of 2001.

The plant construction started during 1998, and initial production of commercial grade methanol commenced May 2, 2001. 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 of natural gas from the Alba field in which Noble Energy owns a 34 percent interest. The methanol plant has a contract, which runs through 2026, to purchase natural gas from the Alba field. The Company's investment in the methanol plant is included in investment in unconsolidated subsidiaries on the Company's balance sheets, and the Company's share of earnings from its unconsolidated subsidiaries is reported in the revenue section of the Company's statements of operations as income from unconsolidated subsidiaries. For more information, see “Item 8. Financial Statements and Supplementary Data—Note 13 - Unconsolidated Subsidiaries” 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 crude oil and natural gas exploration, exploitation and production: United States, Equatorial Guinea, North Sea, Israel, and Other International, Corporate and Marketing. For more information, see “Item 8. Financial Statements and Supplementary Data—Note 15 - Geographical Data” of this Form 10-K.

Employees

The total number of employees of the Company decreased during the year from 583 at December 31, 2003 to 559 at December 31, 2004. In addition, 173 foreign nationals worked in Noble Energy offices in China, Ecuador, Equatorial Guinea, Israel and the United Kingdom as of December 31, 2004.

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, Forms 3, 4 and 5 filed on behalf of directors and officers and amendments to those reports as soon as reasonably practicable after such materials are electronically filed with or furnished to the SEC.

Also posted on the Company’s website, and available in print upon request of any stockholder to the Investor Relations Department, are charters for the Company’s Audit Committee; Compensation, Benefits and Stock Option Committee; Corporate Governance and Nominating Committee; and Environment, Health and Safety Committee. Copies of the Code of Business Conduct and Ethics, and the Code of Ethics for Chief Executive and Senior Financial Officers governing our directors, officers and employees (the “Codes”) are also posted on the Company’s website under the “Corporate Governance” section. Within the time period required by the SEC and the NYSE, as applicable, the Company will post on its website any modifications to the Codes and any waivers applicable to senior officers as defined in the applicable Code, as required by the Sarbanes-Oxley Act of 2002 (“Sarbanes-Oxley”).

In 2004, the Company submitted the annual certification of its Chief Executive Officer regarding the Company’s compliance with the NYSE’s corporate governance listing standards, pursuant to Section 303A.12(a) of the NYSE Listed Company Manual. A supplemental certification was delivered subsequently to the NYSE following the unexpected death of one of the Company’s independent directors.

Item 2. Properties.

For crude oil and natural gas reserve information, see “Item 8. Financial Statements and Supplementary Data—Supplemental Oil and Gas Information” of this Form 10-K.

Offices

The principal corporate office of the Company is located in Houston, Texas. The Company maintains offices for domestic and international operations in Houston, Texas. The Company also maintains offices in China, Ecuador, Equatorial Guinea, Israel and the United Kingdom. NEMI’s office is located in Houston, Texas. The Company also maintains an office in Ardmore, Oklahoma for centralized accounting, division orders, employee benefits, information technology and related administrative functions.

Crude Oil and Natural Gas

The Company 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 2004, Noble Energy drilled or participated in the drilling of 225 gross (108.8 net) wells, comprised of 95 gross (18.6 net) international wells and 130 gross (90.2 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. During 2004, Noble Energy's offshore drilling program included 19 gross (8.1 net) exploration and development wells. Of the wells drilled in 2004, 10 wells, or 53 percent, were commercial discoveries, seven wells were exploratory dry holes and two were development dry holes.

Viosca Knoll Block 917, 961 and 962 ("Swordfish"), a 2001 deepwater discovery, is located in approximately 4,500 feet of water. During 2004, Noble Energy acquired all of BP Exploration & Production, Inc.'s 50 percent working interest, increasing the Company's working interest from 10 percent to 60 percent. Two well penetrations found crude oil and natural gas pay in multiple, high-quality reservoirs. During 2005, the three wells will be connected to existing infrastructure through subsea tiebacks. Production is expected to commence in the second quarter of 2005 at an initial rate of approximately 10,000 Boepd, net to Noble Energy. The Company recorded net reserves of 9.6 MMBoe in 2004.

Green Canyon 199 ("Lorien"), a July 2003 deepwater crude oil discovery, is located in approximately 2,200 feet of water. During 2004, Noble Energy acquired an additional interest in Lorien from ConocoPhillips. The acquisition increased the Company's working interest from 20 percent to 60 percent and Noble Energy now operates the block. The discovery well was drilled to a total measured depth of 18,703 feet (or a total vertical depth of 17,432 feet) and encountered more than 120 feet of net pay, primarily crude oil. A successful appraisal sidetrack well was drilled in 2004 and a second appraisal well will be drilled in the first quarter of 2005. Both wells will be completed and tied back to area infrastructure during late 2005 or early 2006. Production is expected to commence in the first half of 2006 at an initial rate of approximately 12,000 Boepd, net to Noble Energy. The Company did not record any reserves on this property in 2004.

Green Canyon 768 ("Ticonderoga"), a 2004 deepwater crude oil discovery, is located near Kerr-McGee's Constitution development on Green Canyon Block 680 and will be a subsea tieback to the planned Constitution spar. The Ticonderoga well spud on March 21, 2004 and is located in approximately 5,300 feet of water. The well drilled to a total measured depth of 13,556 feet (or a total vertical depth of 13,370 feet). The well encountered over 250 feet of net high-quality pay, primarily crude oil. The Company recorded net reserves of 15.9 MMBoe in 2004 from this discovery. Production is expected to commence by mid-2006 at an initial rate of approximately 10,000 to 12,000 Boepd, net to Noble Energy. The Company has a 50 percent working interest.

Noble Energy increased its working interest in the Eugene Island 254 field from 30 percent to 100 percent. After completing a successful two-well program, consisting of sidetracking and completing one well and recompleting another well, production was re-established in the field in November 2004 at a producing net rate of 1,300 Boepd.

Noble Energy was the successful bidder, alone or with partners, on 24 of 26 lease blocks at the Central Gulf of Mexico Outer Continental Shelf (the "Shelf") Sale 190. On the Shelf, the Company bid on 24 lease blocks and was the high bidder on 22 lease blocks. All of the 22 blocks on which Noble Energy was the high bidder contain deep objectives below 15,000 feet. In the deepwater, the Company was the high bidder on two blocks. Net to the Company's interest, the high bids totaled approximately $6.1 million. Noble Energy concentrated its bids on opportunities in the West Cameron, Chandeleur Sound and Mobile areas.

Domestic Onshore. During 2004, Noble Energy's onshore drilling program included 111 gross (82.1 net) exploration and development wells. Of the wells drilled in 2004, 94 wells, or 85 percent, were commercial discoveries and 17 wells were dry holes. Of the 17 dry holes, nine were exploratory and expensed.

Activity in the onshore Gulf Coast region in 2004 remained high with 31 wells drilled, of which 24, or 77 percent, were successful. The majority of Noble Energy's onshore exploration focus in 2004 was in the Gulf Coast region, where 15 out of 22 exploration wells were successfully completed.

In Duval County, Texas, Noble Energy drilled 10 wells, of which eight were successful. The prospects were identified with proprietary 3-D seismic acquired in late 2002. The eight successful wells were producing 2,930 Boepd, gross, at year-end 2004. Noble Energy's working interests in the wells drilled in 2004 range from 85 percent to 100 percent.

During the year, the Company's onshore development activity was focused in the Mid-continent and Rockies regions where 69 out of 77 development wells were successfully completed.

In the Niobrara Trend of northeast Colorado, results of infill drilling pilot programs were used to obtain area-wide regulatory approval for 40-acre development of the Niobrara formation. As a result of the regulatory approval that was granted late in the year, Noble Energy initiated an aggressive development drilling program. The Company plans to drill up to 235 Niobrara development wells in 2005.

Another rapidly growing area is the Piceance Basin in western Colorado. Noble Energy was successful in acquiring approximately 7,000 acres in the Piceance Basin in 2004 and began drilling several wells late in the year. The program is expected to continue in 2005.

Argentina. Noble Energy participated with a 13 percent working interest in 77 development wells in the El Tordillo field during 2004. The Company has been awarded, and is awaiting final government approval on, an operated crude oil and natural gas exploration permit of approximately 1.2 million acres. The permit is located adjacent to an existing permit of approximately 1.2 million acres in the Cuyo Basin of Mendoza Province in western Argentina.

China. Noble Energy, as operator, has a 57 percent working interest in the Cheng Dao Xi ("CDX") field, which is located on the south side of Bohai Bay off the coast of China. Initial production from CDX commenced on January 13, 2003. During 2004, CDX averaged 3,883 Bopd net to Noble Energy.

Noble Energy continued its development of the CDX field with a successful drilling program in 2004. The results increased production above 5,000 Bopd net to Noble Energy at the end of 2004. The Company plans to drill two additional development wells in 2005.

Ecuador. In September 2002, Noble Energy commenced operations of its 100 percent-owned integrated natural gas-to-power project. The project includes the Amistad field, which is located in the shallow waters of the Gulf of Guayaquil near the coast of Ecuador. The power plant is located on the coast near Machala, Ecuador and connects to the Amistad field via a 40-mile pipeline. The Machala Power Plant is the only natural gas-fired commercial power generator in Ecuador and currently has a generating capacity of 130 MW of electricity from twin General Electric Frame 6Fa turbines. In 2004, the Company implemented a successful drilling program in the Amistad field that is projected to provide plant feedstock into the next decade.

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. The Phase 2A project included adding two platforms, 12 wells, three pipelines and two compressors. Initial startup of Phase 2A began in November 2003. The Phase 2A expansion is expected to increase condensate production by approximately 8,400 Bpd net to Noble Energy.

Phase 2B, which is scheduled to be completed during 2005, is expected to increase production of LPG by approximately 3,900 Bpd net to Noble Energy and condensate production by approximately 1,800 Bpd net to Noble

Energy. This project includes increasing processing capacity, storage and offloading facilities at the existing LPG plant.

Following the ramp-up of Phase 2A in 2005 and the completion of Phase 2B, condensate and LPG capacity will be approximately 15,800 Bpd net to Noble Energy and 4,700 Bpd net to Noble Energy, respectively.

Noble Energy, through its subsidiaries, holds a 34 percent working interest in the offshore Alba field and related condensate production facilities, a 28 percent interest in the Alba LPG plant and a 45 percent interest in the AMPCO plant. The AMPCO plant purchases and processes approximately 125 MMcfpd of natural gas into 2,500 MTpd of methanol.

In 2004, Noble Energy signed a Production Sharing Contract ("PSC") with the Republic of Equatorial Guinea covering Block "O" offshore Bioko Island and acquired an interest in a PSC for Block "I", also located offshore Bioko Island. Under the terms of these agreements, Noble Energy will be Technical Operator with a 45 percent working interest in Block "O" and a 40 percent working interest in Block "I". Exploration drilling is expected to begin in 2005 on Block "O".

Israel. The Company and its partners have an agreement to provide approximately 170 MMcfpd of natural gas for use in IEC's power plants. In September 2004, the Company entered into a separate agreement to provide approximately 11 MMcfpd of natural gas for use in the Bazan Refinery located in Ashdod, Israel. Natural gas is produced from the Mari-B field, which was discovered in 2000, offshore Israel. Sales to IEC commenced February 18, 2004 and sales to Bazan are expected to commence during the third quarter of 2005. Noble Energy has a 47 percent working interest in the Mari-B field. During 2004, the Mari-B field averaged 48 MMcfpd net to Noble Energy. The Company has two additional discoveries offshore Israel, which are planned to be subsea tied into the Mari-B platform.

North Sea. The Company continued to focus on production and exploration growth in 2004 and added reserves in producing fields. The Company participated in two successful non-operated appraisal wells in the U.K. sector of the North Sea, one of which is expected to lead to the development of the Dumbarton field during 2005 and 2006. The Company also participated in drilling an exploratory dry hole in the Danish sector, the license for which has been subsequently relinquished.

During the year, the Company entered into an exchange agreement with Talisman Energy (UK) Limited whereby the Company disposed of its interests in the producing Buchan and Hannay fields and the Tweedsmuir development project in exchange for a producing interest in the MacCulloch field and cash.

Net Exploratory and Development 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			
Year Ended	Productive(1)		Dry(2)		Productive(1)		Dry(2)	
December 31,	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l
2004	10.70	.30	8.45	1.05	62.37	17.25	8.73	
2003	10.84	.07	12.40	2.67	25.10	7.32	8.16	
2002	9.78		11.45	3.27	41.53	12.84	11.17	

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

(2) A dry hole is an exploratory or development well determined 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, 2005, Noble Energy was drilling 3 gross (1.1 net) exploratory wells and 13 gross (5.7 net) development wells. These wells are located onshore in Colorado, Louisiana, Montana, Oklahoma, Texas, Argentina and offshore Equatorial Guinea and the Gulf of Mexico. These wells have objectives ranging from approximately 1,700 feet to 25,000 feet. The drilling cost to Noble Energy of these wells will be approximately $13.9 million if all are dry and approximately $18.2 million if all are completed as producing wells.

Crude Oil and Natural Gas Wells. Due to the various asset dispositions in 2003 and 2004, there was a significant decrease from 2002 in the number of wells in which Noble Energy held an interest. The number of productive crude oil and natural gas wells in which Noble Energy held an interest as of December 31 follows:

	2004(1)(2)		2003(1)(2)		2002(1)(2)	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil Wells						
United States – Onshore	179.0	105.9	196.0	118.2	1,131.0	458.7
United States – Offshore	165.0	109.2	186.0	114.2	232.0	95.7
International	713.0	98.6	716.0	88.8	687.0	81.3
Total	1,057.0	313.7	1,098.0	321.2	2,050.0	635.7
Natural Gas Wells						
United States – Onshore	1,728.0	1,121.5	1,645.0	1,042.1	1,603.0	1,006.6
United States – Offshore	167.0	73.5	299.0	116.5	265.0	184.9
International	28.0	10.3	34.0	8.4	42.0	13.1
Total	1,923.0	1,205.3	1,978.0	1,167.0	1,910.0	1,204.6

(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.

	2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Multiple Completions						
Crude Oil	7.0	4.6	9.0	5.8	12.0	6.0
Natural Gas	20.0	8.1	29.0	11.3	28.0	8.9
Not Producing (Shut-in)						
Crude Oil	516.0	102.5	573.0	109.2	565.0	212.3
Natural Gas	297.0	127.2	337.0	142.5	121.0	73.0

At year-end 2004, Noble Energy had less than 16 percent of its crude oil and natural gas sales volumes, on an Mcfe basis, committed to long-term supply contracts and had no similar agreements with foreign governments or authorities.

Since January 1, 2004, 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.

SEC guidelines do not limit reserve bookings to only contracted volumes if it can be demonstrated that there is reasonable certainty that a market exists. The Company has booked reserves in excess of contracted volumes for Israel due to the reasonable certainty of the existence of markets in future periods. In Israel, the Company has a natural gas contract with IEC, which is expected to run through 2014, and a contract with the Israel Bazan Refinery through the year 2015. The Israeli natural gas market, as estimated by the Israeli Ministry of National Infrastructure, from 2005 to 2020, is significantly greater than Noble Energy's uncontracted net estimated proved reserves.

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 from continuing operations.

	Year Ended December 31, 2004	2003	2002
Average sales price per Bbl of crude oil (1):			
United States	$ 31.90	$ 26.21	$ 23.29
International	$ 36.94	$ 28.94	$ 24.98
Combined (2)	$ 34.53	$ 27.72	$ 24.22
Average sales price per Mcf of natural gas (1):			
United States	$ 6.00	$ 4.75	$ 3.24
International (3)	$ 1.88	$ 1.17	$ 1.18
Combined (4)	$ 4.74	$ 4.13	$ 2.89
Average production cost per BOE (5):			
United States	$ 5.46	$ 4.43	$ 3.76
International	$ 4.99	$ 5.40	$ 4.16
Combined	$ 5.27	$ 4.78	$ 3.88

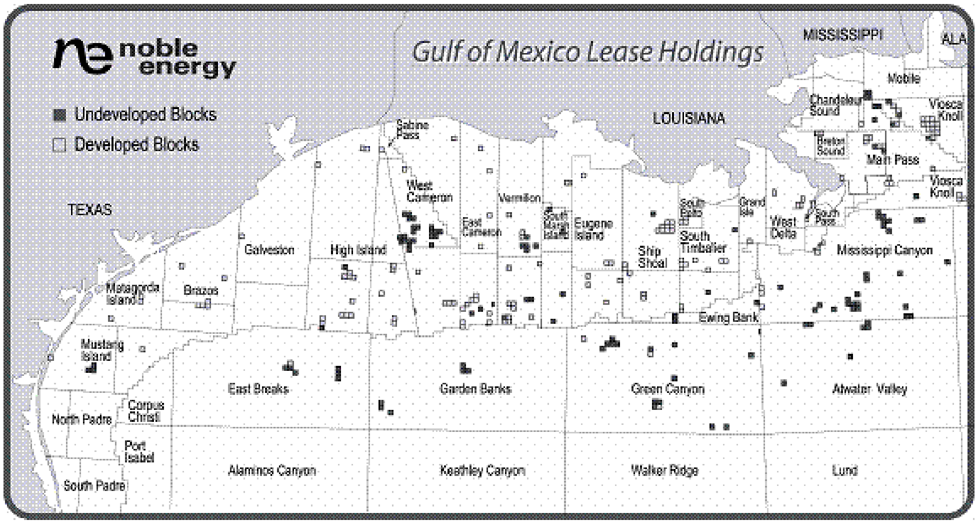
(1) Includes royalties.

(2) Reflects a reduction of $3.05 per Bbl in 2004, $1.01 per Bbl in 2003 and $.02 per Bbl in 2002 from hedging in the United States.

(3) Ecuador natural gas revenues and natural gas production volumes are excluded in the calculation of the International average sales price per Mcf of natural gas. The natural gas-to-power project in Ecuador is 100 percent owned by Noble Energy. Intercompany natural gas sales are eliminated for accounting purposes.

(4) Reflects a reduction of $.08 per Mcf in 2004 and $.44 per Mcf in 2003 and an increase of $.05 per Mcf in 2002 from hedging in the United States.

(5) Oil and gas production costs include lease operating expense, production taxes, ad valorem taxes, workover expense and transportation costs.



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

Block	Working Interest (%)
East Breaks	
464 *	48
465 *	48
475 *	100
510 *	33
519 *	100
563 *	100
Green Canyon	
85 *	50
142	100
185 *	100
186 *	100
187 *	100
199 *	60
228 *	100
238 *	40
303 *	40
507 *	50
723 *	100
724 *	100
767 *	50
955 *	7
958 *	25
East Cameron	
342	50
348	30
355	100
South Timbalier	
62	100
278	50
Ship Shoal	
73	50
Mustang Island	
829	50
830	50
831	60
Vermilion	
208	25
227	50
228	50

230	100
235	100
352	100
353	100
391	100
Garden Banks	
25	50
416 *	100
460 *	100
461 *	100
751 *	100
795 *	100
841 *	39
Main Pass	
107	25
110	25
South Marsh Island	
4	100
38	100
145	100
195	50
Viosca Knoll	
23	100
65	100
157	100
383	24
908 *	100
Mississippi Canyon	
26 *	75
70 *	75
71 *	75
115 *	75
116 *	100
122 *	75
123 *	75
159 *	75
204 *	100
524 *	50
595 *	24
602 *	75
639 *	24
665 *	50
769 *	100
811 *	30
849 *	34
855 *	30
856 *	30
857 *	30
892 *	35
896 *	67
900 *	30
901 *	30
911 *	40
999 *	30
1000 *	30
Chandeleur Sound	
1	100
4	100
18	100
39	100
Mobile	
942	100
943	100
987	100
Ewing Bank	
834 *	14
949	52

993	53
High Island	
A-218	100
A-230	100
A-422	100
A-587	3
Atwater Valley	
10 *	100
11 *	100
23 *	100
66 *	100
67 *	100
327 *	79
533 *	40
West Cameron	
359	100
360	100
372	100
373	100
389	100
392	100
393	100
400	100
404	100
405	100
406	100
411	100
412	100
418	100
419	100
420	100
421	100
422	50
423	100
438	100
443	100
446	100

*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, 2004, 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			2,926	505
California	812	333	25,459	8,181
Colorado	79,252	60,372	37,578	31,046
Kansas	92,956	52,627	21,604	14,222
Louisiana	31,030	10,709	29,613	11,498
Michigan			1,876	427
Mississippi	878	34	1,884	51
Montana	201,783	123,603	3,798	1,452
Nevada			61,076	60,031
New Mexico	1,797	897	2,200	1,613
North Dakota			685	314
Oklahoma	136,057	47,385	11,353	5,521
Texas	74,421	30,818	82,115	30,257
Utah	1,280	260	8,514	5,446
Wyoming	25,009	10,928	61,983	32,970
Total United States Onshore	645,275	337,966	352,664	203,534
United States Offshore (Federal Waters)				
Alabama	92,160	45,158	37,834	32,081
California	38,833	12,039	52,364	9,422
Louisiana	376,634	164,810	402,938	320,704
Mississippi	37,756	19,260	138,240	74,870
Texas	158,946	73,560	117,791	85,145
Total United States Offshore (Federal Waters)	704,329	314,827	749,167	522,222
International				
Argentina	113,325	15,548	2,341,884	2,341,884
China	7,413	4,225		
Ecuador	12,355	12,355	851,771	851,771
Equatorial Guinea	45,203	15,727	1,112,841	481,291
Israel	123,552	58,142	292,572	137,681
Netherlands	865	130	74,749	11,212
United Kingdom	41,858	3,536	465,561	131,263
Total International	344,571	109,663	5,139,378	3,955,102
Total (5)	1,694,175	762,456	6,241,209	4,680,858

(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 one concession totaling 1,163,865 acres subject to final governmental approval.

(5) If production is not established, approximately 143,507 gross acres (88,350 net acres), 248,777 gross acres (127,235 net acres) and 91,175 gross acres (71,700 net acres) will expire during 2005, 2006 and 2007, respectively.

Item 3. Legal Proceedings.

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.

On October 15, 2002, Noble Gas Marketing, Inc. and Samedan Oil Corporation, 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 $12 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 at issue.

On January 13, 2003, the Noble Defendants filed an answer to ENA's complaint. On January 29, 2003, the Noble Defendants filed the Motion of Noble Energy Marketing, Inc., as Successor to Noble Gas Marketing, Inc., and Noble Energy, Inc., as Successor to Samedan Oil Corporation, to Compel Arbitration. On March 4, 2003, the Court issued its Order Governing Mediation of Trading Cases and Appointing the Honorable Allan L. Gropper as Mediator (the "Mediation Order") which, among other things, abated this case and referred it to mediation along with other pending adversary proceedings in the Enron bankruptcy cases which involve disputes arising from or in connection with commodity trading contracts. Pursuant to the Mediation Order, the Honorable Allan L. Gropper (United States Bankruptcy Judge for the Southern District of New York) has acted as mediator for this case and the other trading cases which have been referred to him. Mediation sessions for this case were held on December 17, 2003 and May 21, 2004. In January 2005, the parties reached a preliminary settlement of matters in dispute subject to the approval of ENA's internal committees, the board of directors of Enron Corp., and the United States Bankruptcy Court. The proposed settlement, if approved, will not have a material adverse effect on the Company's consolidated financial position, results of operations or liquidity. The Company was adequately reserved for this settlement and there will be no resulting gain or loss.

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

There were no matters submitted to a vote of security holders during the fourth quarter of 2004.

Executive Officers of the Registrant

The following table sets forth certain information, as of March 14, 2005, with respect to the executive officers of the Registrant.

Name	Age	Position
Charles D. Davidson (1)	55	Chairman of the Board, President, Chief Executive Officer and Director
Alan R. Bullington (2)	53	Senior Vice President, International
Robert K. Burleson (3)	47	Senior Vice President, Business Administration and President, Noble Energy Marketing, Inc.
Susan M. Cunningham (4)	49	Senior Vice President, Exploration
Arnold J. Johnson (5)	49	Vice President, General Counsel and Secretary
James L. McElvany (6)	51	Senior Vice President
William A. Poillion, Jr. (7)	55	Senior Vice President, Production and Drilling
Ted A. Price (8)	45	Vice President, Domestic Onshore
David L. Stover (9)	47	Senior Vice President, Domestic and Business Development
Chris Tong (10)	48	Senior Vice President, Chief Financial Officer and Treasurer
Kenneth P. Wiley (11)	52	Vice President, Information Technology

(1) Charles D. Davidson was elected President and Chief Executive Officer of the Company in October 2000 and Chairman of the Board in 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 joined ARCO in 1972.

(2) Alan R. Bullington was elected a Senior Vice President of the Company on July 27, 2004. Prior thereto, he served as Vice President and General Manager, International Division of Samedan Oil Corporation beginning 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 Senior Vice President of the Company on July 27, 2004. Prior thereto, he served as Vice President of the Company since 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 was elected Senior Vice President of Exploration of the Company in April 2001. 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, appointed a Vice President in 1998 and responsible, in 1999, for Statoil's West Africa exploration efforts. She joined Amoco in 1980 as a geologist and served in exploration and development positions of increasing responsibility until 1997.

(5) Arnold J. Johnson was elected Vice President, General Counsel and Secretary of the Company on February 1, 2004. Prior thereto, he served as Associate General Counsel and Assistant Secretary of the Company from January 2001 through January 2004. Prior thereto, he served as Senior Counsel for BP America, Inc. from October 2000 to January 2001. Mr. Johnson held several positions as an attorney for Vastar and ARCO from March 1989 through September 2000, most recently as Assistant General Counsel and Assistant Secretary of Vastar from 1997 through 2000. He joined ARCO in 1980 as a landman and served in land management positions of increasing responsibility until 1989.

(6) James L. McElvany was elected Senior Vice President, Chief Financial Officer and Treasurer of the Company in July 2002 and served as such through December 31, 2004. He remains with the Company as Senior Vice President and will aid in the transition process until his retirement, which will occur in the second quarter of 2005. Prior to July 2002, 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) 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.

(8) Ted A. Price was elected Vice President of the Company on January 29, 2002 and currently serves as Vice President, Domestic Onshore. Previously, he served as Manager of Onshore Exploration since 1999. Mr. Price joined the Company in 1981 as a geologist.

(9) David L. Stover was elected Senior Vice President of Domestic and Business Development of the Company on July 27, 2004. Prior thereto, he served as the Company's Vice President of Business Development since 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, 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.

(10) Chris Tong succeeded Mr. McElvany as Senior Vice President, Chief Financial Officer and Treasurer of the Company effective January 1, 2005. Prior to January 1, 2005, he had served as Senior Vice President and Chief Financial Officer for Magnum Hunter Resources, Inc. since August 1997. Prior thereto, he was Senior Vice President of Finance of Tejas Acadian Holding Company and its subsidiaries including Tejas Gas Corp., Acadian Gas Corporation and Transok, Inc., all of which were wholly-owned subsidiaries of Tejas Gas Corporation. Mr. Tong held these positions since August 1996, and served in other treasury positions with Tejas beginning August 1989. From 1980 to 1989, Mr. Tong served in various energy lending capacities with several commercial banking institutions. Prior to his banking career, Mr. Tong also served over a year with Superior Oil Company as a Reservoir Engineering Assistant.

(11) Kenneth P. Wiley was elected Vice President-Information Technology of the Company in 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. There are no family relationships among any of the Registrant's officers.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Common Stock. The Registrant's Common Stock, $3.33 1/3 par value ("Common Stock"), is listed and traded on the NYSE 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 NYSE and quarterly dividends paid per share.

	High	Low	Dividends Per Share
2004			
First quarter	$ 48.47	$ 42.65	$ .05
Second quarter	$ 52.06	$ 43.61	$ .05
Third quarter	$ 58.82	$ 48.97	$ .05
Fourth quarter	$ 64.60	$ 56.62	$ .05
2003			
First quarter	$ 38.62	$ 33.07	$ .04
Second quarter	$ 40.02	$ 32.37	$ .04
Third quarter	$ 40.00	$ 35.37	$ .04
Fourth quarter	$ 45.99	$ 37.48	$ .05

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. Pursuant to the records of the transfer agent, as of February 25, 2005, the number of holders of record of Common Stock was 901. The following chart indicates the common stockholders by category.

February 25, 2005	Shares Outstanding
Individuals	254,546
Joint accounts	45,096
Fiduciaries	118,183
Institutions	64,948
Nominees	58,560,874
Foreign	305
Total-excluding treasury shares	59,043,952

Sales of Unregistered Securities. The Company owns a 45 percent interest in AMPCO through its 50 percent ownership in AMCCO. During 1999, AMCCO issued $125 million Series A-2 senior secured notes due December 15, 2004 to fund construction payments owed in connection with the construction of the methanol plant. These notes were included on the Company's balance sheet at December 31, 2003 and were repaid by the Company during 2004. The Company's investment in the methanol plant is included in investment in unconsolidated subsidiaries.

Item 5c. Stock Repurchases.

The Company did not repurchase any of its outstanding Common Stock during 2004.

Item 6. Selected Financial Data.

(in thousands, except per share amounts and ratios)	Year Ended December 31, 2004	2003	2002	2001	2000
Revenues and Income					
Revenues	$ 1,351,176	$ 1,005,950	$ 701,332	$ 794,588	$ 729,168
Income from continuing operations	313,850	89,892	8,095	85,163	137,066
Net income	328,710	77,992	17,652	133,575	191,597
Per Share Data					
Basic earnings per share:					
Income from continuing operations	$ 5.39	$ 1.58	$ 0.14	$ 1.51	$ 2.45
Net income	$ 5.64	$ 1.37	$ 0.31	$ 2.36	$ 3.42
Cash dividends	$ 0.20	$ 0.17	$ 0.16	$ 0.16	$ 0.16
Year-end stock price	$ 61.66	$ 44.43	$ 37.55	$ 35.29	$ 46.00
Basic weighted average shares outstanding	58,275	56,964	57,196	56,549	55,999
Financial Position (at year end)					
Property, plant and equipment, net:					
Oil and gas mineral interests, equipment and facilities	$ 2,332,950	$ 2,099,741	$ 2,139,785	$ 1,953,211	$ 1,485,123
Total assets	3,443,171	2,842,649	2,730,015	2,604,255	2,002,819
Long-term obligations:					
Long-term debt, net of current portion	880,256	776,021	977,116	961,118	648,567
Deferred income taxes	183,351	163,146	201,939	176,259	117,048
Asset retirement obligation	175,415	101,804			
Other deferred credits and noncurrent liabilities	79,157	80,176	69,820	75,629	61,639
Shareholders' equity	1,459,988	1,073,573	1,009,386	1,010,198	849,682
Ratio of debt-to-book capital (1)	.38	.46	.50	.50	.44

(1) Defined as the Company's total debt divided by the sum of total debt plus equity.

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

Operating Statistics – Continuing Operations

	Year Ended December 31, 2004	2003	2002	2001	2000
Natural Gas					
Sales (in millions)	$ 582.2	$ 457.6	$ 341.1	$ 487.4	$ 492.0
Production (MMcfpd)	367.0	336.6	341.0	355.6	335.8
Average realized price (per Mcf)	$ 4.74	$ 4.13	$ 2.89	$ 3.86	$ 4.09
Crude Oil					
Sales (in millions)	$ 565.3	$ 358.0	$ 252.3	$ 208.6	$ 124.9
Production (Bopd)	45,375	36,014	29,114	24,973	19,650
Average realized price (per Bbl)	$ 34.53	$ 27.72	$ 24.22	$ 23.49	$ 18.21
Royalty sales (in millions)	$ 26.7	$ 23.5	$ 15.6	$ 20.9	$ 17.3

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

Noble Energy 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 and Texas); the Mid-continent Region (Oklahoma and Kansas); and the Rocky Mountain Region (Colorado, Montana, Nevada, Wyoming and California). The international areas of operations include Argentina, China, Ecuador, Equatorial Guinea, the Mediterranean Sea (Israel) and the North Sea (the Netherlands and the United Kingdom). The Company also markets domestic crude oil and natural gas production through a wholly-owned subsidiary, NEMI.

The Company's accompanying consolidated financial statements, including the notes thereto, contain detailed information that should be referred to in conjunction with the following discussion.

EXECUTIVE OVERVIEW

Noble Energy's principal business strategy has been to create shareholder value by generating stable cash flow and production from domestic operations, while generating growth from international projects. In the U.S., the Company has a substantial onshore and offshore asset base located in established, prolific basins where the Company is aggressively pursuing exploration and exploitation opportunities. Offshore, exploration focuses on the deepwater and deep shelf areas of the Gulf of Mexico. Internationally, the Company has built a strong project portfolio and has applied innovative approaches to developing markets for stranded natural gas, including construction of a natural gas-fired power plant near Machala, Ecuador, and liquefied petroleum gas and methanol plants in Equatorial Guinea.

The Company had a successful year, both financially and operationally, in 2004. Financial highlights included the following:

- Record net income of $328.7 million, or $5.64 per share;
- Cash flow from operating activities of $708.2 million;
- A $48.7 million reduction in outstanding debt with a year-end debt-to-book capital ratio of 38 percent;
- Issuance of $200 million senior notes;
- Increased financial flexibility with an additional $400 million credit facility; and
- Completion of asset disposition program first announced in July 2003.

Operational highlights included the following:

- A 16 percent increase in daily equivalent production over 2003;
- Ticonderoga deepwater discovery in the Gulf of Mexico;
- New projects in the deepwater Gulf of Mexico;
- Commencement of natural gas sales in Israel;
- Phase 2A ramp-up in Equatorial Guinea; and
- Acquisition of interests in two PSC's with the Republic of Equatorial Guinea.

Domestic – Domestic operations benefited from higher realized prices for crude oil in 2004, and a four percent overall increase in production. During 2004, Noble Energy participated in 130 gross domestic exploration and development wells, of which 104 were successful.

Based on the results of successful infill pilot projects drilled during 2004, regulatory approval for 40-acre drilling density was granted for development of the Niobrara formation in northeast Colorado. Noble Energy plans to drill up to 235 development wells in the Niobrara Trend in 2005. The 2005 program is now underway with three drilling rigs currently operating in the area.

During 2004, the Company's domestic division continued to make progress on significant deepwater developments in the Gulf of Mexico that are expected to add substantial new production through 2006:

- Swordfish (Viosca Knoll 917, 961 and 962) - well completions have been finished, with production expected to commence from three wells in the second quarter of 2005 at an initial rate of approximately 10,000 Boepd, net to the Company. Noble Energy has a 60 percent working interest in Swordfish.

- Lorien (Green Canyon 199) - an appraisal well is currently underway, with production expected to commence in the first half of 2006 at an initial rate of approximately 12,000 Boepd, net to the Company. Noble Energy has a 60 percent working interest in Lorien.

- Ticonderoga (Green Canyon 768) - successful exploration results were announced in April 2004, with production expected to commence by mid-2006 at an initial rate of approximately 10,000 to 12,000 Boepd, net to the Company. Noble Energy has a 50 percent working interest in Ticonderoga.

Production from Main Pass 293/305/306 in the Gulf of Mexico remains shut in as a result of damage caused by Hurricane Ivan during September 2004. Estimated shut-in production totaled 3,500 Boepd during fourth quarter 2004 and 2,900 Boepd during third quarter 2004. The effect on total year 2004 production was 1,870 Boepd. The Company believes it has insurance coverage in an amount sufficient to make necessary repairs in order to re-establish production at Main Pass. Costs related to clean-up and redevelopment are insured to a limit that the Company believes will allow for restoration of production. The loss of production is not covered by business interruption insurance.

International – During 2002 and 2003, the Company completed major, capital-intensive projects in Ecuador, China, Israel and the Phase 2A expansion, the first phase of a two-phase project in Equatorial Guinea. With these important projects completed, international capital commitments declined. During 2003 and 2004, these projects contributed significantly to the Company's financial and operating results. The Phase 2B expansion in Equatorial Guinea is underway and is scheduled to be completed during 2005. The Phase 2B expansion is expected to increase both LPG and condensate production. The project includes increasing processing capacity, storage and offloading facilities at the existing LPG plant.

During 2004, international production volumes increased 12,098 Boepd, or 37 percent, compared to last year, primarily from increased production in Equatorial Guinea, due to the continued ramp-up of the Phase 2A expansion project, and the commencement of natural gas sales in Israel. International operations also benefited from higher realized commodity prices. During 2004, Noble Energy participated in 95 gross international exploration and development wells, of which 92 were successful.

CRITICAL ACCOUNTING POLICIES AND 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 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. When alternatives exist among various accounting methods, the choice of accounting method can have a significant impact on reported amounts. The following is a discussion of the Company's accounting policies, estimates and judgments which management believes are most significant in its application of generally accepted accounting principles used in the preparation of the consolidated financial statements.

Reserves – All of the reserve data in this Form 10-K are estimates. The Company's estimates of crude oil and natural gas reserves are prepared by the Company's engineers in accordance with guidelines established by the SEC. 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 crude oil and natural gas reserves. Uncertainties include the projection of future production rates and the expected timing of development expenditures. 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. Estimates of proved crude oil and natural gas reserves significantly affect the Company's depreciation, depletion and amortization ("DD&A") expense. For example, if estimates of proved reserves decline, the

Company's DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves could also trigger an impairment analysis and could result in an impairment charge.

SEC guidelines do not limit reserve bookings to only contracted volumes if it can be demonstrated that there is reasonable certainty that a market exists. The Company has booked reserves in excess of contracted volumes for Israel due to the reasonable certainty of the existence of markets in future periods. In Israel, the Company has a natural gas contract with IEC, which is expected to run through 2014, and a contract with the Israel Bazan Refinery through the year 2015. The Israeli natural gas market, as estimated by the Israeli Ministry of National Infrastructure, from 2005 to 2020, is significantly greater than Noble Energy's uncontracted net estimated proved reserves.

Oil and Gas Properties – The Company accounts for its crude oil and natural gas properties under the successful efforts method of accounting. The alternative method of accounting for crude oil and natural gas properties is the full cost method. Under the successful efforts 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. Application of the successful efforts method results in the expensing of certain costs including geological and geophysical costs, exploratory dry holes and delay rentals, during the periods the costs are incurred. Under the full cost method, these costs are capitalized as assets and charged to earnings in future periods as a component of DD&A expense. The Company believes the successful efforts method is the most appropriate method to use to account for its crude oil and natural gas production activities because during periods of active exploration, this method results in a more conservative measurement of net assets and net income. If the Company had used the full cost method, its financial position and results of operations would have been significantly different.

Exploratory Well Costs – In accordance with the successful efforts method of accounting, the costs associated with drilling an exploratory well (including costs in work-in-progress and suspended costs on go-forward projects) may be capitalized temporarily, or "suspended," pending a determination of whether commercial quantities of crude oil or natural gas have been discovered. Except as noted below, the Company does not capitalize the costs associated with drilling an exploratory well for more than one year following completion of drilling unless the exploratory well finds crude oil and natural gas reserves in an area requiring a major capital expenditure and (1) the well has found sufficient quantity of reserves to justify its completion as a producing well if the required capital expenditure is made and (2) drilling of the additional exploratory wells is under way or firmly planned for the near future. For certain capital-intensive deepwater Gulf of Mexico or international projects, it may take the Company more than one year to evaluate the future potential of the exploration well and make a determination of its economic viability. The Company's ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond the Company's control. In such cases, exploratory well costs remain suspended as long as the Company is actively pursuing such permits and approvals and believes they will be obtained. Management continuously monitors suspended exploratory well costs until a decision can be made that the well has found proved reserves or is noncommercial and is impaired. These costs may be charged to exploration expense in future periods if the Company decides not to pursue additional exploratory or development activities. At December 31, 2004, the balance of property, plant and equipment included $62.7 million of suspended exploratory well costs, of which $17.7 million had been capitalized for a period greater than one year. The wells relating to these suspended costs continue to be evaluated by various means including additional seismic work, drilling additional wells or evaluating the potential of the exploration wells. For more information, see "Note 5 - Capitalized Exploratory Well Costs" of this Form 10-K.

Impairment of Oil and Gas Properties – The Company assesses proved crude oil and natural gas properties for possible impairment when events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. The Company recognizes an impairment loss as a result of a triggering event and when the estimated undiscounted future cash flows from a property are less than the current net book value. Estimated future cash flows are based on management's expectations for the future and include estimates of crude oil and natural gas reserves and future commodity prices and operating costs. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate a property impairment. The Company recorded $9.9 million of impairments in 2004, primarily related to downward reserve revisions on two domestic properties. The Company recorded $31.9 million of impairments in 2003, primarily related to a reserve revision on a property in the Gulf of Mexico after recompletion and remediation activities produced less-than-expected results.

The Company also performs periodic assessments of individually significant unproved crude oil and natural gas properties for impairment. Management's assessment of the results of exploration activities, estimated future commodity prices and operating costs, availability of funds for future activities and the current and projected political climate in areas in which the Company operates impact the amounts and timing of impairment provisions.

Asset Retirement Obligation – The Company's asset retirement obligations ("ARO") consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with its oil and gas properties. Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations," requires that the discounted fair value of a liability for an ARO be recognized in the period in which it is incurred with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The recognition of an ARO requires that management make numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to initial measurement of the ARO, the Company must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A. At December 31, 2004, the Company's balance sheet included a liability for ARO of $255.0 million, including $130.0 million for damage caused by Hurricane Ivan.

Derivative Instruments and Hedging Activities – The Company uses various derivative instruments to hedge its exposure to price risk from changing commodity prices. Except for NEMI's use of derivative instruments in connection with its purchases and sales of third-party production to lock in profits or limit exposure to natural gas price risk, the Company does not enter into derivative or other financial instruments for trading purposes. Management exercises significant judgment in determining types of instruments to be used, production volumes to be hedged, prices at which to hedge and the counterparties and the hedging counterparties' creditworthiness. The Company accounts for its derivative instruments under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. For derivative instruments that qualify as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in accumulated other comprehensive income ("AOCI") until the forecasted transaction is recognized in earnings. Therefore, prior to settlement of the derivative instruments, changes in the fair market value of those derivative instruments can cause significant increases or decreases in AOCI. For derivative instruments that do not qualify as cash flow hedges, changes in fair value must be reported in the current period, rather than in the period in which the forecasted transaction occurs. This may result in significant increases or decreases in current period net income. All hedge ineffectiveness is recognized in the current period in net income.

Income Taxes – The Company is subject to income and other taxes in numerous taxing jurisdictions worldwide. For financial reporting purposes, the Company provides taxes at rates applicable for the appropriate tax jurisdictions. Estimates of amounts of income tax to be recorded involve interpretation of complex tax laws, including the recently enacted American Jobs Creation Act of 2004, and assessment of the effects of foreign taxes on domestic taxes.

The Company's balance sheet includes deferred tax assets related to deductible temporary differences and operating loss carryforwards. Ultimately, realization of a deferred tax benefit depends on the existence of sufficient taxable income within the future periods to absorb future deductible temporary differences or loss carryforwards. In assessing the realizability of deferred tax assets, management must consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. Management considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. Such evidence includes the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment, and judgment is required in considering the relative weight of negative and positive evidence. As a result of management's assessment during 2004, the Company decreased the valuation allowances associated with certain foreign loss carryforwards from $14.5 million at December 31, 2003 to zero December 31, 2004. The Company will continue to monitor facts and circumstances in its reassessment of the likelihood that operating loss carryforwards and other deferred tax assets will be utilized prior to their expiration. As a result, the Company may determine that a deferred tax asset valuation allowance should be established. Any increases or decreases in a deferred tax asset valuation allowance would impact net income through offsetting changes in income tax expense.

For a discussion of the effect on the Company of the American Jobs Creation Act of 2004, see "Impact of Recently Issued Accounting Pronouncements" of this Form 10-K.

Pension Plan – The Company sponsors a defined benefit pension plan and other postretirement benefit plans. The actuarial determination of the projected benefit obligation and related benefit expense requires that certain assumptions be made regarding such variables as expected return on plan assets, discount rates, rate of compensation increase, estimated employee turnover rates and retirement dates, lump-sum election rates, mortality rate, retiree utilization rates for health care services and health care cost trend rates. The selection of assumptions requires considerable judgment concerning future events and has a significant impact on the amount of the obligation recorded on the Company's balance sheets and on the amount of expense included on the Company's statements of operations, as well as on funding.

Noble Energy bases its determination of the asset return component of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2004, the Company had cumulative asset losses of approximately $2.2 million, which remain to be recognized in the calculation of the market-related value of assets.

The Company utilizes the services of an outside actuarial firm to assist in the calculations of the projected benefit obligation and related costs. The Company and its actuaries use historical data and forecasts to determine assumptions. In selecting the assumption for expected long-term rate of return on assets, the Company considers the average rate of earnings expected on the funds to be invested to provide for plan benefits. This includes considering the plan's asset allocation, historical returns on these types of assets, the current economic environment and the expected returns likely to be earned over the life of the plan. It is assumed that the long-term asset mix will be consistent with the target asset allocation of 70 percent equity and 30 percent fixed income, with a range of plus or minus 10 percent acceptable degree of variation in the plan's asset allocation. The discount rate is determined by analyzing the interest rates implicit in current annuity contract prices and available yields on high quality fixed income securities. By definition, discount rates reflect rates at which pension benefits could be effectively settled. A one percent decrease in the expected return on plan assets assumption would have increased 2004 benefit expense by $.8 million.

The expected return assumption for 2005 is 8.5 percent and the assumed discount rate for 2005 is 6.0 percent. The expected return assumption was the same as 2004 and the assumed discount rate was 6.25 percent for 2004.

LIQUIDITY AND CAPITAL RESOURCES

Overview

The Company's primary cash needs are to fund capital expenditures related to the acquisition, exploration and development of crude oil and natural gas properties, to repay outstanding borrowings or to pay other contractual commitments, for interest payments on debt, to pay cash dividends on common stock and to fund contributions to the Company's pension and postretirement benefit plans. The Company's traditional sources of liquidity are its cash on hand, cash flows from operations and available borrowing capacity under its credit facilities. Funds may also be generated from occasional sales of non-strategic crude oil and natural gas properties. The Company made significant progress during 2003 and 2004 in improving liquidity and financial flexibility. Reduction in international capital commitments due to completion of major capital-intensive projects has increased flexibility and liquidity in 2004. With these projects completed or nearing completion, international capital commitments have declined while, at the same time, they have begun to contribute to the Company's financial and operating results. A new $400 million credit facility will also provide increased liquidity in 2005.

The Company achieved a reduction in its ratio of debt-to-book capital (defined as the Company's total debt divided by the sum of total debt plus equity) to 38 percent at December 31, 2004, compared to 46 percent at December 31, 2003. The Company reduced outstanding debt by $48.7 million during 2004.

The Company's current ratio (current assets divided by current liabilities) was 1.10:1 at December 31, 2004, compared with .73:1 at December 31, 2003. The improvement in the current ratio in 2004, as compared to 2003, resulted primarily from a $117.4 million increase in the year-end balance of cash and cash equivalents, and a $153.7 million decrease in current installments of long-term debt. In addition, the year-end balance of accounts receivable-trade increased by $103.5 million due primarily to increases of $59.2 million for gas sales at NEMI, $17.6 million for joint operations receivables, $13.0 million for crude oil and natural gas accruals in the U.S. and U.K. and $8.3 million for electricity sales in Ecuador.

Cash Flows

Operating Activities – The Company reported a $105.4 million year-over-year increase in cash flows from operating activities. Net cash provided by operating activities totaled $708.2 million for the year ended December 31, 2004, compared to $602.8 million in 2003 and $507.0 million in 2002. The increases for 2004 and 2003 were driven by overall production increases, higher realized commodity prices and higher distributions from the Company's unconsolidated methanol subsidiary.

Investing Activities – Net cash used in investing activities totaled $588.1 million, $444.8 million and $577.5 million for the years ending December 31, 2004, 2003 and 2002, respectively. The Company's investing activities relate primarily to expenditures made for the exploration and development of oil and gas properties. Expenditures were offset by the receipt of $62.5 million, $81.1 million and $20.4 million from sales of assets during 2004, 2003 and 2002, respectively.

Financing Activities – Net cash provided by/(used in) financing activities totaled ($2.7) million, ($111.0) million and $12.8 million for the years ending December 31, 2004, 2003 and 2002, respectively. Financing activities consist primarily of proceeds from and repayments of bank or other long-term debt, repayment of notes payable, the payment of cash dividends and proceeds from the exercise of stock options. During 2004, the Company had a net $48.7 million reduction in outstanding debt. In addition, the Company received $62.6 million from the exercise of stock options.

Capital Expenditures

Selected capital expenditures incurred in oil and gas activities, acquisitions and downstream projects consisted of the following:

	Year Ended December 31,		
(in thousands)	**2004**	**2003**	**2002**
Oil and gas mineral interests, equipment and facilities	$ 501,119	$ 481,236	$ 505,464
Proved property acquisition costs	85,785	1,294	7,988
Unproved property acquisition costs	44,681	10,234	30,515
Downstream projects	970	45,134	57,646

Total capital expenditures during 2004 increased $133.5 million, or 25 percent, as compared with 2003. The increase included costs related to the acquisition of deepwater Gulf of Mexico interests and costs expended in further development of the Amistad gas field in Ecuador. Capital expenditures during 2003 declined $68.4 million or 11 percent from 2002. This decrease in spending was the result of declining capital commitments due to the completion, or near completion, of major capital-intensive projects in international locations.

Capital expenditures, as included in investing activities in the consolidated statements of cash flows, and the capital expenditures budget were as follows:

	Year Ended December 31,		
(in thousands)	**2004**	**2003**	**2002**
Capital expenditures from investing activities	$ 660,851	$ 527,386	$ 595,739
Capital expenditures budget	$ 750,000	$ 510,000	$ 519,000

Capital expenditures during 2004 were lower than budgeted amounts due to timing of capital outlays, which were delayed until 2005, for certain projects in the Gulf of Mexico, the United Kingdom, Israel and Phase 2B in Equatorial Guinea. Capital spending in excess of budget for 2003 was primarily due to the acceleration of the initial costs to begin the Phase 2B expansion in Equatorial Guinea. During 2002, additional capital expenditures were for the completion of the natural gas-to-power project in Ecuador and the continued development of the Israel project.

2005 Budget – The Company has budgeted capital expenditures of $735.0 million for 2005. Approximately 30 percent of the 2005 capital budget has been allocated for exploration opportunities, and 70 percent has been dedicated to production, development and other projects. Domestic spending is budgeted at $485.0 million (66 percent of the worldwide 2005 capital budget), international expenditures are budgeted at $228.0 million (31 percent) and corporate expenditures are budgeted at $22.0 million (three percent). The 2005 budget does not include the impact of Noble Energy's possible asset purchases or the previously announced proposed merger with Patina.

The Company expects that its 2005 capital expenditure budget will be funded primarily from cash flows from operations. The Company will evaluate its level of capital spending throughout the year based upon drilling results, commodity prices, cash flows from operations and property acquisitions.

Discontinued Operations and Asset Sales

During 2004, the Company completed an asset disposition program, including five domestic property packages that had first been announced during July 2003. The sales price for the five property packages totaled approximately $130 million before closing adjustments. The Company's consolidated financial statements have been reclassified for all periods presented to reflect the operations and assets of the properties being sold as discontinued operations. Income from discontinued operations was $14.9 million for the year ended December 31, 2004. The loss from discontinued operations of $6.1 million for the year ended December 31, 2003 included a $59.2 million ($38.5 million, net of tax) non-cash write-down to market value for certain of the five property packages.

Proceeds from asset sales totaled $62.5 million, $81.1 million and $20.4 million in 2004, 2003 and 2002, respectively. The Company believes the disposition of non-strategic properties allows it to concentrate efforts on strategic properties and reduce leverage.

Financing Activities

Debt – The Company's debt totaled $880.3 million at December 31, 2004, all of which was long-term with maturities ranging from 2009 to 2097.

The Company's principal sources of liquidity are its credit facilities, including the following:

- A $400 million credit agreement due November 30, 2006 with certain commercial lending institutions which bears facility fees of 15 to 30 basis points per annum and interest rates based upon a Eurodollar rate plus a range of 60 to 145 basis points per annum, depending upon the percentage of utilization and the Company's credit rating. At December 31, 2004, there were no borrowings outstanding under this credit agreement.
- A $400 million five-year credit facility due October 2009 with certain commercial lending institutions which bears facility fees of 10 to 25 basis points per annum and interest rates based upon a Eurodollar rate plus a range of 30 to 112.5 basis points per annum, depending upon the percentage of utilization and the Company's credit rating. At December 31, 2004, there was $85.0 million borrowed against this credit agreement leaving $315.0 million of unused borrowing capacity.

Financial covenants on each of the $400 million credit facilities include the following: (a) the ratio of Earnings Before Interest, Taxes, Depreciation and Exploration Expense ("EBITDAX") to 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 Company may not incur any guaranteed liabilities in respect of any funded indebtedness of any unrestricted subsidiary in excess of $700 million in the aggregate for all such guaranteed liabilities.

The Company's credit agreements are supplemented by short-term borrowings under various uncommitted credit lines used for working capital purposes. The uncommitted credit lines may be offered by certain banks from time to time at rates negotiated at the time of borrowing.

Debt Issuances – During April 2004, the Company closed an offering of $200 million senior unsecured notes receiving net proceeds of approximately $197.7 million, after deducting underwriting discounts and expenses. The notes mature April 15, 2014 and pay interest semi-annually at 5.25 percent. The net proceeds from the offering were used to repay amounts outstanding under the credit agreements and for general corporate purposes.

During first quarter 2004, a subsidiary of the Company, Noble Energy Mediterranean, Ltd., entered into term loan agreements with several commercial lending institutions for a total of $150 million. The interest rates on the borrowings are based upon a Eurodollar rate plus an effective range of 60 to 130 basis points depending upon the Company's credit rating. The Term Loans expire in January 2009. Proceeds were used to reduce amounts outstanding under the credit agreements.

Debt Repayments – During 2004, the Company repaid the following:

- $125 million AMCCO Series A-2 Notes due December 2004. In connection with the repayment, the Company recognized a loss of $2.9 million ($1.9 million after tax), which is included in interest expense on the Company's consolidated statements of operations. The repayment of the Notes was funded with borrowings under the Company's credit facility.
- $7.9 million on an acquisition note and $20.7 million of Israel debt.

The Company made cash interest payments of $46.6 million, $46.0 million and $47.6 million during 2004, 2003 and 2002, respectively.

Dividends – The Company paid quarterly cash dividends of four cents per share from 1989 through the third quarter 2003. For fourth quarter 2003 and for each quarter of 2004, the Company's Board of Directors declared a quarterly cash dividend of five cents per common share. The amount of future dividends will be determined on a quarterly basis at the discretion of the Company's Board of Directors and will depend on earnings, financial condition, capital requirements and other factors.

Exercise of Stock Options – The Company received $62.6 million, $24.7 million and $7.7 million from the exercise of stock options during 2004, 2003 and 2002, respectively. Proceeds received by the Company from the exercise of stock options fluctuate primarily based on the price at which the Company's common stock trades on the NYSE in relation to the exercise price of the options issued. During 2004, the Company's stock reached higher sales prices than during 2003 or 2002, resulting in the exercise of more options and more proceeds to the Company.

Other

Contributions to Pension and Other Postretirement Benefit Plans – The Company made contributions of $4.8 million to its pension and other postretirement benefit plans during 2004, $14.6 million during 2003 and $10.9 million during 2002. The Company expects to make cash contributions of $12.3 million to its pension plan during 2005. During 2004, the actual return on plan assets was a positive $7.9 million, while the returns in 2003 and 2002 were a positive $7.6 million and a negative $3.5 million, respectively. The value of the plan assets has tended to follow market performance. The expected return assumption for 2005 is 8.5 percent and the assumed discount rate for 2005 is 6.0 percent. The expected return assumption was the same as 2004. The assumed discount rate was 6.25 percent for 2004. The decrease in discount rate from 6.25 percent to 6.0 percent results in an increase in projected benefit obligation of $4.0 million. A one percent decrease in the expected return on plan assets would have resulted in an increase in benefit expense of $.8 million in 2004.

Federal Income Taxes – The Company made cash payments for federal income taxes of $112.3 million during 2004 and $55.5 million during 2003. During 2002, the Company received a federal tax refund of $40.4 million. The refund related to large estimated tax payments made during the first half of 2001 followed by a period of declining commodity prices, which resulted in lower taxable income by the end of 2001.

Contingencies – During 2004, no significant payments were made to settle any of the Company's legal proceedings. During 2003, the Company paid $1.9 million in settlement of two legal proceedings conducted in the ordinary course of business. During 2002, the Company paid $7.0 million in settlement of a legal proceeding conducted in the ordinary course of business. The Company regularly analyzes current information and accrues for probable liabilities on the disposition of certain matters, as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

Contractual Obligations

The following table summarizes the Company's contractual obligations as of December 31, 2004.

(in thousands)	**Payments Due by Period**				
Contractual Obligations	**Total**	**Less Than 1 Year**	**1 to 3 Years**	**4 to 5 Years**	**After 5 Years**
Outstanding debt	$ 885,000	$	$	$ 235,000	$ 650,000
Asset retirement obligations (1)	254,983	79,568	91,115	14,330	69,970
Derivative instruments	59,982	50,304	9,662	16	
Building lease	11,647	1,588	3,176	3,176	3,707
Total contractual obligations	$ 1,211,612	$ 131,460	$ 103,953	$ 252,522	$ 723,677

(1) Asset retirement obligations are discounted.

In addition, in the ordinary course of business, the Company maintains letters of credit in support of certain performance obligations of its subsidiaries. Outstanding letters of credit totaled approximately $4.1 million at December 31, 2004. For more information, see "Item 8. Financial Statements and Supplementary Data—Note 7 - Debt" of this Form 10-K.

RESULTS OF OPERATIONS

Net Income and Revenues

The Company's net income for 2004 was $328.7 million, an increase of over 300 percent compared to 2003 net income. Factors contributing to the increase included:

- A 57 percent, or $209.0 million, increase in crude oil sales due to a 26 percent increase in daily production and a 25 percent increase in average realized crude oil prices;
- A 27 percent, or $126.0 million, increase in natural gas sales due to a nine percent increase in daily production and a 15 percent increase in average realized natural gas prices;
- A 21 percent, or $31.8 million, decrease in exploration expense; and
- A 70 percent, or $28.5 million, increase in income from unconsolidated subsidiaries.

Natural Gas Information

Natural gas revenues increased 27 percent in 2004 compared to 2003 due to a 15 percent increase in average realized natural gas prices and a nine percent increase in daily natural gas production. Natural gas revenues increased 35 percent in 2003, compared to 2002, due to a 43 percent increase in natural gas prices, offset by a one percent decrease in daily natural gas production.

	Year Ended December 31,		
(in thousands)	**2004**	**2003**	**2002**
Natural gas sales	$ 600,806	$ 474,762	$ 351,591

The table below depicts average daily natural gas production and prices from continuing operations by area for the last three years.

	2004		2003		2002	
	Mcfpd	**Price per Mcf**	**Mcfpd**	**Price per Mcf**	**Mcfpd**	**Price per Mcf**
United States (1)	240,647	$ 6.00	260,560	$ 4.75	280,836	$ 3.24
Equatorial Guinea (2)	45,755	$ .25	39,906	$ .25	34,382	$ .25
North Sea	11,286	$ 4.73	13,861	$ 3.86	16,991	$ 3.14
Israel	48,015	$ 2.78		$		$
Other International (3)	21,262	$ .75	22,284	$ .41	8,799	$ .38
Total	366,965	$ 4.74	336,611	$ 4.13	341,008	$ 2.89

(1) Reflects reductions of $.08 per Mcf in 2004 and $.44 per Mcf in 2003, and an increase of $.05 per Mcf in 2002 from hedging in the United States.

(2) Natural gas in Equatorial Guinea is under a contract for $.25 per MMBTU through 2026.

(3) Ecuador natural gas volumes are included in Other International production, but are not included in natural gas sales revenues and average price. The natural gas-to-power project in Ecuador is 100 percent owned by Noble Energy and intercompany natural gas sales are eliminated for accounting purposes.

Variances in natural gas production were attributable to the following:

- Natural decline rates for properties in the Gulf of Mexico and the onshore Gulf Coast region;
- Natural decline rates for properties in the United Kingdom section of the North Sea;
- Higher throughput and reduced downtime for the methanol plant in Equatorial Guinea;
- Commencement of natural gas sales in Israel in February 2004; and
- Ramp-up of natural gas production in Ecuador, included in Other International, which began in September 2002.

Crude Oil Information

Crude oil revenues increased 57 percent during 2004, compared to 2003, due to a 25 percent increase in crude oil prices and a 26 percent increase in daily crude oil production. Crude oil revenues increased 42 percent during 2003, compared to 2002, due to a 14 percent increase in crude oil prices and a 24 percent increase in daily crude oil production.

	Year Ended December 31,		
(in thousands)	**2004**	**2003**	**2002**
Crude oil sales	$ 573,393	$ 364,382	$ 257,435

The table below depicts average daily crude oil production and prices from continuing operations by area for the last three years.

	2004		2003		2002	
	Bopd	**Price per Bbl**	**Bopd**	**Price per Bbl**	**Bopd**	**Price per Bbl**
United States (1)	21,725	$ 31.90	16,084	$ 26.21	13,187	$ 23.29
Equatorial Guinea	10,084	$ 37.62	6,377	$ 27.93	5,259	$ 23.88
North Sea	6,718	$ 38.90	7,412	$ 29.95	7,847	$ 25.15
Other International	6,848	$ 34.00	6,141	$ 28.75	2,821	$ 26.58
Total	45,375	$ 34.53	36,014	$ 27.72	29,114	$ 24.22

(1) Reflects a reduction of $3.05 per Bbl in 2004, $1.01 per Bbl in 2003 and $.02 per Bbl in 2002 from hedging in the United States.

Variances in crude oil production were attributable to the following:

- New crude oil production in the Gulf of Mexico reflecting the success of the Company’s deepwater and shelf projects, including Green Canyon 282 (“Boris”), South Timbalier 315/316 (“Roaring Fork”) and West Cameron 518;
- Natural production declines in the North Sea;
- Ramp-up of the Phase 2A expansion project in the Alba field in Equatorial Guinea; and
- Increased production in China, included in Other International, due to the startup of the CDX field, located in South Bohai Bay off the coast of China, in January 2003.

Electricity Sales - Ecuador Integrated Power Project

The Company, through its subsidiaries, EDC Ecuador Ltd. and MachalaPower Cia. Ltda., has a 100 percent ownership interest in an integrated natural gas-to-power project. The project includes the Amistad natural gas field, offshore Ecuador, which supplies fuel to the Machala Power Plant. The Machala Power Plant commenced commercial electricity generation in September 2002.

Operations data is as follows:

	Year Ended December 31,		
	2004	2003	2002
Operating income (in thousands)	$ 10,839	$ 7,176	$ 2,311
Power production (total MW)	720,300	751,689	269,229
Average power price ($/Kwh)	$ 0.081	$ 0.077	$ 0.068

The volume of natural gas and MW produced in Ecuador are related to thermal electricity demand in that country and typically decline at the onset of the rainy season. When Ecuador has sufficient rainfall to allow hydroelectric power producers to provide base load power, Noble Energy provides electricity to meet peak demand. As seasonal rains subside, the Company experiences increasing demand for thermal electricity. During 2004, the Machala Power Plant experienced lower power production due to normal seasonal weather variation and extended summer maintenance. Maintenance on one turbine took longer than expected after inspections uncovered damage that required repair work in the U.S. Full repairs have been completed.

Income from Unconsolidated Subsidiaries

Noble Energy's income from unconsolidated subsidiaries consists of income from methanol operations. The Company's share of methanol operations was as follows:

	Year Ended December 31,		
	2004	2003	2002
Income from unconsolidated subsidiaries (in thousands)	$ 69,100	$ 40,626	$ 9,532
Methanol sales volumes (gallons in thousands)	146,821	122,015	105,126
Average realized price per gallon	$ 0.69	$ 0.65	$ 0.43

Methanol production increased during 2004 as a result of higher throughput and reduced downtime. Dividends from unconsolidated subsidiaries contributed $57.8 million, $46.1 million and $17.7 million to the Company's net cash provided by operating activities during 2004, 2003 and 2002, respectively.

Derivative Instruments and Hedging Activities

The Company uses various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations. Such instruments include fixed price contracts, variable to fixed price swaps, costless collars and other contractual arrangements. Although these derivative instruments 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. During 2004, 2003 and 2002, the Company recognized a reduction of revenues of $61.3 million and $67.5 million, and an increase in revenues of $5.9 million, respectively, related to its cash flow hedges in oil and gas sales and royalties.

Costs and Expenses

Production Costs – Production costs, from continuing operations, consisting of lease operating expense, workover expense, production and ad valorem taxes and transportation costs increased $44.8 million in 2004 compared to 2003. The increase was due to new operations in Israel, increased production from the ramp-up of Phase 2A in Equatorial Guinea and new production in the Gulf of Mexico. Other factors affecting operations expense included increased service costs and workovers.

Production costs increased $38.7 million in 2003 compared to 2002. The increase was due to several factors, including new operations in China, increased production and the startup of Phase 2A in Equatorial Guinea, new production in the Gulf of Mexico and higher production taxes.

The table below includes the crude oil and natural gas production costs from continuing operations by area for the last three years.

(in thousands)	Consolidated	United States	Equatorial Guinea	Israel(2)	North Sea	Other Int'l
2004						
Lease operating (1)	$ 142,060	$ 85,013	$ 23,936	$ 7,366	$ 11,104	$ 14,641
Workover expense	16,635	16,635				
Total operations expense	158,695	101,648	23,936	7,366	11,104	14,641
Production and ad valorem taxes	28,022	21,806				6,216
Transportation costs	18,553				10,480	8,073
Total production costs	$ 205,270	$ 123,454	$ 23,936	$ 7,366	$ 21,584	$ 28,930
2003						
Lease operating (1)	$ 116,811	$ 72,107	$ 16,319	$	$ 10,662	$ 17,723
Workover expense	6,303	6,303				
Total operations expense	123,114	78,410	16,319		10,662	17,723
Production and ad valorem taxes	22,722	17,850				4,872
Transportation costs	14,679				9,024	5,655
Total production costs	$ 160,515	$ 96,260	$ 16,319	$	$ 19,686	$ 28,250
2002						
Lease operating (1)	$ 79,326	$ 58,375	$ 9,848	$	$ 10,817	$ 286
Workover expense	8,875	8,880			(5)	
Total operations expense	88,201	67,255	9,848		10,812	286
Production and ad valorem taxes	17,157	15,126				2,031
Transportation costs	16,441				9,618	6,823
Total production costs	$ 121,799	$ 82,381	$ 9,848	$	$ 20,430	$ 9,140

(1) Lease operating expense includes labor, fuel, repairs, replacements, saltwater disposal and other related lifting costs.

(2) Sales began in 2004.

Selected expenses on a per BOE basis were as follows:

	Year Ended December 31, 2004	2003	2002
Lease operating	$ 3.64	$ 3.47	$ 2.53
Workover expense	0.43	0.19	0.28
Total operations expense	$ 4.07	$ 3.66	$ 2.81
Production and ad valorem taxes	0.72	0.68	0.55
Transportation costs	0.48	0.44	0.52
Total production costs	$ 5.27	$ 4.78	$ 3.88

Depreciation, Depletion and Amortization Expense – In 2004, DD&A expense from continuing operations remained flat. Although production increased during 2004, unit rates decreased primarily due to increased low-cost volumes in Equatorial Guinea and Israel. In 2004, DD&A expense includes $15.4 million of abandoned assets expense and $16.3 million of DD&A related to asset retirement obligations.

In 2003, DD&A expense from continuing operations increased $72.5 million compared to 2002. The increase was primarily due to higher domestic DD&A rates and increased production volumes. Also, included in DD&A for 2003 is $20.6 million of abandoned assets expense and $20.2 million of DD&A related to asset retirement obligations, which increased DD&A by $1.26 per BOE as compared with 2002. The table below includes the DD&A from continuing operations for the years ended December 31:

(in thousands)	2004	2003	2002
United States	$ 240,058	$ 254,041	$ 192,708
Equatorial Guinea	14,677	6,115	5,849
North Sea	18,244	28,219	28,279
Israel	9,058	40	31
Other International, Corporate and Other	26,818	20,928	10,014
Total DD&A expense	$ 308,855	$ 309,343	$ 236,881
Unit rate of DD&A per BOE	$ 7.92	$ 9.20	$ 7.55

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

(in thousands)	Consolidated	United States	Equatorial Guinea	Israel	North Sea	Other Int'l
2004						
Dry hole expense	$ 46,192	$ 34,236	$ 4,676	$ 293	$ 6,789	$ 198
Unproved lease amortization	19,280	18,705		525	50	
Seismic	23,360	20,288	2,115		550	407
Staff expense	22,990	13,926	260	305	3,374	5,125
Other	5,179	4,737	163		402	(123)
Total exploration expense	$ 117,001	$ 91,892	$ 7,214	$ 1,123	$ 11,165	$ 5,607
2003						
Dry hole expense	$ 63,637	$ 32,408	$	$ 6,711	$ 4,023	$ 20,495
Unproved lease amortization	33,381	25,296		900	1,264	5,921
Seismic	17,674	15,903	51		1,662	58
Staff expense	30,182	17,483	83	214	3,105	9,297
Other	3,944	3,601			449	(106)
Total exploration expense	$ 148,818	$ 94,691	$ 134	$ 7,825	$ 10,503	$ 35,665
2002						
Dry hole expense	$ 81,396	$ 64,449	$	$	$ 544	$ 16,403
Unproved lease amortization	21,254	19,426		900	178	750
Seismic	20,492	14,282	1,341	1,671	827	2,371
Staff expense	24,928	20,081		54	2,833	1,960
Other	2,631	2,457			828	(654)
Total exploration expense	$ 150,701	$ 120,695	$ 1,341	$ 2,625	$ 5,210	$ 20,830

Exploration expense declined $31.8 million, or 21 percent, in 2004 compared with 2003. Exploration expense for 2003 included a pre-tax charge of $20.2 million ($5.9 million after tax) to write off the Company's investment in Vietnam. Lower dry hole expense also contributed to lower overall exploration expense for 2004.

Impairment of Operating Assets

During 2004, the Company recorded $9.9 million of impairments, primarily related to downward reserve revisions on two domestic properties. In 2003, the Company recorded $31.9 million of impairments, primarily related to a reserve revision on the East Cameron 338 field in the Gulf of Mexico after recompletion and remediation activities produced less-than-expected results. An analysis of the performance response of the field resulted in a reduction in proved reserves of 2.2 MMBoe. The Company recorded no operating asset impairments during 2002. 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

Selling, general and administrative ("SG&A") expenses increased $6.6 million in 2004 compared to 2003 and increased $4.8 million in 2003 compared to 2002. The increase in SG&A expenses for 2004 primarily reflects fees associated with the implementation of Sarbanes-Oxley and increased salaries and bonuses. The increase in SG&A expenses for 2003 is due to increased corporate governance costs, professional fees and other costs related to Sarbanes-Oxley compliance and increased salary expense. On a BOE basis, SG&A expenses were $1.52, $1.56 and $1.52 for the years ended December 31, 2004, 2003 and 2002, respectively.

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, net of cost of goods sold, as GMP proceeds and NEMI's expenses as GMP. All intercompany sales and expenses have been eliminated in the Company's consolidated financial statements.

The GMP proceeds less expenses for NEMI are reflected in the table below.

(in thousands, except margins) (amounts include inter-company eliminations)	2004 Crude Oil	2004 Natural Gas	2003 Crude Oil	2003 Natural Gas	2002 Crude Oil	2002 Natural Gas
Proceeds	$ 20,610	$ 28,640	$ 31,867	$ 36,291	$ 26,824	$ 37,693
Expenses						
Transportation	12,086	20,269	21,456	28,844	20,323	29,000
General and administrative	43	5,301	182	8,632	802	3,857
Total expenses	$ 12,129	$ 25,570	$ 21,638	$ 37,476	$ 21,125	$ 32,857
Gross margin	$ 8,481	$ 3,070	$ 10,229	$ (1,185)	$ 5,699	$ 4,836
Traded volumes - Bbls/MMBTU	10,978	231,221	8,324	239,311	6,787	276,626
Margin per Bbl/MMBTU	$ .77	$ .01	$ 1.23	$ (.01)	$ .84	$ .02

NEMI employs various derivative instruments in connection with its purchases and sales of third-party production to lock in profits or limit exposure to natural 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 records gains and losses on derivative instruments using mark-to-market accounting. NEMI recorded a gain of less than $.1 million, a loss of $.2 million and a gain of $.9 million in GMP proceeds during 2004, 2003 and 2002, respectively, related to derivative instruments.

Interest Expense and Capitalized Interest

Interest expense remained relatively constant at $61.6 million, $61.1 million and $64.0 million during 2004, 2003 and 2002, respectively. Capitalized interest totaled $13.4 million, $14.1 million and $16.3 million during 2004, 2003 and 2002, respectively. Interest is capitalized on the Company's development projects. The majority of the capitalized interest relates to long lead-time projects in the deepwater and internationally, primarily Phase 2A and 2B in Equatorial Guinea.

Interest expense in 2004 includes $.5 million related to the reclassification of the deferred hedging loss from the settlement of an interest rate lock. The Company entered into the interest rate lock in late 2003 to protect against a rise in interest rates prior to the issuance of its $200 million senior unsecured notes in April 2004. At the time of the debt offering, the fair market value of the interest rate lock was a liability of $7.6 million ($4.9 million, net of tax). This amount is included in accumulated other comprehensive income/(loss) and is being amortized into earnings as an adjustment to interest expense over the term of the unsecured notes.

Interest rates decreased during 2002 and 2003 while Company borrowings increased, peaking early in 2003. Throughout the remainder of 2003, the Company steadily paid down its debt resulting in a year-over-year decrease of $2.9 million in interest expense at December 31, 2003 compared to the same period in 2002.

Pension Expense

The Company recognized net periodic benefit cost related to its pension and other postretirement benefit plans of $9.1 million, $7.9 million and $8.5 million during 2004, 2003 and 2002, respectively. This expense included an expected return on pension plan assets of $6.7 million, $5.9 million and $5.5 million during 2004, 2003 and 2002, respectively.

Allowance for Doubtful Accounts

The Company is exposed to credit risk and takes reasonable steps to protect itself from nonperformance by its debtors, but is not able to predict sudden changes in its debtors' creditworthiness. The Company periodically assesses its provision for bad debt allowance. The Company had allowances for doubtful accounts as of December 31, 2004 and 2003 of $13.1 million and $6.3 million, respectively. During 2004, the allowance was increased by $5.4 million to reflect additional collection allowances resulting from higher power prices in Ecuador and $1.4 million due to various allowances related to the Company's domestic business.

Other Expense/(Income)

Other expense/(income) for 2004 includes a gain of $4.4 million ($2.9 million, net of tax) from a transaction in which the Company exchanged its interests in the Tweedsmuir development project and the producing Buchan and Hannay fields located in the North Sea for an interest in the currently producing MacCulloch field, also located in the North Sea. The Company expects to receive a total of $8.2 million in cash as part of the exchange.

Income Taxes

Income tax expense associated with continuing operations increased to $202.2 million in 2004 from $51.7 million in 2003 due primarily to the increase in income. This increase in income tax expense was offset by the elimination of the Company's deferred tax asset valuation allowance related to China foreign loss carryforwards. The deferred tax asset valuation allowance decreased from $14.5 million at December 31, 2003 to zero at December 31, 2004. Due to the positive results of development activities in China and projections of future taxable income, management now believes it is more likely than not that the deferred tax asset related to the China foreign loss carryforward will be realized. The effective income tax rate increased to 39.2 percent in 2004 from 36.5 percent in 2003. This increase is primarily due to the tax benefit of the Vietnam write-off in 2003, partially offset by the benefit of the release of the China valuation allowance in 2004 and the greater weighting toward domestic income in 2004.

Income tax expense associated with continuing operations increased to $51.7 million in 2003 from $19.8 million in 2002 primarily from the increase in income. However, the effective income tax rate decreased to 36.5 percent in 2003 from 70.9 percent in 2002. During 2003, the Company's income from international operations increased over 2002, but represented a smaller proportion of the Company's total income. Some of the countries in which the international operations were conducted have a higher statutory income tax rate than the United States. Also impacting the effective rate in 2003 was the realization of approximately $15.6 million of tax benefits for certain prior year costs incurred in Israel and Vietnam.

Discontinued Operations

Summarized results of discontinued operations are as follows:

(dollars in thousands)	Year ended December 31, 2004	2003	2002
Revenues:			
Oil and gas sales and royalties	$ 12,575	$ 106,339	$ 91,576
Costs and Expenses:			
Write down to market value and realized (gain)/loss	(14,996)	59,171	
Oil and gas operations	4,709	27,731	28,468
Depreciation, depletion and amortization		28,762	48,405
Total costs and expenses	(10,287)	115,664	76,873
Income (Loss) Before Income Taxes	22,862	(9,325)	14,703
Income Tax Provision (Benefit)	8,002	(3,264)	5,146
Income (Loss) From Discontinued Operations	$ 14,860	$ (6,061)	$ 9,557
Key Statistics:			
Daily Production			
Liquids (Bbls)	225	4,106	4,923
Natural Gas (Mcf)	4,429	32,823	46,615
Average Realized Price			
Liquids ($/Bbl)	$ 33.96	$ 27.71	$ 22.57
Natural Gas ($/Mcf)	$ 6.03	$ 5.41	$ 3.00

The long-term debt of the Company is recorded at the consolidated level and is not reflected by each component. Thus, the Company has not allocated interest expense to the discontinued operations.

Cumulative Effect of Change in Accounting Principle, Net of Tax

The Company adopted SFAS No. 143 on January 1, 2003 and recognized a non-cash pre-tax charge of $9.0 million ($5.8 million, net of tax) in the first quarter of 2003 as the cumulative effect of change in accounting principle due to adoption of this standard.

FUTURE TRENDS

On December 15, 2004, Noble Energy and Patina entered into the Merger Agreement under the terms of which Noble Energy has agreed to purchase all of the issued and outstanding shares of common stock of Patina. Total consideration for the shares of Patina is fixed at approximately $1.1 billion in cash and approximately 27 million shares of Noble Energy common stock, not including options and warrants exchanged in the transaction. Consummation of the transactions contemplated by the Merger Agreement is conditioned upon, among other things: (1) approval by the stockholders of Noble Energy and Patina; (2) the receipt of all required regulatory approvals; and (3) the effectiveness of a registration statement relating to the shares of Noble Energy common stock to be issued in the proposed merger. It is anticipated that the transaction will be completed early in the second quarter of 2005. There is no impact of the proposed merger on these financial statements.

In connection with the proposed merger, the Company has received a $1.3 billion commitment from certain financial institutions. The new facility will be a reducing revolver due 2010 with a five percent per quarter commitment reduction in each calendar quarter during year four and 20 percent per quarter reduction in year five. The facility will incur a 7.5 basis point “ticking” fee from April 29, 2005 until the effective date of the facility. When the facility becomes effective, the Company will incur a facility fee of 10 to 25 basis points per annum depending upon the Company's credit rating. The facility is to bear interest based upon a Eurodollar rate plus 30 to 100 basis points depending upon the Company's credit rating.

The Company expects crude oil and natural gas production from continuing operations to increase in 2005 compared to 2004. The increased production is expected primarily from the continued expansion of natural gas markets in Israel, a full year of production from Phase 2A, the Phase 2B expansion of the LPG plant in Equatorial Guinea and new deepwater wells in the Gulf of Mexico. The Company's production profile may be impacted by several factors, including:

- The timing of the production increases from Phase 2B in Equatorial Guinea and deepwater developments in the Gulf of Mexico during 2005;
- Seasonal variations in rainfall in Ecuador that affect the Company's natural gas-to-power project; and
- Potential weather-related shut-ins in the U.S. Gulf of Mexico and Gulf Coast areas.

The Company recently set its 2005 capital expenditures budget at approximately $735.0 million, excluding possible asset purchases or the previously announced proposed merger with Patina. The Company plans to fund such expenditures primarily from cash flows from operations. 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.

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 periodically enters into crude oil and natural gas commodity hedges as a means to help reduce commodity price volatility. The Company cannot predict the extent to which its revenues will be affected by inflation, government regulation or changing prices.

Impact of Recently Issued Accounting Pronouncements

Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 – In May 2004, the Financial Accounting Standards Board ("FASB") issued Financial Staff Position ("FSP") FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," ("FSP FAS 106-2"). The adoption of FSP FAS 106-2 had no impact on the Company's financial position, results of operations or cash flows because the Company's postretirement benefit plans, as currently structured, do not provide prescription drug benefits that qualify for the subsidy under the Act.

Accounting for Costs Associated with Mineral Rights – During 2003, a reporting issue arose regarding the application of certain provisions of SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," to companies in the extractive industries, including oil and gas companies. The issue was whether SFAS No. 142 required registrants to classify the costs of mineral rights associated with extracting crude oil and natural gas as intangible assets on the balance sheet, apart from other capitalized oil and gas property costs, and provided specific footnote disclosures. In September 2004, the FASB issued FSP FAS 142-2, "Application of FASB Statement No. 142, Goodwill and Other Intangible Assets*,* to Oil- and Gas-Producing Entities," ("FSP FAS 142-2"). FSP FAS 142-2 indicates that the scope exception in paragraph 8(b) of SFAS No. 142 includes the balance sheet classification and disclosures for drilling and mineral rights of oil- and gas-producing entities that are within the scope of SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." The adoption of FSP FAS 142-2 had no effect on the Company's balance sheet, results of operations or cash flows as, historically, the Company has included the costs of mineral rights associated with extracting crude oil and natural gas as a component of oil and gas properties in accordance with SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies."

Accounting for Income Taxes – On October 22, 2004, the American Jobs Creation Act of 2004 ("the AJCA") became law. The AJCA included numerous provisions that may materially affect accounting for income taxes. Those provisions include a repeal of an export tax benefit for U.S.-based manufacturing activities and grants a special deduction that, depending on the circumstances, could reduce the effective tax rate. In addition, the AJCA created a temporary incentive for U.S. corporations to repatriate accumulated income earned abroad by providing for an 85 percent dividends received deduction for certain dividends from controlled foreign corporations. The deduction is subject to a number of limitations and, to date, uncertainty remains as to how to interpret some provisions of the AJCA. Two issues have arisen relating to accounting for the income tax effects of the AJCA: (1) whether the deduction on qualified production activities should be accounted for as a special deduction or a tax rate reduction under FAS No. 109, "Accounting for Income Taxes," and (2) whether an enterprise should be allowed additional time beyond the financial reporting period in which the AJCA was enacted to evaluate the effects of the act on its plan for reinvestment or repatriation of both current and prior years' unremitted foreign earnings for purposes of applying SFAS No. 109.

In December 2004, the FASB issued two staff positions regarding these issues:

FSP FAS 109-1, "Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004" stated that the staff believes that the qualified production activities deduction should be accounted for as a special deduction in accordance with SFAS No. 109. The Company will account for any qualified production activities deduction as a special deduction in 2005 and believes that because of the phased-in nature of the deduction, it will not have significant impact on its income tax provision or deferred tax assets or liabilities.

FSP FAS 109-2, "Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision with the American Jobs Creation Act of 2004" stated that the staff believes that the lack of clarification of certain provisions within the AJCA and the timing of the enactment necessitate a practical exception to the SFAS No. 109 requirement to reflect in the period of enactment the effect of a new tax law. Accordingly, an enterprise is allowed time beyond the financial reporting period of enactment to evaluate the effect of the act on its plan for reinvestment or repatriation of foreign earnings for purposes of applying SFAS No. 109. The Company has begun an evaluation of the effects of the repatriation provision. However, due to uncertainty remaining as to how to interpret some provisions of the AJCA, the Company is not yet in a position to decide on whether, and to what extent, it might repatriate foreign earnings that have not yet been remitted to the U.S. The Company is currently evaluating the possibility of repatriating earnings of its U.K. subsidiaries ranging in amount from $60 million to $125 million, with a respective tax liability ranging from $3.1 million to $6.6 million. The Company expects to be in a position to finalize its assessment by second quarter 2005. If management decides to repatriate a portion of its foreign earnings pursuant to the AJCA, the Company will reflect additional taxes on those earnings for the period in which that decision is made.

Accounting for Nonmonetary Asset Exchanges – In December 2004, the FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29, Accounting for Nonmonetary Transactions." SFAS No. 153 requires that nonmonetary exchanges be accounted for at fair value, recognizing any gain or loss, if the transaction meets a commercial-substance criterion and fair value is determinable. SFAS No. 153 is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The provisions are to be applied prospectively, although earlier application is permitted for nonmonetary asset exchanges occurring in fiscal periods beginning after the date of issuance. The Company expects to adopt SFAS No. 153 during third quarter 2005 for nonmonetary asset exchanges occurring on or after July 1, 2005.

Accounting for Stock Options – In December 2004, the FASB issued SFAS No. 123(R), "Share-Based Payment." This statement is a revision of SFAS No. 123, "Accounting for Stock-Based Compensation," and supersedes Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees," and its related implementation guidance. SFAS No. 123(R) requires companies to recognize in the income statement the grant-date fair value of stock options and other equity-based compensation issued to employees and is effective for interim or annual periods beginning after June 15, 2005. The Company expects to adopt SFAS No. 123(R) as of July 1, 2005, using the modified prospective transition method. Under the modified prospective method, awards that are granted, modified or settled after the date of adoption will be measured in accordance with SFAS No. 123(R). Unvested equity-classified awards that were granted prior to July 1, 2005 will be accounted for in accordance with SFAS No. 123, except that the amounts will be recognized on the Company's consolidated statements of operations. The Company is currently evaluating the adoption of SFAS No. 123(R) and expects that it will recognize additional compensation expense for third quarter 2005.

Accounting for Suspended Well Costs – During 2004, an issue arose for companies using the successful efforts method of accounting for exploration and production activities regarding the application of certain guidance in SFAS No. 19. Paragraph 19 of SFAS No. 19 requires costs of drilling exploratory wells to be capitalized pending determination of whether the well has found proved reserves. If the well found proved reserves, the capitalized costs become part of the entity's wells, equipment and facilities; if, however, the well has not found proved reserves, the capitalized costs of drilling the wells are expensed, net of any salvage value. Questions have arisen in practice about the application of this guidance due to changes in oil and gas exploration processes and life cycles. The issue is whether there are circumstances that would permit the continued capitalization of exploratory well costs beyond one year other than when additional exploration wells are necessary to justify major capital expenditures and those wells are underway or firmly planned for the near future. In response, the FASB has issued a proposed Staff Position, FSP FAS 19-a, "Accounting for Suspended Well Costs," to address this issue. FSP FAS 19-a proposes to amend the guidance for suspended wells to address circumstances that would permit the continued capitalization of exploratory well costs beyond one year other than when additional exploration wells are necessary to justify major capital expenditures and those wells are underway or firmly planned for the near future. For more information, see "Item 8. Financial Statements and Supplementary Data—Note 5 - Capitalized Exploratory Well Costs" of this Form 10-K.

Item 7a. Quantitative and Qualitative Disclosures About Market Risk.

Derivative Instruments Held for Non-Trading Purposes – 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 has used derivative hedging instruments and may do so in the future as a means of managing its exposure to price changes. Such instruments include fixed price contracts, variable to fixed price swaps, costless collars and other contractual arrangements.

During 2004, 2003 and 2002, the Company entered into various crude oil and natural gas fixed price swaps and costless collars related to its crude oil and natural gas production. The tables below summarize the various transactions.

Natural Gas	**2004**	**2003**	**2002**
Hedge MMBTUpd	120,284	190,038	170,274
Floor price range	$3.75 - $5.00	$3.25 - $3.80	$2.00 - $3.50
Ceiling price range	$5.16 - $9.65	$4.00 - $5.25	$2.45 - $5.10
Percent of daily production	33%	56%	50%
Gain (loss) per Mcf	$(.08)	$(.44)	$.05

Crude Oil	**2004**	**2003**	**2002**
Hedge Bpd	16,261	15,793	5,247
Floor price range	$24.00 - $37.50	$23.00 - $27.00	$23.00 - $24.00
Ceiling price range	$30.00 - $54.00	$27.20 - $35.05	$29.30 - $30.10
Percent of daily production	36%	44%	18%
Loss per Bbl	$(3.05)	$(1.01)	$(.02)

During 2004, 2003 and 2002, no gains or losses were reclassified into earnings as a result of the discontinuance of hedge accounting treatment. During 2004, 2003 and 2002, the Company's ineffectiveness related to its cash flow hedges was de minimis.

As of December 31, 2004, the Company had entered into costless collars related to its natural gas and crude oil production as follows:

Natural Gas				Crude Oil			
		Average Price Per MMBTU				Average Price Per Bbl	
Production Period	MMBTUpd	Floor	Ceiling	Production Period	Bopd	Floor	Ceiling
2005	79,932	$ 5.07	$ 7.82	2005	20,519	$ 31.56	$ 43.71
2006	3,699	$ 5.00	$ 8.00	2006	1,865	$ 29.00	$ 34.93

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 scheduled 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 scheduled trading day applicable for each calculation period is more than the ceiling price. The amount payable by the Company, 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 counterparty, 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.

As of December 31, 2004, the Company had entered into fixed price swaps related to its natural gas and crude oil production as follows:

Natural Gas			Crude Oil		
Production Period	MMBTUpd	Average Price Per MMBTU	Production Period	Bopd	Average Price Per Bbl
2005	53,699	$ 6.63	2005	6,443	$ 39.24
2006	130,000	$ 6.39	2006	10,600	$ 39.98
2007	130,000	$ 5.95	2007	11,100	$ 39.02
2008	130,000	$ 5.59	2008	10,500	$ 38.16

Subsequent to December 31, 2004, the Company entered into fixed price swaps related to its natural gas and crude oil production as follows:

Natural Gas			Crude Oil		
Production Period	MMBTUpd	Average Price Per MMBTU	Production Period	Bopd	Average Price Per Bbl
2005	13,425	$ 6.50	2005	2,349	$ 40.66
2006	20,000	$ 6.40	2006	6,000	$ 41.33
2007	20,000	$ 5.98	2007	6,000	$ 39.50
2008	20,000	$ 5.65	2008	6,000	$ 38.35

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 scheduled trading day applicable for each calculation period is less than the fixed price. The Company would pay the counterparty if the settlement price for the scheduled trading day applicable for each calculation period is more than the fixed price. The amount payable by the Company, if the floating price is above the fixed price, is the product of the notional quantity per calculation period and the excess, if any, of the floating price over the fixed price in respect of each calculation period. The amount payable by the counterparty, if the floating price is below the fixed price, is the product of the notional quantity per calculation period and the excess, if any, of the fixed price over the floating price in respect of each calculation period.

In connection with the announcement of the Merger Agreement, in order to reduce the price sensitivity associated with future crude oil and natural gas prices, Noble Energy entered into additional derivative transactions ("hedges"), which are included in the tables above, using its own production that was available to be hedged. The natural gas hedges totaled 100,000 MMBTUpd starting in May 2005 through December 2005 and 150,000 MMBTUpd for 2006 through 2008. The crude oil hedges totaled 13,100 Bopd starting in May 2005 through December 2005 and approximately 16,700 Bopd for 2006 through 2008. These hedges consist of fixed price swaps that average $6.07 per MMBTU for natural gas and $39.30 per barrel of oil. Prior to closing of the proposed merger, Noble Energy may enter into additional derivative transactions using its existing production. The Merger Agreement provides that if Noble Energy terminates the Merger Agreement within three business days of receiving notification that the Patina Board of Directors has made an adverse recommendation change, or resolved to make such a change (in either case for any reason other than a superior proposal), Patina would be required to reimburse Noble Energy for up to $45.0 million of actual losses realized by Noble Energy with respect to certain hedges for the years 2006 through 2008.

As of December 31, 2004, the Company had a net unrealized loss of $11.4 million related to crude oil and natural gas derivative instruments entered into for non-trading purposes. Included in the net unrealized loss is $.7 million of ineffectiveness.

Accumulated Other Comprehensive Income/(Loss) – As of December 31, 2004 and 2003, the balance in AOCI included net deferred losses of $6.9 million and $7.6 million, respectively, related to crude oil and natural gas derivative instruments accounted for as cash flow hedges. The net deferred losses are net of deferred income tax benefit of $3.7 million and $4.1 million, respectively.

If commodity prices were to stay the same as they were at December 31, 2004, approximately $22.3 million of deferred losses related to the fair values of crude oil and natural gas derivative instruments included in AOCI at December 31, 2004 would be reclassified to earnings during the next twelve months as the forecasted transactions occur, and would be recorded as a reduction in oil and gas sales and royalties. Any actual increase or decrease in revenues will depend upon market conditions over the period during which the forecasted transactions occur. All current crude oil and natural gas derivative instruments are designated as cash flow hedges.

Derivative Instruments Held for Trading Purposes – In addition to the derivative instruments pertaining to the Company's production as described above, NEMI, from time to time, employs various derivative instruments in connection with its purchases and sales of third-party production to lock in profits or limit exposure to natural 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.

NEMI records gains and losses on derivative instruments using mark-to-market accounting. Under this accounting method, the changes in the market value of outstanding financial instruments are recognized as gains or losses in the period of change. NEMI recorded a gain of less than $.1 million, a loss of $.2 million and a gain of $.9 million in GMP proceeds during 2004, 2003 and 2002, respectively, related to derivative instruments entered into for trading purposes. As of December 31, 2004, NEMI had a net receivable of $.6 million related to derivative instruments entered into for trading purposes.

Receivables/Payables Related to Crude Oil and Natural Gas Derivative Instruments – At December 31, 2004, the Company's consolidated balance sheet included a receivable of $49.2 million (of which $28.7 million is current) and a payable of $60.0 million (of which $50.3 million is current) related to crude oil and natural gas derivative instruments. At December 31, 2003, the Company's consolidated balance sheet included a receivable of $56.1 million (of which $48.1 million is current) and a payable of $67.2 million (of which $59.8 million is current) related to crude oil and natural gas derivative instruments.

Interest Rate Risk

The Company is exposed to interest rate risk related to its variable and fixed interest rate debt. As of December 31, 2004, the Company had $885.0 million of debt outstanding of which $650.0 million was fixed-rate debt. The Company believes that anticipated near term changes in interest rates will not have a material effect on the fair value of the Company's fixed-rate debt and will not expose the Company to the risk of earnings or cash flow loss.

The remainder of the Company's debt at December 31, 2004 was variable-rate debt and, therefore, exposes the Company to the risk of earnings or cash flow loss due to changes in market interest rates. At December 31, 2004, $235.0 million of variable-rate debt was outstanding. A 10 percent change in the floating interest rates applicable to the December 31, 2004 balance would result in a change in annual interest expense of $.7 million.

The Company occasionally enters into forward contracts or swap agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate swaps or interest rate "locks" used as cash flow hedges are reported in AOCI, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense. At December 31, 2004, AOCI included $4.6 million, net of tax, related to a settled interest rate lock. This amount is being reclassified into earnings as adjustments to interest expense over the term of the unsecured notes.

Foreign Currency Risk

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. Transaction 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. Transaction gains or losses are included in other expense/(income) on the statements of operations.

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. 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.

Other. 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, terrorist acts and civil disturbances; expropriation or nationalization of assets; renegotiation, modification or nullification of existing contracts; changes in taxation policies; laws and policies of the U.S. affecting foreign investment, taxation, trade and business conduct; foreign exchange restrictions; international monetary fluctuations; and other hazards arising out of foreign governmental sovereignty over areas in which the Company conducts operations.

Item 8. Financial Statements and Supplementary Data.

INDEX TO FINANCIAL STATEMENTS

Consolidated Financial Statements of Noble Energy, Inc.

Management's Report on Internal Control over Financial Reporting

Report of Independent Registered Public Accounting Firm on the Financial Statements

Report of Independent Registered Public Accounting Firm on Internal Control over Financial Reporting

Consolidated Balance Sheets as of December 31, 2004 and 2003

Consolidated Statements of Operations for each of the three years in the period ended December 31, 2004

Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 2004

Consolidated Statements of Shareholders' Equity and Other Comprehensive Income for each of the three years in the period ended December 31, 2004

Notes to Consolidated Financial Statements

Supplemental Oil and Gas Information (Unaudited)

Supplemental Quarterly Financial Information (Unaudited)

Financial Statements of Atlantic Methanol Production Company, LLC

Report of Independent Registered Public Accounting Firm

Report of Independent Auditors

Balance Sheets as of December 31, 2004 and 2003

Statements of Income for each of the three years in the period ended December 31, 2004

Statements of Members' Equity for each of the three years in the period ended December 31, 2004

Statements of Cash Flows for each of the three years in the period ended December 31, 2004

Notes to Financial Statements

Management's Report on Internal Control over Financial Reporting

The management of Noble Energy is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2004, management assessed the effectiveness of the Company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in "Internal Control — Integrated Framework," issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2004, based on those criteria.

KPMG LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004. The report expresses unqualified opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting as of December 31, 2004.

Noble Energy, Inc.

Report of Independent Registered Public Accounting Firm

The Shareholders and Board of Directors of
Noble Energy, Inc.:

We have audited the accompanying consolidated balance sheets of Noble Energy, Inc. and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of operations, shareholders' equity and other comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2004. These consolidated 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 audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (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 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, 2004 and 2003, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Noble Energy, Inc.'s internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 11, 2005 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Houston, Texas
March 11, 2005

Report of Independent Registered Public Accounting Firm

The Shareholders and Board of Directors of
Noble Energy, Inc.:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Noble Energy, Inc. maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Noble Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Noble Energy, Inc. maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on criteria established in Internal Control — Integrated Framework issued by COSO. Also, in our opinion, Noble Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control — Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Noble Energy, Inc. and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of operations, shareholders' equity and other comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2004, and our report dated March 11, 2005 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Houston, Texas
March 11, 2005

CONSOLIDATED BALANCE SHEETS
NOBLE ENERGY, INC. AND SUBSIDIARIES

(in thousands, except share amounts)	December 31, 2004	December 31, 2003
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 179,794	$ 62,374
Accounts receivable - trade, net	407,349	303,822
Derivative instruments	28,733	48,086
Materials and supplies inventories	12,109	11,083
Deferred taxes	13,039	7,501
Prepaid expenses and other	28,278	16,304
Probable insurance claims	65,000	
Assets held for sale		21,245
Total current assets	734,302	470,415
Property, Plant and Equipment, at Cost:		
Oil and gas mineral interests, equipment and facilities (successful efforts method of accounting)	4,292,561	3,875,598
Other	56,707	49,389
	4,349,268	3,924,987
Accumulated depreciation, depletion and amortization	(2,016,318)	(1,825,246)
Total property, plant and equipment, net	2,332,950	2,099,741
Investment in Unconsolidated Subsidiaries	231,795	227,669
Other Assets	144,124	44,824
Total Assets	$ 3,443,171	$ 2,842,649
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable - trade	$ 431,521	$ 388,428
Derivative instruments	50,304	59,750
Interest payable	11,439	11,324
Income taxes - current	64,852	6,548
Asset retirement obligation - current	79,568	1,023
Other current liabilities	27,320	27,182
Current installments of long-term debt		153,674
Total current liabilities	665,004	647,929
Deferred Income Taxes	183,351	163,146
Asset Retirement Obligation	175,415	101,804
Other Deferred Credits and Noncurrent Liabilities	79,157	80,176
Long-term Debt	880,256	776,021
Total Liabilities	$ 1,983,183	$ 1,769,076
Commitments and Contingencies		
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; 62,572,417 and 60,744,583 shares issued in 2004 and 2003, respectively	208,576	202,480
Capital in excess of par value	500,034	431,208
Deferred compensation	(1,671)	
Accumulated other comprehensive loss	(14,787)	(10,886)
Retained earnings	843,792	526,727
	1,535,944	1,149,529
Less common stock in treasury at cost (December 31, 2004 and 2003, 3,549,976 shares)	(75,956)	(75,956)
Total shareholders' equity	1,459,988	1,073,573
Total Liabilities and Shareholders' Equity	$ 3,443,171	$ 2,842,649

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF OPERATIONS

NOBLE ENERGY, INC. AND SUBSIDIARIES

(in thousands, except per share amounts)	Year ended December 31, 2004	2003	2002
Revenues:			
Oil and gas sales and royalties	$ 1,174,199	$ 839,144	$ 609,026
Gathering, marketing and processing	49,250	68,158	64,517
Electricity sales	58,627	58,022	18,257
Income from investment in unconsolidated subsidiaries	69,100	40,626	9,532
Total Revenues	1,351,176	1,005,950	701,332
Costs and Expenses:			
Oil and gas operations	158,695	123,114	88,201
Production and ad valorem taxes	28,022	22,722	17,157
Transportation	18,553	14,679	16,441
Oil and gas exploration	117,001	148,818	150,701
Gathering, marketing and processing	37,699	59,114	53,982
Electricity generation	47,788	50,846	15,946
Depreciation, depletion and amortization	308,855	309,343	236,881
Impairment of operating assets	9,885	31,937	
Selling, general and administrative	59,091	52,466	47,664
Accretion of discount on asset retirement obligation	9,352	9,331	
Loss on involuntary conversion of assets	1,000		
Interest	61,628	61,111	64,040
Interest capitalized	(13,401)	(14,134)	(16,331)
Other expense/(income), net	(9,033)	(5,036)	(1,246)
Total Costs and Expenses	835,135	864,311	673,436
Income Before Taxes	516,041	141,639	27,896
Income Tax Provision	202,191	51,747	19,801
Income From Continuing Operations	313,850	89,892	8,095
Discontinued Operations, Net of Tax	14,860	(6,061)	9,557
Cumulative Effect of Change in Accounting Principle, Net of Tax		(5,839)	
Net Income	$ 328,710	$ 77,992	$ 17,652
Basic Earnings (Loss) Per Share:			
Income from continuing operations	$ 5.39	$ 1.58	$ 0.14
Discontinued operations, net of tax	$ 0.25	$ (0.11)	$ 0.17
Cumulative effect of change in accounting principle, net of tax	$	$ (0.10)	$
Net Income	$ 5.64	$ 1.37	$ 0.31
Diluted Earnings (Loss) Per Share:			
Income from continuing operations	$ 5.30	$ 1.56	$ 0.14
Discontinued operations, net of tax	$ 0.25	$ (0.10)	$ 0.17
Cumulative effect of change in accounting principle, net of tax	$	$ (0.10)	$
Net Income	$ 5.55	$ 1.36	$ 0.31
Weighted Average Shares Outstanding:			
Basic	58,275	56,964	57,196
Diluted	59,226	57,539	57,763

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
NOBLE ENERGY, INC. AND SUBSIDIARIES

(in thousands)	Year ended December 31, 2004	2003	2002
Cash Flows from Operating Activities:			
Net income	$ 328,710	$ 77,992	$ 17,652
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization - oil and gas production	308,855	309,343	236,881
Depreciation, depletion and amortization - electricity generation	19,550	27,116	8,458
Loss on involuntary conversion of assets	1,000		
Dry hole expense	46,192	63,637	81,396
Amortization of unproved leasehold costs	19,280	33,380	21,254
Non-cash effect of discontinued operations	(14,996)	87,933	48,405
(Gain) loss on disposal of assets	(13,296)	17,978	(106)
Deferred income taxes	20,205	(31,475)	20,856
Accretion of asset retirement obligation	9,352	9,331	
Income from unconsolidated subsidiaries	(69,100)	(40,626)	(9,532)
Dividends received from unconsolidated subsidiary	57,825	46,125	17,696
Impairment of operating assets	9,885	31,937	
Cumulative effect of change in accounting principle, net of tax		5,839	
(Increase) decrease in other	(18,389)	(10,830)	5,132
Changes in operating assets and liabilities, not including cash:			
(Increase) in accounts receivable	(110,365)	(70,898)	(49,945)
(Increase) decrease in other current assets	(18,538)	16,849	21,972
Increase in accounts payable	43,093	36,572	81,764
Increase (decrease) in other current liabilities	88,923	(7,433)	5,072
Net Cash Provided by Operating Activities	708,186	602,770	506,955
Cash Flows from Investing Activities:			
Capital expenditures	(660,851)	(527,386)	(595,739)
Proceeds from sale of property, plant and equipment	62,455	81,084	20,363
Distribution from unconsolidated subsidiaries	7,149	1,500	5,500
Investment in unconsolidated subsidiaries			(7,652)
Insurance recovery - involuntary conversion	3,146		
Net Cash Used in Investing Activities	(588,101)	(444,802)	(577,528)
Cash Flows from Financing Activities:			
Exercise of stock options	62,591	24,685	7,692
Cash dividends paid	(11,646)	(9,755)	(9,147)
Issuance of long-term debt	197,688		
Payment on credit facilities, net	(244,753)	(49,825)	(25,000)
Proceeds from term loan	150,000	434	68,667
Repayment of Israel note	(20,746)	(36,369)	(9,927)
Repayment of note payable	(7,928)	(3,580)	(19,507)
Repayment of AMCCO note	(127,871)		
Repayment of treasury stock obligation		(36,626)	
Net Cash (Used in) Provided by Financing Activities	(2,665)	(111,036)	12,778
Increase (Decrease) in Cash and Cash Equivalents	117,420	46,932	(57,795)
Cash and Cash Equivalents at Beginning of Year	62,374	15,442	73,237
Cash and Cash Equivalents at End of Year	$ 179,794	$ 62,374	$ 15,442
Supplemental Disclosures of Cash Flow Information:			
Cash paid during the year for:			
Interest (net of amount capitalized)	$ 33,235	$ 31,824	$ 31,303
Income taxes paid (refunded)	$ 112,250	$ 55,500	$ (40,394)
Non-cash financing and investing activities:			
Treasury stock and note obligation	$	$ 36,626	$

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND OTHER COMPREHENSIVE INCOME

NOBLE ENERGY, INC. AND SUBSIDIARIES

(in thousands, except common stock)	Comprehensive Income (Loss)	Common Stock Shares Issued	Common Stock Amount	Capital in Excess of Par Value	Deferred Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock At Cost	Total Shareholders' Equity
December 31, 2001		59,511,323	$ 198,369	$ 396,104		$ 449,985	$ 5,070	$ (39,330)	$ 1,010,198
Net Income	$ 17,652					17,652			17,652
Change in fair value of cash flow hedges, net of $(10,611) tax	(19,707)						(19,707)		(19,707)
Change in additional minimum liability and other, net of $18 tax	34						34		34
Exercise of stock options		356,744	1,189	9,167					10,356
Cash dividends ($.16 per share)						(9,147)			(9,147)
Total	$ (2,021)								
December 31, 2002		59,868,067	$ 199,558	$ 405,271		$ 458,490	$ (14,603)	$ (39,330)	$ 1,009,386
Net Income	$ 77,992					77,992			77,992
Change in fair value of cash flow hedges, net of $2,428 tax	4,510						4,510		4,510
Change in additional minimum liability and other, net of $(427) tax	(793)						(793)		(793)
Exercise of stock options		876,516	2,922	25,937					28,859
Cash dividends ($.17 per share)						(9,755)			(9,755)
Treasury stock purchase								(36,626)	(36,626)
Total	$ 81,709								
December 31, 2003		60,744,583	$ 202,480	$ 431,208		$ 526,727	$ (10,886)	$ (75,956)	$ 1,073,573
Net Income	$ 328,710					328,710			328,710
Change in fair value of cash flow hedges, net of $(748) tax	(1,390)						(1,390)		(1,390)
Change in additional minimum liability and other, net of $(1,352) tax	(2,511)						(2,511)		(2,511)
Issuance of restricted stock		41,191	141	2,399	(2,540)				
Deferred compensation included in net income					869				869
Exercise of stock options		1,786,643	5,955	66,428					72,383
Cash dividends ($.20 per share)						(11,646)			(11,646)
Total	$ 324,809								
December 31, 2004		62,572,417	$ 208,576	$ 500,034	$ (1,671)	$ 843,792	$ (14,787)	$ (75,956)	$ 1,459,988

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 - 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 and Texas); the Mid-continent Region (Oklahoma and Kansas); and the Rocky Mountain Region (Colorado, Montana, Nevada, Wyoming and California). The international areas of operations include Argentina, China, Ecuador, Equatorial Guinea, the Mediterranean Sea (Israel) and the North Sea (the Netherlands and the United Kingdom). The Company also markets domestic crude oil and natural gas production through NEMI.

Pending Merger with Patina Oil & Gas Corporation

On December 15, 2004, the Boards of Directors of Noble Energy and Patina approved Noble Energy's Merger Agreement with Patina. As a result of the proposed merger, Patina will merge into a wholly-owned subsidiary of Noble Energy, and Patina shareholders will receive aggregate consideration comprised of approximately 60 percent Noble Energy common stock and 40 percent cash. Total consideration for the outstanding shares of Patina is fixed at approximately $1.1 billion in cash and approximately 27 million Noble Energy shares, not including options and warrants exchanged in the transaction, and subject to adjustment as provided in the Merger Agreement. Under the terms of the Merger Agreement, Patina shareholders will have the right to elect to receive either cash or Noble Energy common stock, or a combination thereof, in exchange for their shares of Patina common stock, subject to an allocation mechanism if either the cash election or the stock election is oversubscribed. While the per share consideration was initially set in the Merger Agreement at $37.00 in cash or .6252 shares of Noble Energy common stock, the per share consideration is subject to adjustment upwards or downwards. This adjustment will reflect 37.5126 percent of the difference between $59.18 and the price of Noble Energy's shares during a specified period prior to closing. In addition, the per share consideration is adjusted so that each Patina share receives consideration representing equal value regardless of whether it is converted into cash or Noble Energy common stock. The proposed merger is subject to the approval of the shareholders of Noble Energy and Patina and other customary conditions. The proposed merger is expected to be completed in the second quarter of 2005.

Note 2 - Summary of Significant Accounting Policies

Basis of Presentation and Consolidation

Accounting policies used by Noble Energy, Inc. and its subsidiaries conform to accounting principles generally accepted in the United States of America. The more significant of such policies are 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"). All significant intercompany balances and transactions have been eliminated upon consolidation.

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 crude oil and natural gas 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. Company engineers in the Houston office perform all reserve estimates for the Company's different geographical regions. These reserve estimates are reviewed and approved by corporate engineering staff with final approval by the Senior Vice President of Production and Drilling. For more information, see "Supplemental Oil and Gas Information" of this Form 10-K.

Other items subject to estimates and assumptions include the carrying amount of property, plant and equipment; asset retirement obligations; valuation allowances for receivables and deferred income tax assets; valuation of derivative instruments; and assets and obligations related to employee benefits. Actual results could differ from those estimates.

Foreign Currency

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 remeasured to U.S. dollars and recorded in the financial statements. Transaction gains or losses were not material in any of the periods presented and are included in other income on the statements of operations.

Allowance for Doubtful Accounts

The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectibility and accrues a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of any reserve may be reasonably estimated.

The following table presents the activity of the Company's allowance for doubtful accounts for each of the three years:

	Year Ended December 31,		
(dollars in thousands)	**2004**	**2003**	**2002**
Balance at beginning of the period	$ 6,255	$ 1,510	$ 638
Charged to expense	6,838	4,745	872
Deductions			
Balance at end of the period	$ 13,093	$ 6,255	$ 1,510

During 2004, the allowance was increased by $5.4 million to reflect additional collection allowances resulting from higher power prices in Ecuador and $1.4 million to record various provisions related to the Company's domestic business. During 2003, the allowance increased to reflect additional collection allowance related to financial derivative contracts with one of the Company's counterparties.

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. 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 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. Repairs and maintenance are expensed as incurred.

Geological and geophysical costs, delay rentals and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. Except as noted below, the Company does not carry the costs of drilling an exploratory well as an asset for more than one year following completion of drilling unless the exploratory well finds crude oil and/or natural gas reserves in an area requiring a major capital expenditure and (1) the well has found sufficient quantity of reserves to justify its completion as a producing well if the required capital expenditure is made and (2) drilling of the additional exploratory wells is under way or firmly planned for the near future. For certain capital-intensive deepwater Gulf of Mexico or international projects, it may take the Company more than one year to evaluate the future potential of the exploration well and make a determination of its economic viability. The Company's ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond the Company's control. In such cases, exploratory well costs remain suspended as long as the Company is actively pursuing such permits and approvals and believes they will be obtained. Management continuously monitors suspended exploratory well costs until a decision can be made that the well has found proved reserves or is noncommercial and is impaired. For more information, see "Note 5 - Capitalized Exploratory Well Costs" of this Form 10-K.

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the Company reviews oil and gas properties and other long-lived assets for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or commodity prices. The Company estimates the future cash flows expected in connection with the properties and compares such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. When the carrying amounts of the properties exceed their estimated undiscounted future cash flows, the carrying amount of the properties is written down to their fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices, and timing of future production, future capital expenditures and a risk-adjusted discount rate.

The Company recorded $9.9 million of impairments in 2004, primarily related to downward reserve revisions on two domestic properties. The Company recorded $31.9 million of impairments in 2003, primarily related to a reserve revision on the East Cameron 338 field in the Gulf of Mexico after recompletion and remediation activities produced less-than-expected results. There were no impairments in 2002.

Other property includes autos, trucks, airplane, office furniture and computer equipment and other fixed assets. These items are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets or group of assets.

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 to bring them to a condition and location necessary for their intended use.

Statement of Cash Flows

For purposes of reporting cash flows, cash and cash equivalents 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:

	2004		2003		2002	
(in thousands except per share amounts)	**Income (Numerator)**	**Shares (Denominator)**	**Income (Numerator)**	**Shares (Denominator)**	**Income (Numerator)**	**Shares (Denominator)**
Net income/shares	$ 328,710	58,275	$ 77,992	56,964	$ 17,652	57,196
Basic EPS	$ 5.64		$ 1.37		$ .31	
Net income/shares	$ 328,710	58,275	$ 77,992	56,964	$ 17,652	57,196
Effect of Dilutive Securities						
Stock options		912		575		567
Restricted stock		39				
Adjusted net income and shares	$ 328,710	59,226	$ 77,992	57,539	$ 17,652	57,763
Diluted EPS	$ 5.55		$ 1.36		$ .31	

The table below reflects the number of options excluded from the EPS calculation above for 2003 and 2002, as they were antidilutive. There were no antidilutive options for 2004 as the average market price of Company common stock for that period was greater than the exercise price for all options outstanding.

	2004	2003	2002
Options excluded from dilution calculation	None	1,533,290	2,229,978
Range of exercise prices		\$37.63 - \$43.21	\$35.40 - \$43.21
Weighted average exercise price		\$41.10	\$39.77

Accounting for Stock-Based Compensation

At December 31, 2004, the Company had two stock-based compensation plans, which are described more fully in "Note 9 - Stock Options, Restricted Stock 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, no stock-based 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 pro forma 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 compensation.

(in thousands except per share amounts)	2004	2003	2002
Net income, as reported	$ 328,710	$ 77,992	$ 17,652
Add: Stock-based compensation cost recognized, net of related tax benefit	599	153	418
Deduct: Total stock-based compensation expense determined under fair value based method for all awards, net of related tax benefit	(7,926)	(10,022)	(9,934)
Pro forma net income	$ 321,383	$ 68,123	$ 8,136
Earnings per share:			
Basic - as reported	$ 5.64	$ 1.37	$ .31
Basic - pro forma	$ 5.51	$ 1.20	$ .14
Diluted - as reported	$ 5.55	$ 1.36	$ .31
Diluted - pro forma	$ 5.43	$ 1.18	$ .14

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 2004, 2003 and 2002, respectively, as follows:

(amounts expressed in percentages)	2004	2003	2002
Interest rate	4.82	5.07	4.78
Dividend yield	.32	.38	.43
Expected volatility	21.41	28.38	40.26
Expected life (in years)	9.58	9.42	9.73

The weighted average fair value of options granted using the Black-Scholes option pricing model for 2004, 2003 and 2002, respectively, is as follows:

	2004	2003	2002
Black-Scholes model weighted average fair value option price	$ 18.54	$ 16.64	$ 18.14

Revenue Recognition and Imbalances

The Company records revenues from the sales of crude oil, natural gas and methanol when the product is delivered at a fixed or determinable price, title has transferred and collectibility is reasonably assured.

When the Company has an interest with other producers in properties from which natural gas is produced, the Company uses the entitlements method to account for any imbalances. Imbalances occur when the Company sells more or less product than it is entitled to under its ownership percentage. Revenue is recognized only on the entitlement percentage of volumes sold. Any amount sold by the Company in excess of its entitlement is treated as a liability. Any amount sold by the Company less than its entitlement is treated as a receivable. The Company records the noncurrent portion of the liability in other deferred credits and noncurrent liabilities, and the current portion of the liability in other current liabilities. The Company records the noncurrent portion of the receivable in other assets and the current portion of the receivable in other current assets. The Company's imbalance liabilities were $16.1 million and $18.8 million at December 31, 2004 and 2003, respectively. The Company's imbalance receivables were $21.2 million and $23.0 million at December 31, 2004 and 2003, respectively.

Revenues derived from electricity generation are recognized when power is transmitted or delivered, the price is fixed and determinable and collectibility is reasonably assured.

NEMI records third-party sales, net of cost of goods sold, as GMP revenues when the product is delivered or the contract is net settled at a fixed or determinable price, title has transferred and collectibility is reasonably assured.

Derivative Instruments and Hedging Activities

The Company uses various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations. Such instruments include fixed price contracts, variable to fixed price swaps, costless collars and other contractual arrangements. Although these derivative instruments expose the Company to credit risk, the Company monitors the creditworthiness of its counterparties and believes that losses from nonperformance are unlikely to occur. However, the Company is not able to predict sudden changes in its counterparties' creditworthiness. Hedging gains and losses related to the Company's crude oil and natural gas production are deferred in other comprehensive income and reclassified to oil and gas sales and royalties when the forecasted production occurs.

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 on the balance sheet as either an asset or liability measured at fair value. This 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 AOCI 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 on the statements of operations, and requires that a company formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

At December 31, 2004, the Company recorded crude oil and natural gas hedge receivables and liabilities of $49.2 million and $60.0 million, respectively, and other comprehensive loss, net of tax, of $6.9 million related to the Company's derivative contracts.

Insurance

The Company has various types of insurance coverages as are customary in the industry that include directors and officers liability, general liability, well control, pollution, terrorism acts, physical damage insurance and business interruption insurance for certain international locations. The Company self-insures, is a shareholder in an industry mutual insurance company and purchases policies from third party insurance providers to cover various risks. The Company believes the coverages and types of insurance are adequate.

The Company self-insures the medical and dental coverage provided to certain of its employees, certain workers' compensation and the first $200,000 of its general liability coverage.

Liabilities are accrued for self-insured claims, or when estimated losses exceed coverage limits, when sufficient information is available to reasonably estimate the amount of the loss.

Unconsolidated Subsidiaries

AMCCO, AMPCO, AMPCO Marketing LLC, AMPCO Services LLC and Samedan Methanol are accounted for using the equity method. Results of operations from these entities are included in the line "Income from investment in unconsolidated subsidiaries" on the consolidated statements of operations.

Through its ownership interest in AMCCO, the Company owns a 45 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-2 senior secured notes due December 15, 2004 to fund construction payments owed in connection with the construction of its methanol plant. These notes were included on the Company's balance sheet at December 31, 2003 and were repaid by the Company during 2004. The Company's investment in the methanol plant is included in investment in unconsolidated subsidiaries. For more information, see "Note 13 - Unconsolidated Subsidiaries" of this Form 10-K.

Electricity Generation - Ecuador Integrated Power Project

The Company, through its subsidiaries, EDC Ecuador Ltd. and MachalaPower Cia. Ltda., has a 100 percent ownership interest in an integrated natural gas-to-power project. The project includes the Amistad natural gas field, offshore Ecuador, which supplies natural gas to fuel the Machala Power Plant located in Machala, Ecuador. The revenues attributable to the natural gas-to-power project are reported in "Electricity Sales" and the expenses (including DD&A) are reported as "Electricity Generation."

Cumulative Effect of Change in Accounting Principle

On January 1, 2003, the Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," and recorded a non-cash charge of $9.0 million ($5.8 million, net of tax) as the cumulative effect of change in accounting principle. For more information, see "Note 6 - Asset Retirement Obligations" of this Form 10-K.

Concentration of Market Risk

During 2004, there was one third-party purchaser that accounted for 12 percent of the annual total crude oil and natural gas sales and royalties. During 2003 and 2002, 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. The Company does not believe that the loss of a major crude oil or natural gas purchaser would have a material effect on the Company.

Reclassification

Certain reclassifications have been made to the 2003 and 2002 consolidated financial statements to conform to the 2004 presentation. These reclassifications are not material to the Company's financial statements.

Recently Issued Pronouncements

Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 – In May 2004, FASB issued FSP FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." The adoption of FSP FAS 106-2 had no impact on the Company's financial position, results of operations or cash flows because the Company's postretirement benefit plans, as currently structured, do not provide prescription drug benefits that qualify for the subsidy under the Act.

Accounting for Costs Associated with Mineral Rights – During 2003, a reporting issue arose regarding the application of certain provisions of SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," to companies in the extractive industries, including oil and gas companies. The issue was whether SFAS No. 142 required registrants to classify the costs of mineral rights associated with extracting crude oil and natural gas as intangible assets on the balance sheet, apart from other capitalized oil and gas property costs, and provided specific footnote disclosures. In September 2004, the FASB issued FSP FAS 142-2, "Application of FASB Statement No. 142, Goodwill and Other Intangible Assets, to Oil- and Gas-Producing Entities," ("FSP FAS 142-2"). FSP FAS 142-2 indicates that the scope exception in paragraph 8(b) of SFAS No. 142 includes the balance sheet classification and disclosures for drilling and mineral rights of oil- and gas-producing entities that are within the scope of SFAS No. 19. The adoption of FSP FAS 142-2 had no effect on the Company's balance sheet, results of operations or cash flows as, historically, the Company has included the costs of mineral rights associated with extracting crude oil and natural gas as a component of oil and gas properties in accordance with SFAS No. 19.

Accounting for Income Taxes – On October 22, 2004, the AJCA became law. The AJCA included numerous provisions that may materially affect accounting for income taxes. Those provisions include a repeal of an export tax benefit for U.S.-based manufacturing activities and grants a special deduction that, depending on the circumstances, could reduce the effective tax rate. In addition, the AJCA created a temporary incentive for U.S. corporations to repatriate accumulated income earned abroad by providing for an 85 percent dividends received deduction for certain dividends from controlled foreign corporations. The deduction is subject to a number of limitations and, to date, uncertainty remains as to how to interpret some provisions of the AJCA. Two issues have arisen relating to accounting for the income tax effects of the AJCA: (1) whether the deduction on qualified production activities should be accounted for as a special deduction or a tax rate reduction under FAS No. 109, "Accounting for Income Taxes," and (2) whether an enterprise should be allowed additional time beyond the financial reporting period in which the AJCA was enacted to evaluate the effects of the act on its plan for reinvestment or repatriation of both current and prior years' unremitted foreign earnings for purposes of applying SFAS No. 109.

In December 2004, the FASB issued two staff positions regarding these issues:

FSP FAS 109-1, "Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004" stated that the staff believes that the qualified production activities deduction should be accounted for as a special deduction in accordance with SFAS No. 109. The Company will account for any qualified production activities deduction as a special deduction in 2005 and believes that because of the phased-in nature of the deduction, it will not have significant impact on its income tax provision or deferred tax assets or liabilities.

FSP FAS 109-2, "Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision with the American Jobs Creation Act of 2004" stated that the staff believes that the lack of clarification of certain provisions within the AJCA and the timing of the enactment necessitate a practical exception to the SFAS No. 109 requirement to reflect in the period of enactment the effect of a new tax law. Accordingly, an enterprise is allowed time beyond the financial reporting period of enactment to evaluate the effect of the act on its plan for reinvestment or repatriation of foreign earnings for purposes of applying SFAS No. 109. The Company has begun an evaluation of the effects of the repatriation provision. However, due to uncertainty remaining as to how to interpret some provisions of the AJCA, the Company is not yet in a position to decide on whether, and to what extent, it might repatriate foreign earnings that have not yet been remitted to the U.S. The Company is currently evaluating the possibility of repatriating earnings of its U.K. subsidiaries ranging in amount from $60 million to $125 million, with a respective tax liability ranging from $3.1 million to $6.6 million. The Company expects to be in a position to finalize its assessment by second quarter 2005. If management decides to repatriate a portion of its foreign earnings pursuant to the AJCA, the Company will reflect additional taxes on those earnings for the period in which that decision is made.

Accounting for Nonmonetary Asset Exchanges – In December 2004, the FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29, Accounting for Nonmonetary Transactions." SFAS No. 153 requires that nonmonetary exchanges be accounted for at fair value, recognizing any gain or loss, if the transaction meets a commercial-substance criterion and fair value is determinable. SFAS No. 153 is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The provisions are to be applied prospectively, although earlier application is permitted for nonmonetary asset exchanges occurring in fiscal periods beginning after the date of issuance. The Company expects to adopt SFAS No. 153 during third quarter 2005 for nonmonetary asset exchanges occurring on or after July 1, 2005.

Accounting for Stock Options – In December 2004, the FASB issued SFAS No. 123(R), “Share-Based Payment.” This statement is a revision of SFAS No. 123, “Accounting for Stock-Based Compensation,” and supersedes APB Opinion No. 25, “Accounting for Stock Issued to Employees,” and its related implementation guidance. SFAS No. 123(R) requires companies to recognize in the income statement the grant-date fair value of stock options and other equity-based compensation issued to employees and is effective for interim or annual periods beginning after June 15, 2005. The Company expects to adopt SFAS No. 123(R) as of July 1, 2005, using the modified prospective transition method. Under the modified prospective method, awards that are granted, modified or settled after the date of adoption will be measured in accordance with SFAS No. 123(R). Unvested equity-classified awards that were granted prior to July 1, 2005 will be accounted for in accordance with SFAS No. 123, except that the amounts will be recognized on the Company’s consolidated statements of operations. The Company is currently evaluating the adoption of SFAS No. 123(R) and expects that it will recognize additional compensation expense for third quarter 2005.

Accounting for Suspended Well Costs – During 2004, an issue arose for companies using the successful efforts method of accounting for exploration and production activities regarding the application of certain guidance in SFAS No. 19. Paragraph 19 of SFAS No. 19 requires costs of drilling exploratory wells to be capitalized pending determination of whether the well has found proved reserves. If the well found proved reserves, the capitalized costs become part of the entity’s wells, equipment and facilities; if, however, the well has not found proved reserves, the capitalized costs of drilling the wells are expensed, net of any salvage value. Questions have arisen in practice about the application of this guidance due to changes in oil and gas exploration processes and life cycles. The issue is whether there are circumstances that would permit the continued capitalization of exploratory well costs beyond one year other than when additional exploration wells are necessary to justify major capital expenditures and those wells are underway or firmly planned for the near future. In response, the FASB has issued a proposed Staff Position, FSP FAS 19-a, “Accounting for Suspended Well Costs,” to address this issue. Proposed FSP FAS 19-a proposes to amend the guidance for suspended wells to address circumstances that would permit the continued capitalization of exploratory well costs beyond one year other than when additional exploration wells are necessary to justify major capital expenditures and those wells are underway or firmly planned for the near future. For more information, see “Note 5 - Capitalized Exploratory Well Costs” of this Form 10-K.

Note 3 - Involuntary Conversion of Assets

In September 2004, Hurricane Ivan moved through the Gulf of Mexico resulting in infrastructure damage at Main Pass 293/305/306. Costs related to clean-up and redevelopment are insured to a limit that the Company believes will allow for restoration of production. The loss of production is not covered by business interruption insurance.

The Company plans to replace the assets that were destroyed by the hurricane and expects that the costs of replacing those assets will be fully recoverable from insurance proceeds, subject to a $1.0 million deductible. The Company will adjust the total gain or loss attributable to the involuntary conversion in the period in which the contingencies related to the replacement costs and related insurance recoveries are resolved. The loss is being treated as an involuntary conversion for federal income tax purposes.

Amounts related to the involuntary conversion are as follows at December 31, 2004:

(in thousands)		
Net book value of assets impaired	$	23,978
Increase in asset retirement obligation related to Main Pass assets		130,000
Loss on involuntary conversion of assets		153,978
Probable insurance claims		(152,978)
Net loss on involuntary conversion of assets	$	1,000

Assets (liabilities) included on the Company's balance sheet at December 31, 2004 consist of the following:

(in thousands)		
Probable insurance claims - current	$	65,000
Insurance recoveries received		3,146
Other assets (long-term portion of probable insurance claims)		84,832
Total expected insurance recoveries	$	152,978
Asset retirement obligation - current	$	(65,000)
Asset retirement obligation - long-term		(65,000)
Total increase in asset retirement obligation related to Main Pass assets	$	(130,000)

Note 4 - Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair values, which were obtained from third parties, for 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, Cash Equivalents, Accounts Receivable and Accounts Payable

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

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:

	2004		2003	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 880,256	$ 963,319	$ 776,021	$ 836,271

Note 5 - Capitalized Exploratory Well Costs

The Company capitalizes exploratory well costs until a determination is made that the well has found proved reserves or that it is impaired, in which case the well costs are charged to expense. The following table reflects the Company's capitalized exploratory well activity during each of the years ended December 31:

	Year Ended December 31,		
(dollars in thousands)	2004	2003	2002
Capitalized exploratory well costs at beginning of period	$ 29,375	$ 30,237	$ 36,341
Additions to capitalized exploratory well costs pending the determination of proved reserves	45,011	29,092	11,409
Reclassified to property, plant and equipment based on the determination of proved reserves	(1,061)	(4,377)	(1,438)
Capitalized exploratory well costs charged to expense	(10,601)	(25,577)	(16,075)
Capitalized exploratory well costs at end of period	$ 62,724	$ 29,375	$ 30,237

The following table provides an aging of capitalized exploratory well costs (suspended well costs) based on the date the drilling was completed and the number of wells for which exploratory well costs have been capitalized for a period greater than one year since the drilling was completed:

	Year Ended December 31,		
(dollars in thousands)	**2004**	**2003**	**2002**
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ 44,986	$ 27,681	$ 4,152
Capitalized exploratory well costs that have been capitalized for a period greater than one year	17,738	1,694	26,085
Balance at end of the period	$ 62,724	$ 29,375	$ 30,237
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	4	4	3

Included in the total suspended well costs at year-end 2004 was $50.0 million related to two deepwater Gulf of Mexico projects. One of the projects, Lorien, which includes $44.7 million, was discovered in 2003 and encountered 120 feet of net pay, primarily crude oil. The Company increased its working interest from 20 percent to 60 percent in the second quarter of 2004. A successful appraisal sidetrack well was drilled in 2004 and a second appraisal well is being drilled in the first quarter of 2005 to delineate the reservoir. Reserves are expected to be recorded in 2005, at which time the suspended well costs will be reclassified to property, plant and equipment. In addition, there is $4.1 million related to two projects in the North Sea, one of which is expected to lead to development during 2005. The remaining $8.6 million related to activities that are ongoing and being pursued.

Included in the total suspended well costs at year-end 2003 was $15.9 million related to Lorien and $7.7 million related to three Gulf of Mexico projects that were under evaluation at year-end and subsequently determined to be noncommercial and impaired in 2004. In the North Sea, there was $1.8 million related to three projects that were under evaluation at year-end 2003 and subsequently determined to be noncommercial and impaired in 2004. There was $1.0 million related to two domestic onshore projects that were under evaluation at year-end 2003 and subsequently determined to be noncommercial and impaired in 2004. The remaining $2.9 million related to activities that were ongoing and being pursued.

Included in the total suspended well costs at year-end 2002 was $13.3 million related to exploration efforts in the Nam Con Son Basin of Vietnam. In July 2001, the 12W-TN-1X well tested natural gas of 20 MMcfpd and 150 Bpd of condensate. During the remainder of 2002 and 2003, various exploration efforts, including seismic and additional drilling, were undertaken. After these evaluations were completed, the Company elected not to pursue any additional exploration efforts in Vietnam and wrote off its investment in 2003. Offshore China, there was $11.3 million related to block 16/02 that originally tested crude oil and natural gas in 2001. During 2002, the operator undertook various exploration and evaluation efforts, but the block was subsequently determined to be noncommercial and impaired in 2003. In the North Sea, there was $2.0 million related to a project that was under development and proved reserves were later recorded. The remaining $3.6 million related primarily to domestic onshore projects, of which $2.4 million was later reclassified to property, plant and equipment and $1.2 million was subsequently determined to be noncommercial and impaired.

The Company’s assessment of suspended well costs is continuous until a determination is made that the well has found proved reserves or is noncommercial and is impaired.

Note 6 - Asset Retirement Obligations

The Company adopted SFAS No. 143 on January 1, 2003. SFAS No. 143 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's asset retirement obligations consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with its oil and gas properties. Upon adoption at January 1, 2003, the Company recognized as the fair value of asset retirement obligations, $99.8 million related to the United States and $10.0 million related to the North Sea. The Company also recognized a non-cash pre-tax charge of $9.0 million ($5.8 million, net of tax) as the cumulative effect of a change in accounting principle upon adoption.

Below is a reconciliation of the beginning and ending aggregate carrying amount of the Company's asset retirement obligations:

	Year Ended December 31,	
(dollars in thousands)	**2004**	**2003**
Asset retirement obligation at beginning of period	$ 102,827	$
Initial adoption entry		109,821
Liabilities incurred as a result of Hurricane Ivan	130,000	
Other liabilities incurred in the current period	13,016	2,556
Liabilities settled in the current period	(19,370)	(13,295)
Revisions	19,158	(5,586)
Accretion expense	9,352	9,331
Asset retirement obligation at end of period	$ 254,983	$ 102,827

Revisions to the Company's previously recorded asset retirement obligations during 2004 resulted from changes in the assumptions used to estimate the timing and amounts of the cash flows required to settle asset retirement obligations. Asset retirements incurred in 2004 for the United States include $130.0 million, which will be reimbursed by insurance, related to Hurricane Ivan damage in the Gulf of Mexico. The Company believes it has insurance coverage in an amount sufficient to make necessary repairs in order to re-establish production as a result of Hurricane Ivan. For more information, see "Note 3 - Involuntary Conversion of Assets" of this Form 10-K.

The following table summarizes the pro forma net income and earnings per share, for the year ended December 31, 2002, for SFAS No. 143 had it been implemented on January 1, 2002 (in thousands, except per share amounts):

	As Reported	**Pro Forma**
Net income	$ 17,652	$ 8,556
Net income per share, basic	$ .31	$ .15
Net income per share, diluted	$ .31	$ .15

In addition, if the Company had applied the provisions of SFAS No. 143 as of January 1, 2002, the pro forma amount of the asset retirement obligations would have been $99.7 million.

Note 7 – Debt

A summary of debt at December 31 follows:

(in thousands)	2004 Debt	2004 Percentage Interest Rate	2003 Debt	2003 Percentage Interest Rate
$400 million Credit Agreement, due October 2009	$ 85,000	2.86	$	
$400 million Credit Agreement, due November 2006			140,000	2.19
$300 million Credit Agreement, due October 2005			190,000	2.09
5 1/4% Senior Notes, due 2014	200,000	5.25		
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
Term Loans, due January 2009	150,000	3.00		
AMCCO Series A-2 Notes, due December 2004			125,000	8.95
Israel Note, due January 2004			20,746	2.16
Note obtained in an acquisition, due May 2004			7,928	6.25
Outstanding debt	885,000		933,674	
Less: unamortized discount	4,744		3,979	
current installments of long-term debt			153,674	
Long-term debt	$ 880,256		$ 776,021	

The Company's total long-term debt, net of unamortized discount, at December 31, 2004, was $880.3 million compared to $776.0 million at December 31, 2003. The ratio of debt-to-book capital (defined as the Company's total debt divided by the sum of total debt plus equity) was 38 percent at December 31, 2004, compared with 46 percent at December 31, 2003.

All of the Company's long-term debt is senior unsecured debt and is, therefore, pari passu with respect to the payment of both principal and interest. The indenture documents of each of the 7 1/4% Notes, the 8% Senior Notes and the 7 1/4% Senior Debentures provide that the Company may prepay the instruments by creating a defeasance trust. The defeasance provisions require that the trust be funded by the Company with securities sufficient, in the opinion of a nationally recognized accounting firm, to pay all scheduled principal and interest due under the respective agreements. Interest on each of these issues is payable semi-annually.

Debt Issuances

During October 2004, the Company entered into a new $400 million five-year credit agreement due October 2009. The new agreement is with certain commercial lending institutions and bears facility fees of 10 to 25 basis points per annum and interest rates based upon a Eurodollar rate plus a range of 30 to 112.5 basis points per annum depending upon the percentage of utilization and the Company's credit rating. Interest is payable periodically based on the tenor of the underlying Eurodollar rate selected at the time of drawing. Principal is payable at maturity, but may be prepaid at any time without penalty. This new agreement replaced the $300 million 364-day credit agreement that was terminated in October 2004. The 364-day credit agreement bore interest based upon a Eurodollar rate plus a range of 62.5 to 150 basis points depending upon the percentage of utilization and credit rating.

The Company's $400 million five-year credit agreement due November 2006 is with certain commercial lending institutions and bears facility fees of 15 to 30 basis points per annum and interest rates based upon a Eurodollar rate plus a range of 60 to 145 basis points per annum depending upon the percentage of utilization and the Company's credit rating. Interest is payable periodically based on the tenor of the underlying Eurodollar rate selected at the time of drawing. Principal is payable at maturity, but may be prepaid at any time without penalty.

During first quarter 2004, a subsidiary of the Company, Noble Energy Mediterranean Ltd., entered into term loan agreements with several commercial lending institutions for a total of $150 million. The interest rates on the borrowings are based upon a Eurodollar rate plus an effective range of 60 to 130 basis points depending upon the Company's credit rating. Interest is payable periodically based on the tenor of the underlying Eurodollar rate selected at the time of drawing. The Term Loans expire in January 2009. Proceeds were used to reduce amounts outstanding under the credit agreements.

Financial covenants on each of the $400 million credit facilities include the following: (a) the Company's ratio of EBITDAX to 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 Company's total debt to capitalization ratio, expressed as a percentage, may not exceed 60 percent at any time; and (c) the Company may not incur any guaranteed liabilities in respect of any funded indebtedness of any unrestricted subsidiary in excess of $700 million in the aggregate for all such guaranteed liabilities.

During April 2004, the Company closed an offering of $200 million senior unsecured notes receiving net proceeds of approximately $197.7 million, after deducting underwriting discounts and expenses. The notes mature April 15, 2014 and pay interest semi-annually at 5.25 percent. The net proceeds from the offering were used to repay amounts outstanding under the credit agreements and for general corporate purposes. The Company may redeem these notes at any time, provided it pays all principal and a "make-whole" premium based on the coupon rate and the remaining term of the notes. This redemption option is considered clearly and closely related to the underlying notes and, therefore, is not required to be accounted for separately under SFAS No. 133. The Company had entered into an interest rate lock to protect against a rise in interest rates prior to the issuance of the debt. At the time of the debt offering, the fair market value of the interest rate lock was a payable of $7.6 million. The amount of deferred loss included in accumulated other comprehensive loss was $4.6 million, net of tax, at December 31, 2004. This amount is being reclassified into earnings as adjustments to interest expense over the term of the unsecured notes.

The Company's credit agreements are supplemented by short-term borrowings under various uncommitted credit lines used for working capital purposes. The uncommitted credit lines may be offered by certain banks from time to time at rates negotiated at the time of borrowing. There were no amounts outstanding under these uncommitted credit lines at December 31, 2004 or 2003.

In connection with the proposed merger with Patina, the Company has received a $1.3 billion commitment from certain financial institutions. The new facility will be a reducing revolver due 2010 with a five percent per quarter commitment reduction in each calendar quarter during year four and 20 percent per quarter reduction in year five. The facility will incur a 7.5 basis point "ticking" fee from April 29, 2005 until the effective date of the facility. When the facility becomes effective, the Company will incur a facility fee of 10 to 25 basis points per annum depending upon the Company's credit rating. The facility is to bear interest based upon a Eurodollar rate plus 30 to 100 basis points depending upon the Company's credit rating. Financial covenants on the new facility are similar to those for the Company's currently outstanding debt. In addition, the commitment will be reduced by the net proceeds from certain issuances of debt by the Company and by the amount of proceeds from certain asset sales in excess of $100 million received by the Company.

Debt Repayments

In August 2004, the Company repaid the $125 million AMCCO Series A-2 Notes due December 2004. In connection with the repayment, the Company recognized a loss of $2.9 million ($1.9 million after tax), which is included in interest expense on the Company's consolidated statements of operations. The repayment of the Notes was funded with borrowings under the Company's credit facility. During first quarter 2004, the Company repaid $7.9 million on an acquisition note and $20.7 million of Israel debt.

The Company's annual maturities of outstanding debt are $235.0 million in 2009 and $650.0 million thereafter for a total of $885.0 million of outstanding debt. There are no scheduled maturities of the Company's outstanding debt prior to 2009.

Note 8 - 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)	2004	2003	2002
Federal statutory rate	35.0	35.0	35.0
Effect of:			
State taxes, net of federal benefit	0.7	0.4	1.1
Difference between U.S. and foreign rates	5.6	14.6	36.8
Write-off of Vietnam investment		(11.5)	
Release of China valuation allowance	(2.7)		
Other, net	0.6	(2.0)	(2.0)
Effective rate	39.2	36.5	70.9

The net current deferred tax asset in the following table is classified as other current assets on 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)	2004	2003
U.S. and State Current Deferred Tax Assets (Liabilities):		
Accrued expenses	$ 1,453	$ 1,507
Deferred income	271	351
Allowance for doubtful accounts	2,115	2,184
Fair value of derivative contracts	8,180	4,102
Postretirement benefits	1,650	
Other	(630)	(643)
Net U.S. and State Current Deferred Tax Assets (Liabilities)	13,039	7,501
U.S. and State Noncurrent Deferred Tax Assets (Liabilities):		
Property, plant and equipment, principally due to differences in depreciation, amortization, lease impairment and abandonments	(145,585)	(140,760)
Accrued expenses	6,393	4,777
Deferred income	3,088	2,848
Allowance for doubtful accounts	6,643	5,935
Foreign and state income tax accruals	12,991	8,716
Postretirement benefits	7,158	8,169
Fair value of derivative contracts	(3,611)	
Reclass to income taxes – current	6,570	
Other	(1,753)	(235)
Net U.S. and State Noncurrent Deferred Tax Assets (Liabilities)	(108,106)	(110,550)
Total Net U.S. and State Deferred Tax Assets (Liabilities)	(95,067)	(103,049)
Foreign Noncurrent Deferred Tax Assets (Liabilities):		
Property, plant and equipment of foreign operations	(97,789)	(54,809)
Foreign loss carryforward	22,350	16,732
Net Foreign Noncurrent Deferred Tax Assets (Liabilities)	(75,439)	(38,077)
Valuation allowance		(14,519)
Other foreign	194	
Total Net Deferred Tax Assets (Liabilities)	$ (170,312)	$ (155,645)

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

(in thousands)	2004	2003	2002
Domestic	$ 254,582	$ 56,068	$ (11,636)
Foreign	261,459	85,571	39,532
Total	$ 516,041	$ 141,639	$ 27,896

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

(in thousands)	2004	2003	2002
U.S. current	$ 136,858	$ 45,985	$ (7,945)
U.S. deferred	1,192	(31,087)	1,421
State current	6,930	1,867	895
State deferred	(702)	(1,084)	(212)
Foreign current	40,955	32,341	14,675
Foreign deferred	24,960	461	16,113
Provision including discontinued operations	210,193	48,483	24,947
Income tax provision associated with discontinued operations	8,002	(3,264)	5,146
Total income tax provision	$ 202,191	$ 51,747	$ 19,801

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 at December 31, 2004. 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.

The Company has recognized deferred tax assets associated with its foreign loss carryforwards. The tax effect of these carryforwards increased from $16.7 million in 2003 to $22.3 million in 2004, all of which related to China. The valuation allowances associated with those carryforwards decreased from $14.5 million in 2003 to zero in 2004. Under Chinese tax law, the Company may carryforward its operating losses for five years. The 2003 loss of $26.7 million will expire in 2009 if it cannot be utilized. Due to the positive results of recent drilling activities and projections of future taxable income, management believes it is more likely than not that the deferred tax assets related to certain foreign loss carryforwards will be realized.

The Company has not recorded U.S. deferred income taxes on the undistributed earnings of its consolidated foreign subsidiaries as of December 31, 2004. The Company has begun an evaluation of the effects of the repatriation provision of the AJCA (see “Impact of Recently Issued Accounting Pronouncements” of this Form 10-K). Until the Company decides to repatriate any foreign earnings, it will continue to treat them as permanently invested. As of December 31, 2004, the accumulated undistributed earnings of the consolidated foreign subsidiaries were approximately $189.9 million. Upon distribution of these earnings in the form of dividends or otherwise, the Company may be subject to U.S. income taxes and foreign withholding taxes. It is not practicable, however, to estimate the amount of taxes that may be payable on the eventual remittance of these earnings because of the possible application of U.S. foreign tax credits. Presently the Company is not claiming foreign tax credits, but it may be in a credit position when any future remittance of foreign earnings takes place.

Note 9 - Stock Options, Restricted Stock and Stockholder Rights

Stock Options and Restricted Stock – 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. 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 percent 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 and again in 2003, 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 9,250,000 shares. At December 31, 2004, the Company had reserved 5,183,881 shares of common stock for issuance, including 2,986,234 shares available for grant, under its 1992 Plan.

During 2004, the Board of Directors approved a change in the form of incentive awards to be granted to officers and key employees of the Company. The change results in the granting of restricted shares and performance units, with fewer stock options being granted. The change was a result of a desire to more closely align the Company's long-term incentive plans with its operating and market performance and was based on the advice of a third-party compensation consultant. During the year ended December 31, 2004, the Board of Directors granted 42,295 restricted shares of Company common stock to officers and key employees of the Company. The restricted shares are subject to a restricted period ending February 1, 2007 and are also subject to the achievement of a performance goal as of December 31, 2006. When restricted stock is granted, unearned compensation related to the restricted shares is charged to deferred compensation. Compensation expense is recognized over the balance of the vesting period and is adjusted if conditions of the restricted stock performance goal are not met. Amounts related to the performance-based restricted stock awards are subsequently adjusted for changes in the market value of the underlying stock. For the year ended December 31, 2004, the Company's compensation expense included $.6 million, net of tax, related to the restricted stock awards. During 2004, 1,104 restricted shares were forfeited and 41,191 restricted shares remained outstanding at December 31, 2004. No restricted stock awards were granted during the years ended December 31, 2003 or 2002.

The Company has a 2004 Long-Term Incentive Plan ("LTIP"). Under the LTIP, awards may be made by the Board of Directors in the form of stock options or restricted stock granted or awarded under the 1992 Plan, or in the form of performance units or other incentive measurements providing for the payment of bonuses in cash, or in any combination thereof, as determined by the Board of Directors in its discretion. For the year ended December 31, 2004, the Company's compensation expense included $1.2 million related to the performance units.

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 was amended in 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 calendar 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. The 1988 Plan was amended again in 2004, by a vote of the shareholders, to increase the maximum number of shares of common stock that may be issued under the 1988 Plan to 750,000 shares. At December 31, 2004, the Company had reserved 446,571 shares of common stock for issuance, including 239,786 shares available for grant, under its 1988 Plan.

A summary of the status of Noble Energy's stock option plans as of December 31, 2002, 2003 and 2004, 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, 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	(36,612)	$ 37.02		
Outstanding at December 31, 2002	**4,193,221**	**$ 33.38**	**2,871,943**	**$ 32.84**
Options granted	758,900	$ 35.42		
Options exercised	(876,516)	$ 28.16		
Options canceled	(106,561)	$ 36.96		
Outstanding at December 31, 2003	**3,969,044**	**$ 34.83**	**2,642,077**	**$ 34.40**
Options granted	325,035	$ 44.44		
Options exercised	(1,786,643)	$ 35.03		
Options canceled	(124,195)	$ 35.71		
Outstanding at December 31, 2004	**2,383,241**	**$ 35.31**	**1,492,825**	**$ 34.76**

The following table summarizes information about Noble Energy's stock options, which were outstanding, and those that were exercisable, as of December 31, 2004.

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$17.79 - $22.23	208,984	4.2 Years	$ 20.06	208,984	$ 20.06
$22.23 - $26.68	32,172	0.5 Years	$ 24.58	32,172	$ 24.58
$26.68 - $31.13	68,789	4.7 Years	$ 29.56	68,789	$ 29.56
$31.13 - $35.57	972,874	7.5 Years	$ 34.17	385,479	$ 33.64
$35.57 - $40.02	444,062	3.6 Years	$ 37.79	444,062	$ 37.79
$40.02 - $44.47	656,360	7.2 Years	$ 43.53	353,339	$ 42.78
	2,383,241	6.3 Years	$ 35.31	1,492,825	$ 34.76

The Company's income tax benefit associated with the exercise of stock options was $9.7 million, $3.9 million and $2.0 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Stockholder Rights 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 per share. 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.

Note 10 – Other Comprehensive Income

The components of other comprehensive income (loss) ("OCI") are as follows:

(dollars in thousands)	Year Ended December 31, 2004	2003	2002
Other comprehensive income (loss), net of tax:			
Unrealized gain (loss) on cash flow hedges:			
Unrealized fair value gain (loss) during period:			
Oil and gas cash flow hedges (1)	$ (39,161)	$ (36,824)	$ (15,878)
Interest rate lock cash flow hedge (2)	(2,417)	(2,509)	
Less: reclassification adjustment for amounts out of OCI:			
Oil and gas cash flow hedges (3)	39,840	43,843	(3,829)
Interest rate lock cash flow hedge (4)	348		
Change in additional minimum pension liability and other	(2,511)	(793)	34
Other comprehensive income (loss)	$ (3,901)	$ 3,717	$ (19,673)

		2004	2003	2002
(1)	Income tax (benefit):	$ (21,087)	$ (19,828)	$ (8,550)
(2)	Income tax (benefit):	(1,301)	(1,351)	
(3)	Income tax provision (benefit):	21,452	23,608	(2,062)
(4)	Income tax provision:	187		

Accumulated other comprehensive loss in the equity section of the balance sheet included:

(dollars in thousands)	2004	2003
Deferred net loss on oil and gas cash flow hedges	$ (6,939)	$ (7,618)
Deferred net loss on interest rate cash flow hedge	(4,577)	(2,509)
Minimum pension liability and other	(3,271)	(759)
Accumulated other comprehensive income	$ (14,787)	$ (10,886)

Note 11 - 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, which provides for restoration of amounts to 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.

The Company sponsors other plans for the benefit of its employees and retirees. These plans include health care and life insurance benefits. The Company uses a December 31 measurement date for its plans. The following table reflects the change in benefit obligation and change in plan assets of the Company's pension and other postretirement benefit plans at December 31:

	Pension Benefits		Other Benefits	
(in thousands)	2004	2003	2004	2003
Change in benefit obligation				
Benefit obligation at beginning of year	$ 118,270	$ 106,224	$ 9,156	$ 6,141
Service cost	6,248	5,271	610	534
Interest cost	7,303	6,772	577	524
Amendments	470	196	(1,036)	
Plan participants' contributions			177	114
Actuarial loss	5,536	4,366	2,809	2,053
Benefits paid	(5,081)	(4,559)	(578)	(210)
Benefit obligation at year-end	$ 132,746	$ 118,270	$ 11,715	$ 9,156
Change in plan assets				
Fair value of plan assets at beginning of year	$ 74,025	$ 56,660	$	$
Actual return on plan assets	7,919	7,583		
Employer contribution	4,252	14,341	578	210
Benefits paid	(5,081)	(4,559)	(578)	(210)
Fair value of plan assets at end of year	$ 81,115	$ 74,025	$	$
Funded status	$ (51,631)	$ (44,245)	$ (11,715)	$ (9,156)
Unrecognized net actuarial loss	29,650	25,849	7,401	4,955
Unrecognized prior service cost (benefit)	2,518	2,402	(1,636)	(836)
Unrecognized net transition obligation	1,118	1,142		
Accrued benefit costs	$ (18,345)	$ (14,852)	$ (5,950)	$ (5,037)

The following table reflects the costs recognized for the Company's pension and other postretirement benefits plans:

	Pension Benefits			Other Benefits		
(in thousands)	2004	2003	2002	2004	2003	2002
Components of net periodic benefit cost						
Service cost	$ 6,248	$ 5,271	$ 4,986	$ 610	$ 534	$ 346
Interest cost	7,303	6,772	7,071	577	524	314
Expected return on plan assets	(6,745)	(5,857)	(5,474)			
Transition obligation recognition	25	24	24			
Amortization of prior service cost	353	319	306	(236)	(110)	(30)
Recognized net actuarial loss	560	158	845	363	272	73
Net periodic benefit cost	$ 7,744	$ 6,687	$ 7,758	$ 1,314	$ 1,220	$ 703
Additional Information						
Increase in minimum liability included in accumulated other comprehensive income	$ 4,716	$ 1,594				
Weighted-average assumptions used to determine benefit obligations at December 31,						
Discount rate	6.00%	6.25%	6.75%	5.75%	6.25%	6.75%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Weighted-average assumptions used to determine net periodic benefit costs for year ended December 31,						
Discount rate	6.25%	6.75%	7.25%	6.25%	6.75%	7.25%
Expected long-term return on plan assets	8.50%	8.50%	8.50%			
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%

Amounts recognized in the statement of financial position consist of:

(in thousands)	Pension Benefits 2004	Pension Benefits 2003	Other Benefits 2004	Other Benefits 2003
Accrued benefit cost	$ (18,345)	$ (14,852)	$ (5,950)	$ (5,037)
Intangible assets	3,851	3,974		
Accumulated other comprehensive income, net of tax	3,065	1,036		
Net amount recognized	$ (11,429)	$ (9,842)	$ (5,950)	$ (5,037)

In selecting the assumption for expected long-term rate of return on assets, Noble Energy considers the average rate of earnings expected on the funds to be invested to provide for plan benefits. This includes considering the trusts' asset allocation, historical returns on these types of assets, the current economic environment and the expected returns likely to be earned over the life of the plan. The Company assumes its long-term asset mix will be consistent with its target asset allocation of 70 percent equity and 30 percent fixed income, with a range of plus or minus 10 percent acceptable degree of variation in the plan's asset allocation. Based on these factors, the Company expects its pension assets will earn an average of 8.5 percent per annum over the life of the plan. This basis is consistent with the prior year.

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:

(in thousands)	Defined Benefit Pension Plan 2004	Defined Benefit Pension Plan 2003	Restoration Benefit Plan 2004	Restoration Benefit Plan 2003
Aggregated pension benefits				
Aggregate fair value of plan assets	$ 81,115	$ 74,025	$	$
Aggregate accumulated benefit obligation	(92,611)	(80,738)	(15,416)	(13,708)
Funded status of net periodic benefit obligation	$ (11,496)	$ (6,713)	$ (15,416)	$ (13,708)

Medical trend rates were 10 percent for 2004, grading down to five percent in years 2008 and later. 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	$ 1,353	$ 1,045
Total postretirement benefit obligation	$ 13,160	$ 10,461

The following table reflects weighted-average asset allocations by asset category for the Company's pension benefit plans at December 31:

	Target Allocation 2005	Plan Assets 2004	Plan Assets 2003
Asset category			
Equity securities	70%	71.6%	70.75%
Fixed income	30%	28.4%	28.97%
Other%	%	%	0.28%
Total	100%	100.00%	100.00%

The investment policy for the defined benefit pension plan is determined by the Company's employee benefits committee ("the committee") with input from a third-party investment consultant. Based on a review of historical rates of return achieved by equity and fixed income investments in various combinations over multi-year holding periods and an evaluation of the probabilities of achieving acceptable real rates of return, the committee has determined the target asset allocation deemed most appropriate to meet the immediate and future benefit payment requirements for the plan and to provide a diversification strategy which reduces market and interest rate risk. A one percent decrease in the expected return on plan assets would have resulted in an increase in benefit expense of $.8 million in 2004.

Noble Energy bases its determination of the asset return component of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2004, the Company had cumulative asset losses of approximately $2.2 million, which remain to be recognized in the calculation of the market-related value of assets.

Plan assets include $58.1 million of equity securities and $23.0 million of fixed income securities.

Contributions

The Company contributed cash of $4.3 million to its pension plans during 2004. The Company expects to make additional cash contributions of $12.3 million relating to the 2004 plan year during 2005 (unaudited).

Estimated Future Benefit Payments

As of December 31, 2004, the following future benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

(in thousands)	Pension Benefits	Other Benefits
2005	$ 5,779	$ 441
2006	$ 5,935	$ 552
2007	$ 6,156	$ 627
2008	$ 6,410	$ 707
2009	$ 6,678	$ 807
Years 2010 to 2014	$ 42,027	$ 5,252

The estimate of expected future benefit payments is based on the same assumptions used to measure the Company’s benefit obligation at December 31, 2004 and includes estimated future employee service.

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)	2004	2003	2002
Employers’ plan contribution	$ 2,350	$ 2,412	$ 2,302

Note 12 - Derivative Instruments and Hedging Activities

Cash Flow Hedges – The Company uses various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations. Such instruments include fixed price contracts, variable to fixed price swaps, costless collars and other contractual arrangements. Although these derivative instruments expose the Company to credit risk, the Company takes reasonable steps to protect itself from nonperformance by its counterparties and periodically assesses necessary provisions for bad debt allowance. However, the Company is not able to predict sudden changes in its counterparties' creditworthiness.

The Company accounts for its derivative instruments under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, and has elected to designate its derivative instruments as cash flow hedges. Both at the inception of a hedge and on an ongoing basis, a cash flow hedge must be expected to be highly effective in achieving offsetting cash flows attributable to the hedged risk during the term of the hedge. Derivative instruments designated as cash flow hedges are reflected at fair value as either assets or liabilities on the Company's consolidated balance sheets. Changes in fair value, to the extent the hedge is effective, are reported in AOCI until the forecasted transaction occurs. Gains and losses from such derivative instruments related to the Company's crude oil and natural gas production and which qualify for hedge accounting treatment are recorded in oil and gas sales and royalties on the Company's consolidated statements of operations upon sale of the associated products. Hedge effectiveness is assessed at least quarterly based on total changes in the derivative's fair value. Any ineffective portion of the derivative instrument's change in fair value is recognized immediately in other expense/(income), net.

During 2004, 2003 and 2002, the Company entered into various crude oil and natural gas fixed price swaps and costless collars related to its crude oil and natural gas production. The tables below summarize the various transactions.

Natural Gas	2004	2003	2002
Hedge MMBTUpd	120,284	190,038	170,274
Floor price range	\$3.75 - \$5.00	\$3.25 - \$3.80	\$2.00 - \$3.50
Ceiling price range	\$5.16 - \$9.65	\$4.00 - \$5.25	\$2.45 - \$5.10
Percent of daily production	33%	56%	50%

Crude Oil	2004	2003	2002
Hedge Bpd	16,261	15,793	5,247
Floor price range	\$24.00 - \$37.50	\$23.00 - \$27.00	\$23.00 - \$24.00
Ceiling price range	\$30.00 - \$54.00	\$27.20 - \$35.05	\$29.30 - \$30.10
Percent of daily production	36%	44%	18%

During 2004, 2003 and 2002, no gains or losses were reclassified into earnings as a result of the discontinuance of hedge accounting treatment. During 2004, 2003 and 2002, the Company's ineffectiveness related to its cash flow hedges was de minimis.

As of December 31, 2004, the Company had entered into costless collars related to its natural gas and crude oil production as follows:

Natural Gas				Crude Oil			
		Average Price Per MMBTU				Average Price Per Bbl	
Production Period	MMBTUpd	Floor	Ceiling	Production Period	Bopd	Floor	Ceiling
2005	79,932	\$ 5.07	\$ 7.82	2005	20,519	\$ 31.56	\$ 43.71
2006	3,699	\$ 5.00	\$ 8.00	2006	1,865	\$ 29.00	\$ 34.93

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 scheduled 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 scheduled trading day applicable for each calculation period is more than the ceiling price. The amount payable by the Company, 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 counterparty, 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.

As of December 31, 2004, the Company had entered into fixed price swaps related to its natural gas and crude oil production as follows:

Natural Gas			Crude Oil		
Production Period	MMBTUpd	Average Price Per MMBTU	Production Period	Bopd	Average Price Per Bbl
2005	53,699	$ 6.63	2005	6,443	$ 39.24
2006	130,000	$ 6.39	2006	10,600	$ 39.98
2007	130,000	$ 5.95	2007	11,100	$ 39.02
2008	130,000	$ 5.59	2008	10,500	$ 38.16

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 scheduled trading day applicable for each calculation period is less than the fixed price. The Company would pay the counterparty if the settlement price for the scheduled trading day applicable for each calculation period is more than the fixed price. The amount payable by the Company, if the floating price is above the fixed price, is the product of the notional quantity per calculation period and the excess, if any, of the floating price over the fixed price in respect of each calculation period. The amount payable by the counterparty, if the floating price is below the fixed price, is the product of the notional quantity per calculation period and the excess, if any, of the fixed price over the floating price in respect of each calculation period.

Accumulated Other Comprehensive Income/(Loss) – As of December 31, 2004 and 2003, the balance in AOCI included net deferred losses of $6.9 million and $7.6 million, respectively, related to the fair value of crude oil and natural gas derivative instruments accounted for as cash flow hedges. The net deferred losses are net of deferred income tax benefit of $3.7 million and $4.1 million, respectively.

If commodity prices were to stay the same as they were at December 31, 2004, approximately $22.3 million of deferred losses related to the fair values of crude oil and natural gas derivative instruments included in AOCI at December 31, 2004 would be reclassified to earnings during the next twelve months as the forecasted transactions occur, and would be recorded as a reduction in oil and gas sales and royalties. Any actual increase or decrease in revenues will depend upon market conditions over the period during which the forecasted transactions occur. All current crude oil and natural gas derivative instruments, except those described in the following paragraph, are designated as cash flow hedges.

Other Derivative Instruments – In addition to the derivative instruments pertaining to the Company's production as described above, NEMI, from time to time, employs various derivative instruments in connection with its purchases and sales of third-party production to lock in profits or limit exposure to natural 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 instrument to convert the fixed or NYMEX sale to an index basis thereby determining the margin and minimizing the risk of price volatility.

Derivative instruments used by NEMI in connection with its purchases and sales of third-party production are reflected at fair value as either assets or liabilities on the Company's consolidated balance sheets. NEMI records gains and losses on derivative instruments using mark-to-market accounting. Under this accounting method, the changes in the market value of outstanding derivative instruments are recognized as gains or losses in the period of change. Gains and losses related to changes in fair value are included in gathering, marketing and processing revenues on the Company's statements of operations. NEMI recorded a gain of less than $.1 million, a loss of $.2 million and a gain of $.9 million in GMP proceeds during 2004, 2003 and 2002, respectively, related to derivative instruments.

Receivables/Payables Related to Crude Oil and Natural Gas Derivative Instruments – At December 31, 2004, the Company's consolidated balance sheet included a receivable of $49.2 million (of which $28.7 million is current) and a payable of $60.0 million (of which $50.3 million is current) related to crude oil and natural gas derivative instruments. At December 31, 2003, the Company's consolidated balance sheet included a receivable of $56.1 million (of which $48.1 million is current) and a payable of $67.2 million (of which $59.8 million is current) related to crude oil and natural gas derivative instruments.

Interest Rate Lock – The Company occasionally enters into forward contracts or swap agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate swaps or interest rate "locks" used as cash flow hedges are reported in AOCI, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense over the term of the related notes. During 2003, the Company had entered into an interest rate lock to protect against a rise in interest rates prior to the issuance of its $200 million senior unsecured notes. At the time of the debt issuance in April 2004, the fair market value of the interest rate lock was a payable of $7.6 million. The amount of deferred loss included in AOCI was $4.6 million, net of tax, at December 31, 2004. This amount is being reclassified into earnings as adjustments to interest expense over the term of the unsecured notes ($.5 million for the year ending December 31, 2004). At December 31, 2003, the amount of deferred loss included in AOCI was $2.5 million, net of tax.

Note 13 - Unconsolidated Subsidiaries

Through its ownership interest in AMCCO, the Company owns a 45 percent interest in AMPCO, which completed construction of a methanol plant in Equatorial Guinea in the second quarter of 2001. The plant construction started during 1998 and initial production of commercial grade methanol commenced May 2, 2001. 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 of natural gas from the Alba field. The methanol plant has a contract, which runs through 2026, to purchase natural gas from the Alba field. The Company's investment in the methanol plant is included in investment in unconsolidated subsidiaries on the Company's balance sheets, and the Company's share of earnings is reported as income from unconsolidated subsidiaries on the Company's statements of operations.

AMCCO, AMPCO, AMPCO Marketing LLC, AMPCO Services LLC and Samedan Methanol are accounted for using the equity method. The Company owns a 45 percent interest in AMPCO and a 50 percent interest in each of the remaining unconsolidated subsidiaries.

The following are the summarized balance sheets at December 31 and the statements of operations for the years ended December 31 for subsidiaries accounted for using the equity method:

Consolidated Balance Sheets
Equity Method Subsidiaries

(in thousands)	2004	2003
Assets		
Current assets	$ 134,596	$ 73,604
Noncurrent assets - net of depreciation	388,982	397,084
Total Assets	$ 523,578	$ 470,688
Liabilities and Members' Equity		
Current liabilities	$ 80,310	$ 39,855
Members' equity	443,268	430,833
Total Liabilities and Members' Equity	$ 523,578	$ 470,688

Consolidated Statements of Operations
Equity Method Subsidiaries

(in thousands)	2004	2003	2002
Revenue			
Methanol sales	$ 225,606	$ 171,126	$ 97,476
Other income	28,499	17,232	18,471
Total Revenue	254,105	188,358	115,947
Less cost of goods sold	95,119	76,244	71,687
Gross Margin	158,986	112,114	44,260
Expenses			
DD&A	19,471	20,018	20,763
Administrative	3,887	3,691	3,076
Total Expenses	23,358	23,709	23,839
Deferred tax benefit	16,495		
Net Income	$ 152,123	$ 88,405	$ 20,421

The deferred tax benefit of $16.5 million for 2004 represents the reversal of AMPCO's deferred tax asset valuation allowance, plus additional deferred taxes recognized on 2004 income. AMPCO will become liable for income taxes beginning in 2005, upon the conclusion of an income tax holiday.

<u>Note 14 - Commitments and Contingencies</u>

Legal Proceedings – 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.

On October 15, 2002, Noble Gas Marketing, Inc. and Samedan Oil Corporation, 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 ENA, under

Chapter 11 of the U.S. Bankruptcy Code. The proofs of claim relate to certain natural gas sales agreements and aggregate approximately $12 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 at issue.

On January 13, 2003, the Noble Defendants filed an answer to ENA's complaint. On January 29, 2003, the Noble Defendants filed the Motion of Noble Energy Marketing, Inc., as Successor to Noble Gas Marketing, Inc., and Noble Energy, Inc., as Successor to Samedan Oil Corporation, to Compel Arbitration. On March 4, 2003, the Court issued its Order Governing Mediation of Trading Cases and Appointing the Honorable Allan L. Gropper as Mediator (the "Mediation Order") which, among other things, abated this case and referred it to mediation along with other pending adversary proceedings in the Enron bankruptcy cases which involve disputes arising from or in connection with commodity trading contracts. Pursuant to the Mediation Order, the Honorable Allan L. Gropper (United States Bankruptcy Judge for the Southern District of New York) has acted as mediator for this case and the other trading cases which have been referred to him. Mediation sessions for this case were held on December 17, 2003 and May 21, 2004. In January 2005, the parties reached a preliminary settlement of matters in dispute subject to the approval of ENA's internal committees, the board of directors of Enron Corp., and the United States Bankruptcy Court. The proposed settlement, if approved, will not have a material adverse effect on the Company's consolidated financial position, results of operations or liquidity. The Company was adequately reserved for this settlement and there will be no resulting gain or loss.

Note 15 - 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, Equatorial Guinea, North Sea, Israel and Other International, Corporate and Marketing. Other International includes operations in Argentina, China and Ecuador.

The Company's accounting policies for geographical segments are the same as those described in the summary of significant accounting policies. Transfers between segments are accounted for at market value. The Company does not consider interest income and expense or income tax benefit or expense in its evaluation of the performance of geographical segments.

(Dollars in Thousands)

Year Ended December 31, 2004	Consolidated	United States	Equatorial Guinea	North Sea	Israel	Other Int'l, Corporate & Marketing
Revenues from external customers	$ 1,282,076	$ 326,698	$ 143,069	$ 115,181	$ 48,855	$ 648,273
Intersegment revenues		455,068				(455,068)
Income from unconsolidated subsidiaries	69,100		69,100			
Total Revenues	$ 1,351,176	$ 781,766	$ 212,169	$ 115,181	$ 48,855	$ 193,205
DD&A	$ 308,855	$ 240,058	$ 14,677	$ 18,244	$ 9,058	$ 26,818
Accretion on asset retirement obligation	$ 9,352	$ 8,021	$ 6	$ 1,140	$ 163	$ 22
Impairment of operating assets	$ 9,855	$ 9,855	$	$	$	$
Operating income/(loss) from continuing operations	$ 516,041	$ 294,412	$ 165,609	$ 70,305	$ 32,088	$ (46,373)
Investment in unconsolidated subsidiaries	$ 231,795	$	$ 231,795	$	$	$
Additions to long-lived assets	$ 530,943	$ 280,280	$ 175,686	$ 10,795	$ (8,313)	$ 72,495
Total assets	$ 3,443,171	$ 1,299,547	$ 817,062	$ 218,881	$ 273,347	$ 834,334

Year Ended December 31, 2003	Consolidated	United States	Equatorial Guinea	North Sea	Israel	Other Int'l, Corporate & Marketing
Revenues from external customers	$ 965,324	$ 110,106	$ 68,644	$ 100,558	$	$ 686,016
Intersegment revenues		495,261				(495,261)
Income from unconsolidated subsidiaries	40,626		40,626			
Total Revenues	$ 1,005,950	$ 605,367	$ 109,270	$ 100,558	$	$ 190,755
DD&A	$ 309,343	$ 254,041	$ 6,115	$ 28,219	$ 40	$ 20,928
Accretion on asset retirement obligation	$ 9,331	$ 8,449	$	$ 882	$	$
Impairment of operating assets	$ 31,937	$ 31,937	$	$	$	$
Operating income/(loss) from continuing operations	$ 141,639	$ 105,024	$ 86,099	$ 42,373	$ (7,743)	$ (84,114)
Investment in unconsolidated subsidiaries	$ 227,669	$	$ 227,669	$	$	$
Additions to long-lived assets	$ 413,307	$ 110,320	$ 222,315	$ 6,622	$ 66,751	$ 7,299
Total assets	$ 2,842,649	$ 1,037,106	$ 620,663	$ 163,381	$ 267,915	$ 753,584

Year Ended December 31, 2002	Consolidated	United States	Equatorial Guinea	North Sea	Israel	Other Int'l, Corporate & Marketing
Revenues from external customers	$ 691,800	$ 149,480	$ 48,882	$ 91,538	$	$ 401,900
Intersegment revenues		294,465				(294,465)
Income from unconsolidated subsidiaries	9,532		9,532			
Total Revenues	$ 701,332	$ 443,945	$ 58,414	$ 91,538	$	$ 107,435
DD&A	$ 236,881	$ 192,708	$ 5,849	$ 28,279	$ 31	$ 10,014
Operating income/(loss) from continuing operations	$ 27,896	$ 20,493	$ 39,331	$ 37,378	$ (2,674)	$ (66,632)
Investment in unconsolidated subsidiaries	$ 234,668	$	$ 234,668	$	$	$
Additions to long-lived assets	$ 307,179	$ 167,140	$ 51,839	$ 9,769	$ 14,767	$ 63,664
Total assets	$ 2,730,015	$ 1,337,017	$ 406,131	$ 109,868	$ 187,429	$ 689,570

Note 16 - Company Stock Repurchase Forward Program

In accordance with a Board-approved stock repurchase forward program, one of the Company's banks purchased 1,044,454 shares of Company stock on the open market during 2001 and 2002. During the second quarter of 2003, the Company adopted SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity." As a result, the Company recorded an additional 1,044,454 shares of treasury stock at a cost of $36.6 million and an obligation of $36.6 million. In December 2003, the Company paid the obligation in full.

Note 17 - Discontinued Operations

During 2004, the Company completed an asset disposition program that had first been announced during July 2003. The asset disposition program included five domestic property packages. The sales price for the five property packages totaled approximately $130 million before closing adjustments. Pursuant to SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the Company's consolidated financial statements were reclassified for all periods presented to reflect the operations and assets of the properties being sold as discontinued operations. The net income from discontinued operations was classified on the consolidated statements of operations as "Discontinued Operations, Net of Tax."

Summarized results of discontinued operations are as follows:

	Year ended December 31,		
(dollars in thousands)	2004	2003	2002
Oil and gas sales and royalties	$ 12,575	$ 106,339	$ 91,576
Write down to market value and realized (gain)/loss	(14,996)	59,171	
Income (loss) before income taxes	22,862	(9,325)	14,703

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. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Company engineers in the Houston office perform all reserve estimates for the Company's different geographical regions. These reserve estimates are reviewed and approved by corporate engineering staff with final approval by the Senior Vice President of Production and Drilling.

Beginning in 2004, Noble Energy engaged independent third-party reserve engineers to perform a Reserve Audit of proved reserves. The reserve audit for 2004 included a detailed review of the major properties, which covered approximately 78 percent of Noble Energy's total proved reserves. The estimates of the third-party engineers supported the reserves booked by the Company. For the three years prior to 2004, Noble Energy engaged independent third-party reserve engineers to perform a Reserve Procedural Audit of the Company's procedures and methods used to estimate proved reserves.

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.

The following definitions apply to the terms used in the paragraphs above:

<u>Reserve Estimate.</u> The determination of an estimate of a quantity of oil or gas reserves that are thought to exist at a certain date, considering existing prices and reservoir conditions.

<u>Reserve Audit.</u> The process involving an independent third-party engineering firm's extensive visits, collection of any and all required geologic, geophysical, engineering and economic data, and such firm's complete external preparation of reserve estimates.

<u>Reserve Procedural Audit.</u> The process involving an independent third-party engineering firm's overview of the Company's data only, where firm representatives attend Company internal meetings, learn about the methodologies and processes used to ascertain and book proved reserves, and may review selected data. This process does not involve generating an independent third-party estimate of reserve quantities.

SEC guidelines do not limit reserve bookings to only contracted volumes if it can be demonstrated that there is reasonable certainty that a market exists. The Company has booked reserves in excess of contracted volumes for Israel due to the reasonable certainty of the existence of markets in future periods. In Israel, the Company has a natural gas contract with IEC, which is expected to run through 2014, and a contract with the Israel Bazan Refinery through the year 2015. The Israeli natural gas market, as estimated by the Israeli Ministry of National Infrastructure, from 2005 to 2020, is significantly greater than Noble Energy's uncontracted net estimated proved reserves.

The following definitions apply to the Company's categories of proved reserves:

<u>Proved Reserves.</u> Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas 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, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

<u>Proved Developed Reserves.</u> Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved Undeveloped Reserves. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

For complete definitions of proved natural gas, natural gas liquids and crude oil reserves, refer to the SEC Regulation S-X, Rule 4-10(a)(2), (3) and (4).

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)						
	United States	**Argentina**	**Ecuador**	**Equatorial Guinea (1)**	**Israel (2)**	**North Sea**	**Total**
Proved reserves as of:							
January 1, 2004	558,058	2,448	79,298	537,998	450,307	13,811	**1,641,920**
Revisions of previous estimates	(7,452)	(937)	(27,398)	(4,130)	(15,441)	1,552	**(53,806)**
Extensions, discoveries and other additions	74,277		75,081	400,288		685	**550,331**
Production	(89,458)	(142)	(7,640)	(16,747)	(17,573)	(4,130)	**(135,690)**
Sale of minerals in place	(30,127)					(204)	**(30,331)**
Purchase of minerals in place	14,437						**14,437**
December 31, 2004	519,735	1,369	119,341	917,409	417,293	11,714	**1,986,861**
Proved reserves as of:							
January 1, 2003	621,716	3,887	84,993	425,420	450,307	14,478	**1,600,801**
Revisions of previous estimates	3,070	(1,147)	2,147	182		4,392	**8,644**
Extensions, discoveries and other additions	44,463			126,962			**171,425**
Production	(106,609)	(292)	(7,842)	(14,566)		(5,059)	**(134,368)**
Sale of minerals in place	(10,406)						**(10,406)**
Purchase of minerals in place	5,824						**5,824**
December 31, 2003	558,058	2,448	79,298	537,998	450,307	13,811	**1,641,920**
Proved reserves as of:							
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 developed gas reserves as of:							
January 1, 2005	430,513	1,118	119,341	447,347	360,428	11,714	**1,370,461**
January 1, 2004	506,457	2,197	25,130	462,474	378,001	13,811	**1,388,070**
January 1, 2003	576,378	3,664	34,436	425,420		14,478	**1,054,376**
January 1, 2002	721,926	3,996		438,214		20,661	**1,184,797**

(1) Includes reserves in excess of volumes under natural gas sales contracts for 2003 and 2002. The Company had a market with an LPG plant and a methanol plant that exceeded contract volumes.

(2) Includes reserves in excess of volumes under natural gas sales contracts. The Israeli natural gas market, as estimated by the Israeli Ministry of National Infrastructure, from 2005 to 2020, is significantly greater than Noble Energy's uncontracted net estimated proved reserves.

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 (MBbls)					
	United States	Argentina	China(1)	Equatorial Guinea	North Sea	Total
Proved reserves as of:						
January 1, 2004	42,304	8,921	10,336	113,198	8,460	**183,219**
Revisions of previous estimates	976	1,995	(1,438)	(777)	1,037	**1,793**
Extensions, discoveries and other additions	16,760		3,024		4,414	**24,198**
Production	(8,073)	(1,085)	(1,421)	(3,691)	(2,459)	**(16,729)**
Sale of minerals in place	(2,190)				(2,116)	**(4,306)**
Purchase of minerals in place	5,289					**5,289**
December 31, 2004	55,066	9,831	10,501	108,730	9,336	**193,464**
Proved reserves as of:						
January 1, 2003	62,023	9,283	10,930	111,019	8,223	**201,478**
Revisions of previous estimates	1,216	(91)	609	(333)	3,654	**5,055**
Extensions, discoveries and other additions	1,949	768		4,840		**7,557**
Production	(7,402)	(1,039)	(1,203)	(2,328)	(2,705)	**(14,677)**
Sale of minerals in place	(15,482)				(712)	**(16,194)**
Purchase of minerals in place						
December 31, 2003	42,304	8,921	10,336	113,198	8,460	**183,219**
Proved reserves as of:						
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 developed oil reserves as of:						
January 1, 2005	32,390	7,539	10,501	108,730	9,336	**168,496**
January 1, 2004	34,246	8,004	10,336	113,198	8,460	**174,244**
January 1, 2003	52,847	8,331	10,930	78,746	8,223	**159,077**
January 1, 2002	64,534	8,866		61,897	11,114	**146,411**

(1) The Company's China reserves were previously classified as proved developed reserves as of January 1, 2000. However, the reserves should have been classified as proved undeveloped reserves. The change back to proved developed reserves was made December 31, 2002.

Oil and Gas Operations (Unaudited)

Aggregate results of continuing operations, in connection with the Company's crude oil and natural gas producing activities, for each of the years are shown below.

(in thousands) **December 31, 2004**	**United States**	**Equatorial Guinea**	**Israel**	**North Sea**	**Other Int'l**	**Total**
Revenues	$ 781,766	$ 143,069	$ 48,855	$ 115,181	$ 85,328	**$ 1,174,199**
Production costs (1)	125,018	23,936	7,366	11,104	21,526	**188,950**
Transportation				10,480	8,073	**18,553**
E&P corporate	15,599	299		1	(77)	**15,822**
Exploration expenses	73,971	7,214	598	11,115	2,810	**95,708**
DD&A and valuation provision	259,365	14,674	9,549	18,215	20,729	**322,532**
Impairment of operating assets	9,885					**9,885**
Accretion expense	8,021	6	163	1,140	22	**9,352**
Income	289,907	96,940	31,179	63,126	32,245	**513,397**
Income tax expense	106,603	49,044	9,896	28,542	13,860	**207,945**
Result of continuing operations from producing activities (excluding corporate overhead and interest costs)	$ 183,304	$ 47,896	$ 21,283	$ 34,584	$ 18,385	**$ 305,452**
December 31, 2003						
Revenues	$ 605,367	$ 68,644	$	$ 100,558	$ 64,575	**$ 839,144**
Production costs (1)	112,725	16,319		10,662	18,538	**158,244**
Transportation				9,024	5,655	**14,679**
E&P corporate	15,884	603	5		1,866	**18,358**
Exploration expenses	71,802	134	6,925	9,239	28,011	**116,111**
DD&A and valuation provision	278,426	6,101	910	29,405	23,795	**338,637**
Impairment of operating assets	31,937					**31,937**
Accretion expense	8,449			882		**9,331**
Income (loss)	86,144	45,487	(7,840)	41,346	(13,290)	**151,847**
Income tax expense (benefit)	17,795	21,770	(4,121)	19,586	9,479	**64,509**
Result of continuing operations from producing activities (excluding corporate overhead and interest costs)	$ 68,349	$ 23,717	$ (3,719)	$ 21,760	$ (22,769)	**$ 87,338**
December 31, 2002						
Revenues	$ 444,121	$ 45,830	$	$ 91,538	$ 27,537	**$ 609,026**
Production costs (1)	86,342	6,795		10,813	5,180	**109,130**
Transportation				9,618	6,823	**16,441**
E&P corporate	27,768	2,045	10	630	1,090	**31,543**
Exploration expenses	102,323	1,341	1,725	5,032	20,733	**131,154**
DD&A and valuation provision	209,905	5,835	909	28,350	9,606	**254,605**
Income (loss)	17,783	29,814	(2,644)	37,095	(15,895)	**66,153**
Income tax expense	6,559	13,825		16,360	666	**37,410**
Result of continuing operations from producing activities (excluding corporate overhead and interest costs)	$ 11,224	$ 15,989	$ (2,644)	$ 20,735	$ (16,561)	**$ 28,743**

(1) Production costs consist of oil and gas operations expense, production and ad valorem taxes, plus general and administrative expense supporting the Company's oil and gas operations.

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.

(in thousands) December 31, 2004	United States	Equatorial Guinea	Israel	North Sea	Other Int'l	Total
Property acquisition costs						
Proved	$ 85,785	$	$	$	$	$ 85,785
Unproved	25,547	14,459		4,651	24	**44,681**
Total acquisition costs	$ 111,332	$ 14,459	$	$ 4,651	$ 24	**$ 130,466**
Exploration costs	$ 106,985	$ 7,214	$ 598	$ 12,256	$ 2,810	**$ 129,863**
Development costs	$ 168,948	$ 161,227	$ (8,313)	$ 6,144	$ 72,471	**$ 400,477**
Asset retirements incurred	$ 5,231	$ 426	$ 2,426	$ 3,365	$ 1,568	**$ 13,016**
Total	$ 392,496	$ 183,326	$ (5,289)	$ 26,416	$ 76,873	**$ 673,822**
December 31, 2003						
Property acquisition costs						
Proved	$ 1,419	$	$	$ (125)	$	**$ 1,294**
Unproved	10,184				50	**10,234**
Total acquisition costs	$ 11,603	$	$	$ (125)	$ **50**	**$ 11,528**
Exploration costs	$ 127,450	$ 134	$ 6,925	$ 10,086	$ 8,828	**$ 153,423**
Development costs	$ 98,717	$ 222,315	$ 66,751	$ 6,747	$ 7,249	**$ 401,779**
Asset retirements incurred	$ 2,127	$	$	$ 429	$	**$ 2,556**
Total	$ 239,897	$ 222,449	$ 73,676	$ 17,137	$ 16,127	**$ 569,286**
December 31, 2002						
Property acquisition costs						
Proved	$ 7,873	$	$	$ 115	$	**$ 7,988**
Unproved	28,023			(238)	2,730	**30,515**
Total acquisition costs	$ 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**
Total	$ 320,577	$ 53,190	$ 16,492	$ 14,831	$ 84,599	**$ 489,689**

Development costs include $11.4 million, $274.6 million and $245.6 million spent to develop proved undeveloped reserves in 2004, 2003 and 2002, respectively. Asset retirements incurred in 2004 for the United States include $130.0 million related to Hurricane Ivan damage in the Gulf of Mexico, which is not included in the schedule above, as it will be reimbursed by insurance. The Company believes it has insurance coverage in an amount sufficient to make necessary repairs in order to re-establish production as a result of Hurricane Ivan.

Aggregate Capitalized Costs (Unaudited)

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

	2004			2003		
(in thousands)	**U. S.**	**Int'l**	**Total**	**U. S.**	**Int'l**	**Total**
Unproved oil and gas properties	$ 121,673	$ 28,810	**$ 150,483**	$ 117,519	$ 9,675	**$ 127,194**
Proved oil and gas properties	2,535,148	1,604,020	**4,139,168**	2,372,100	1,373,395	**3,745,495**
	2,656,821	1,632,830	**4,289,651**	2,489,619	1,383,070	**3,872,689**
Accumulated DD&A	(1,657,291)	(319,745)	**(1,977,036)**	(1,525,667)	(265,917)	**(1,791,584)**
Net capitalized costs	$ 999,530	$ 1,313,085	**$ 2,312,615**	$ 963,952	$ 1,117,153	**$ 2,081,105**

Included in proved oil and gas properties at December 31, 2004 and 2003 are asset retirement costs of $74.0 million and $82.2 million for the U.S. and $16.6 million and $14.3 million for International, respectively.

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, 2004, 2003 and 2002 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, 2004 (in millions of dollars)	**United States**	**Ecuador**	**Equatorial Guinea**	**Israel**	**North Sea**	**Other Int'l**	**Total**
Future cash inflows (1)	$ 5,429	$ 377	$ 4,358	$ 1,089	$ 439	$ 662	**$ 12,354**
Future production costs (2)	1,135	42	490	133	153	310	**2,263**
Future development costs	364	16	83	88	23	33	**607**
Future income tax expenses	1,219	129	1,704	264	109	93	**3,518**
Future net cash flows	2,711	190	2,081	604	154	226	**5,966**
10% annual discount for estimated timing of cash flows	1,104	82	1,079	249	33	77	**2,624**
Standardized measure of discounted future net cash flows	$ 1,607	$ 108	$ 1,002	$ 355	$ 121	$ 149	**$ 3,342**
December 31, 2003 (in millions of dollars)							
Future cash inflows (1)	$ 4,425	$ 317	$ 3,391	$ 1,177	$ 316	$ 582	**$ 10,208**
Future production costs (2)	986	46	635	139	113	248	**2,167**
Future development costs	339	49	199	84	25	19	**715**
Future income tax expenses	998	86	1,200	307	78	93	**2,762**
Future net cash flows	2,102	136	1,357	647	100	222	**4,564**
10% annual discount for estimated timing of cash flows	847	50	774	294	11	76	**2,052**
Standardized measure of discounted future net cash flows	$ 1,255	$ 86	$ 583	$ 353	$ 89	$ 146	**$ 2,512**
December 31, 2002 (in millions of dollars)							
Future cash inflows (1)	$ 4,743	$ 268	$ 3,111	$ 1,181	$ 294	$ 648	**$ 10,245**
Future production costs (2)	1,119	42	445	201	98	216	**2,121**
Future development costs	387	31	216	100	12	22	**768**
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**

(1) The standardized measure of discounted future net cash flows for 2004, 2003 and 2002 does not include cash flows relating to the Company's anticipated future methanol or power sales.

(2) Production costs include oil and gas operations expense, production and ad valorem taxes, transportation costs, and general and administrative expense supporting the Company's oil and gas operations.

Future cash inflows are computed by applying year-end prices, adjusted for location and quality 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 discounted future cash flow estimates do not include the effects of the Company's derivative instruments. See the following table for average prices per region:

December 31, 2004	United States	Ecuador	Equatorial Guinea	Israel	North Sea	Other Int'l	Total
Average crude oil price per Bbl	$ 41.25	$	$ 37.97	$	$ 40.93	$ 32.52	**$ 38.48**
Average natural gas price per Mcf	$ 6.07	$ 3.16	$ .25	$ 2.61	$ 4.84	$ .84	**$ 2.47**
December 31, 2003							
Average crude oil price per Bbl	$ 30.16	$	$ 28.76	$	$ 30.64	$ 30.16	**$ 29.32**
Average natural gas price per Mcf	$ 5.64	$ 4.00	$ .25	$ 2.61	$ 4.15	$ .38	**$ 2.95**
December 31, 2002							
Average crude oil price per Bbl	$ 29.19	$	$ 27.10	$	$ 28.88	$ 32.00	**$ 28.31**
Average natural gas price per Mcf	$ 4.72	$ 3.15	$ .24	$ 2.62	$ 3.89	$ .30	**$ 2.84**

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 $105.7 million or $55.7 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 development costs include $100.3 million, $132.0 million and $13.4 million that the Company expects to spend in 2005, 2006 and 2007, respectively, to develop proved undeveloped reserves.

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, 2004, the Company estimated imbalance receivables of $21.2 million and estimated imbalance liabilities of $16.1 million; at year-end 2003, $23.0 million in receivables and $18.8 million in liabilities; and at year-end 2002, $20.8 million in receivables and $17.1 million in liabilities. Neither the imbalance receivables nor 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, 2004, 2003 and 2002.

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)	2004	2003	2002
Standardized measure of discounted future net cash flows at the beginning of the year	$ 2,512	$ 2,732	$ 1,428
Extensions, discoveries and improved recovery, less related costs	839	247	486
Revisions of previous quantity estimates	(70)	115	(158)
Changes in estimated future development costs	99	(148)	(243)
Purchases (sales) of minerals in place	12	(115)	(13)
Net changes in prices and production costs	861	(312)	1,636
Accretion of discount	406	405	208
Sales of oil and gas produced, net of production costs	(1,014)	(793)	(553)
Development costs incurred during the period	92	243	254
Net change in income taxes	(380)	(216)	(667)
Change in timing of estimated future production, and other	(15)	354	354
Standardized measure of discounted future net cash flows at the end of the year	$ 3,342	$ 2,512	$ 2,732

Supplemental Quarterly Financial Information
(Unaudited)

Supplemental quarterly financial information for the years ended December 31, 2004 and 2003 is as follows:

	Quarter Ended			
(in thousands except per share amounts)	**Mar. 31.**	**June 30.**	**Sept. 30.**	**Dec. 31.**
2004 (1)				
Revenues	$ 317,616	$ 335,233	$ 320,174	$ 378,153
Income (loss) from continuing operations before taxes	$ 128,848	$ 115,983	$ 128,591	$ 142,619
Income (loss) from continuing operations	$ 75,312	$ 70,628	$ 80,971	$ 86,939
Discontinued operations, net of tax	$ 10,234	$ 1,399	$ 2,721	$ 506
Net income (loss)	$ 85,546	$ 72,027	$ 83,692	$ 87,445
Basic earnings (loss) per share:				
Income from continuing operations	$ 1.30	$ 1.22	$ 1.38	$ 1.49
Discontinued operations, net of tax	$ 0.18	$ 0.02	$ 0.05	$ 0.01
Net income (loss)	$ 1.48	$ 1.24	$ 1.43	$ 1.50
Diluted earnings (loss) per share:				
Income from continuing operations	$ 1.29	$ 1.20	$ 1.36	$ 1.45
Discontinued operations, net of tax	$ 0.17	$ 0.02	$ 0.05	$ 0.01
Net income (loss)	$ 1.46	$ 1.22	$ 1.41	$ 1.46
2003 (2)				
Revenues	$ 265,532	$ 246,540	$ 241,411	$ 252,467
Income (loss) from continuing operations before taxes	$ 58,236	$ 39,631	$ 48,238	$ (4,466)
Income (loss) from continuing operations	$ 32,712	$ 25,810	$ 31,567	$ (196)
Cumulative effect of change in accounting principle, net of tax	$ (5,839)	$	$	$
Discontinued operations, net of tax	$ 7,984	$ 3,260	$ 3,549	$ (20,854)
Net income (loss)	$ 34,857	$ 29,070	$ 35,116	$ (21,050)
Basic earnings (loss) per share:				
Income from continuing operations	$ 0.57	$ 0.45	$ 0.56	$ 0.00
Cumulative effect of change in accounting principle, net of tax	$ (0.10)	$	$	$
Discontinued operations, net of tax	$ 0.14	$ 0.06	$ 0.06	$ (0.37)
Net income (loss)	$ 0.61	$ 0.51	$ 0.62	$ (0.37)
Diluted earnings (loss) per share:				
Income from continuing operations	$ 0.56	$ 0.45	$ 0.55	$ 0.00
Cumulative effect of change in accounting principle, net of tax	$ (0.10)	$	$	$
Discontinued operations, net of tax	$ 0.14	$ 0.05	$ 0.06	$ (0.37)
Net income (loss)	$ 0.60	$ 0.50	$ 0.61	$ (0.37)

(1) Third quarter 2004 includes a loss on early extinguishment of debt of $2.9 million ($1.9 million, net of tax). Fourth quarter 2004 includes a non-cash charge of $9.9 million ($6.4 million, net of tax) related to the impairment of operating assets and a gain of $4.4 million ($2.9 million, net of tax) related to an exchange of nonmonetary assets. Fourth quarter 2004 also includes a charge of $154.0 million related to the involuntary conversion of Main Pass assets and a related credit for insurance recoveries of $153.0 million, resulting in a net loss of $1 million.

(2) First quarter 2003 includes a non-cash loss from cumulative effect of change in accounting principle, net of tax of $5.8 million ($.10 per share) due to the adoption of SFAS No. 143. Fourth quarter 2003 includes a non-cash charge of $31.9 million ($20.7 million, net of tax) related to the impairment of operating assets.

Atlantic Methanol Production Company, LLC

Financial Statements

For the Years Ended December 31, 2004, 2003 and 2002

Report of Independent Registered Public Accounting Firm

To the Members of
Atlantic Methanol Production Company, LLC
Houston, Texas

We have audited the accompanying balance sheet of Atlantic Methanol Production Company, LLC (the “Company”) as of December 31, 2004, and the related statements of income, members’ equity 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 financial statements based on our audit.

We conducted our audit in accordance with standards of the Public Company Accounting Oversight Board (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 audit provides 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 Atlantic Methanol Production Company, LLC as of December 31, 2004, and the results of its operations and its cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States.

UHY Mann Frankfort Stein & Lipp, CPA’s LLP

Houston, Texas
January 18, 2005

Report of Independent Auditors

The Members
Atlantic Methanol Production Company, LLC

We have audited the accompanying balance sheet of Atlantic Methanol Production Company, LLC as of December 31, 2003 and 2002, and the related statements of operations, members' equity and cash flows for the years then ended. 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 Atlantic Methanol Production Company, LLC as of December 31, 2003 and 2002, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States.

Ernst & Young LLP

January 28, 2004
Fort Worth, Texas

Atlantic Methanol Production Company, LLC

Balance Sheets

(dollars in thousands)	December 31, 2004	December 31, 2003
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 16,161	$ 10,970
Accounts receivable - trade	12,669	6,177
Accounts receivable - affiliates	21,286	10,029
Other receivables	690	228
Inventories	11,740	12,054
Deferred methanol cost	4,527	3,296
Deferred tax asset - foreign	16,495	
Deferred expenses	2,611	1,574
Prepaid expenses and deposits	5,785	5,025
Total current assets	91,964	49,353
Property, Plant and Equipment, net	370,495	373,564
Total Assets	$ 462,459	$ 422,917
LIABILITIES AND MEMBERS' EQUITY		
Current Liabilities:		
Accounts payable - trade	$ 1,274	$ 527
Accounts payable - affiliates	3,588	231
Accrued liabilities	17,490	11,419
Other taxes payable	434	633
Deferred revenue	31,014	15,346
Distributions payable	1,375	
Total current liabilities	55,175	28,156
Members' Equity	407,284	394,761
Total Liabilities and Members' Equity	$ 462,459	$ 422,917

See accompanying notes.

Atlantic Methanol Production Company, LLC

Statements of Income

(dollars in thousands)	December 31, 2004	2003	2002
Income:			
Methanol sales	$ 217,702	$ 171,127	$ 97,476
Shipping revenues	1,356	2,306	1,954
Legal settlements	10,895		
Sales of purchased third-party methanol		341	11,384
Foreign exchange gains	316		
Other revenues	13,733	11,829	1,800
Total Income	244,002	185,603	112,614
Costs and Expenses:			
Cost of methanol	$ 21,815	$ 27,550	$ 21,824
Shipping	26,563	19,011	17,709
Marketing	6,210	5,189	2,833
Cost of third-party purchased methanol sold		428	15,312
Net bridge cost recovery loss	253	318	2,134
Depreciation	18,651	19,197	18,791
General and administrative	26,727	22,664	15,675
Net profit interest	11,485	5,201	
Ship charter expense	333	1,079	
Total Costs and Expenses	112,037	100,637	94,278
Income Before Tax	131,965	84,966	18,336
Deferred Tax Benefit - Foreign	16,495		
Net Income	$ 148,460	$ 84,966	$ 18,336

See accompanying notes.

Atlantic Methanol Production Company, LLC

Statements of Members' Equity

(dollars in thousands)	December 31, 2004	2003	2002
Balance at beginning of year:	$ 394,761	$ 412,295	$ 413,919
Net income	148,460	84,966	18,336
Distributions declared to members	(128,500)	(102,500)	(35,300)
Return of capital	(7,437)		
Contributions			15,340
Balance at end of year	$ 407,284	$ 394,761	$ 412,295

See accompanying notes.

Atlantic Methanol Production Company, LLC

Statements of Cash Flows

(dollars in thousands)	December 31, 2004	2003	2002
Cash Flows from Operating Activities			
Net income	$ 148,460	$ 84,966	$ 18,336
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation expense	18,651	19,197	18,791
Deferred income tax	(16,495)		
Changes in operating assets and liabilities:			
Accounts receivables - trade	(6,492)	7,374	(11,837)
Accounts receivables - affiliates	(11,257)	(2,569)	(3,189)
Other receivables	(462)	(228)	
Inventories	314	(996)	7,760
Prepaid expenses and deposits	(760)	(2,148)	(197)
Deferred methanol cost	(1,231)	2,263	(5,560)
Deferred expenses	(1,037)	(1,574)	
Accounts payable - trade	747	(3,786)	3,078
Accounts payable - affiliates	3,357	(214)	(3,434)
Accrued liabilities	6,071	7,131	(3,047)
Other taxes payable	(199)		
Deferred revenue	15,668	(749)	16,095
Net cash provided by operating activities	$ 155,335	$ 108,667	$ 36,796
Cash Flows from Investing Activities			
Capital expenditures	$ (15,582)	$ (4,758)	$ (13,318)
Net cash used in investing activities	$ (15,582)	$ (4,758)	$ (13,318)
Cash Flows from Financing Activities			
Distribution to members	(127,125)	(105,030)	(33,770)
Return of capital	(7,437)		
Capital contributions			15,340
Net cash used in financing activities	$ (134,562)	$ (105,030)	$ (18,430)
Net increase (decrease) in cash and cash equivalents	5,191	(1,121)	5,048
Cash and cash equivalents, beginning of year	10,970	12,091	7,043
Cash and cash equivalents, end of year	$ 16,161	$ 10,970	$ 12,091
Non-Cash Investing and Financing Activities			
Distributions payable	$ 1,375	$	$

See accompanying notes.

NOTES TO FINANCIAL STATEMENTS

ATLANTIC METHANOL PRODUCTION COMPANY, LLC

NOTE A - FORMATION AND NATURE OF BUSINESS

Atlantic Methanol Production Company, LLC (the "Company") was formed to construct, operate and own a methanol production facility (the Plant) and related facilities on Bioko Island, Equatorial Guinea. The Company is 90% owned by Atlantic Methanol Associates, LLC (AMA) and 10% owned by Guinea Equatorial Oil and Gas Marketing Ltd. (GEOGM). AMA is owned 50% by Marathon E.G. Methanol Limited, which is ultimately a wholly owned subsidiary of Marathon Oil Corporation (Marathon) and 50% owned by Samedan Methanol, which is an indirect subsidiary of Noble Energy, Inc. (Noble), collectively referred to as its Members.

Production of methanol began in May 2001. The Plant utilizes natural gas supplied by the nearby Alba Field under a 25-year fixed-price contract of $0.25 per MMBtu. Subsidiaries of Marathon and Noble own 63.3% and 33.7%, respectively, of the Alba Field.

NOTE B - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash Equivalents: The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Inventories: Inventories consist of methanol held in tanks of approximately $2,247,000 and $2,832,000 for the years ended December 31, 2004 and 2003, respectively, with costs being determined by the weighted average cost method and spare parts for the Plant, stated at the lower of cost or market, which consisted of approximately $9,493,000 and $9,222,000 of costs for the years ended December 31, 2004 and 2003, respectively. Of the spare parts inventories, approximately $2,823,000 represents catalyst for the Plant for each of the years presented.

Property, Plant and Equipment: Property, plant and equipment are recorded at cost. Depreciation is provided on a straight-line basis over the assets estimated useful lives, ranging from 3 years to 25 years.

The Company reviews the carrying value of property, plant and equipment for impairment whenever events and circumstances indicate that the carrying value of an asset may not be recoverable from the estimated future cash flows expected to result from its use and eventual disposition. In cases where undiscounted expected future cash flows are less than the carrying value, a write-down is recognized equal to an amount by which the carrying value exceeds fair value or the estimated future discounted cash flows. No indicators of impairment were present in 2004 and 2003.

Deferred Revenue and Deferred Methanol Cost: Under the Company's sales agreements with Solvadis Chemag (MG) (NOTE F) and AMPCO Marketing, LLC (Marketing) (NOTE C) (collectively the Marketers), risk of physical loss to the methanol transfers when it is loaded on a tanker and leaves port in Equatorial Guinea. At this point, the Marketers are invoiced a provisional amount for the methanol and are required to pay 30 days subsequent to arrival of the methanol in the U.S. or Europe. Since final pricing is not known until the Marketers' resell the product under their third-party contracts, revenue and the related cost of methanol is deferred until the Marketers resell the methanol to third parties. There were approximately 92,623 and 39,978 metric tons of methanol held by Marketing and MG, respectively, at December 31, 2004, and approximately 49,967 and 30,905 metric tons of methanol held by Marketing and MG, respectively, at December 31, 2003 that had not been sold to third parties. At December 31, 2004 and 2003, revenue from provisional billings of approximately $31 million and $15.3 million, respectively, associated with these volumes were recorded as deferred revenue on the accompanying balance sheet. Cost of methanol related to these volumes of approximately $4.5 million and $3.3 million, at December 31, 2004 and 2003, respectively, are reflected as deferred methanol cost on the accompanying balance sheets.

Deferred Expenses: Deferred expenses are shipping costs that have been incurred but are associated with methanol that is included in deferred revenue. These costs are expensed as the associated methanol in deferred revenue is sold.

Foreign Currency: The U.S. dollar is considered the functional currency of the Company. Transactions that are completed in a foreign currency are translated into U.S. dollars and recorded to earnings. Some costs and revenues are invoiced in Euros, British Pound Sterling and the Communaute Financiere Africaine Franc (XAF). These costs and revenues are translated to US dollars on a monthly basis based upon the exchange rate on the last day of the current month.

Use of Estimates: The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Income Taxes: U.S. federal income taxes have not been provided for in the accompanying financial statements as the Company does not incur U.S. federal income taxes. Instead, its taxable income is included in the U.S. federal and income tax returns of its Members. The Company is subject to foreign corporate income taxes with the Republic of Equatorial Guinea ("Republic") (See Note E). Foreign deferred income taxes are provided to reflect the future tax consequences of differences between the tax bases of assets and liabilities and their reported amounts in the financial statements. Foreign deferred income tax assets and liabilities are computed using the currently enacted tax laws and rates that apply to the periods in which they are expected to affect taxable income. A valuation allowance is established when it is more likely than not that some portion or all of the foreign deferred tax assets will not be realized.

Fair Value of Financial Instruments: The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable, and accounts payable. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable are representative of their respective fair values due to the short-term maturity of these instruments.

Asset Retirement Obligations: On January 1, 2003, the Company adopted the provisions of Statement of Financial Accounting Standards ("SFAS") 143, "Accounting for Asset Retirement Obligations," which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirements costs. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. There are no obligations recorded for either the year ended December 31, 2004 or 2003, as management believes that the Company does not have any legal obligations associated with the retirement of long-lived assets.

NOTE C - RELATED PARTIES

AMPCO Services LLC (Services): Marathon and Noble, through their respective subsidiaries, formed Services to provide technical and consulting services to their jointly owned methanol production and marketing companies related to the transportation, storage, marketing, sale and delivery of methanol. Services bills the Company the cost, plus a 7% mark-up, of fixed asset purchases and expenses incurred on behalf of the Company, excluding depreciation. Services is equally owned by Noble and Marathon through their various subsidiaries.

At December 31, 2004 and 2003, the Company had approximately $0.3 million and $0.2 million in payables, respectively, for consulting services provided by Services which is included in accounts payable - affiliates on the accompanying balance sheet. During 2004 and 2003, the Company incurred costs of approximately $2.4 million and $2.6 million, respectively from Services. Such amounts are included in cost of methanol on the accompanying statements of income.

AMPCO Marketing LLC (Marketing): Effective January, 2001, the Company entered into an agreement to sell to Marketing 300,000 to 600,000 metric tons of methanol on an annual basis through 2005. The price received under the agreement is based on the price that Marketing is able to resell the methanol to third parties, less commissions, transportation and storage costs. In turn, Marketing has entered into annual contracts with third parties to sell methanol on a monthly basis. Pricing under these contracts is generally based on an index price less certain discounts for volume purchases. Marketing is equally owned by Noble and Marathon through their respective subsidiaries.

Marathon and Noble: Marathon and Noble, through their respective subsidiaries, provide the Company with gas for use in the Plant from the nearby Alba Field. The gas is priced at $0.25 per MMBtu. The Alba Field is owned 63.3% and 33.7% by subsidiaries of Marathon and Noble, respectively (NOTE F).

NOTE D - PROPERTY PLANT & EQUIPMENT

Property, plant, and equipment and related accumulated depreciation consist of the following:

	December 31, 2004	December 31, 2003
	(in thousands)	
Plant	$ 411,706	$ 403,489
Machinery and equipment	4,255	4,201
Furniture and fixtures	2,471	2,374
Software costs	2,788	1,429
Vehicles	1,786	1,611
Other	2,014	1,848
	425,020	414,952
Less: accumulated depreciation	65,979	47,328
	359,041	367,624
Construction in progress	11,454	5,940
Property, plant and equipment, net	$ 370,495	$ 373,564

NOTE E - INCOME TAXES

Under the Manufacturing and Marketing Agreement ("MMA") entered into with the Republic, the Company is exonerated from Republic corporate income taxes for the three years after commercial operations begin. The three-year income tax holiday excludes the year of first commercial operation. Therefore, the Company will be liable for income taxes beginning in 2005. During the income tax holiday the Company is recording depreciation for book purposes but is not required to take any reductions to the related assets carrying value for tax purposes. Accordingly, the Company is creating a deferred tax asset equal to the amount of depreciation taken for book purposes multiplied by the statutory tax rate of 25%. As of December 31, 2004 this represents an asset of approximately $16,495,000. The valuation allowance decreased by $11,832,000 in the year ended December 31, 2004, as management believes it is more likely than not that the entire deferred tax asset will be realized through future taxable income.

NOTE F - COMMITMENTS AND CONTINGENCIES

Pursuant to the Company's Limited Liability Company Agreement, no member or manager shall be liable for the debts, obligations, or liabilities of the Company, including under a judgment, decree or order of a court, except as may be provided in a separate, written agreement executed by such member or manager wherein they expressly agree to assume such obligations. The Company will continue to exist in perpetuity absent unanimous approval of the Members.

Litigation: During 2004, the Company settled litigation related to a claim for Material Damage and Advance Loss of Profits for loss days during 2002. The settlement was approximately $10,895,000 and is reflected in the accompanying statements of income.

The Company is involved in disputes arising in the ordinary course of business. Management does not believe the outcome of any such disputes will have a material adverse effect on the Company's financial position or results of operations.

Gas Purchase Commitment: The Company has a take-or-pay commitment contract to purchase annual quantities of natural gas for use by the Plant. The term of the contract is 25 years from first supply (May 2, 2001) and can be extended based on agreement of the parties. The minimum annual contract quantity of gas that must be purchased is 28,000,000 MMBtu on a gross heating value basis from the Alba Field (NOTE A). The gas is priced at $0.25 per MMBtu. The Alba Field is owned 63.3% and 33.7% by subsidiaries of Marathon and Noble, respectively. The minimum commitment under this contract is as follows:

Year Ending December 31,		
2005	$	7,000,000
2006		7,000,000
2007		7,000,000
2008		7,000,000
2009		7,000,000
Thereafter		114,333,000
	$	149,333,000

Sales Commitments: In addition to the sales contract between the Company and Marketing disclosed in NOTE C, the Company also entered into contracts with MG and British Petroleum Oil International ("BP"), unrelated third parties, to sell 300,000 and 140,000 metric tons, respectively, of methanol on an annual basis through 2005. The price received under the MG agreement is based on the price MG resells the methanol to third parties, less commissions, transportation and storage costs. In turn, MG has entered into annual contracts with third parties to sell methanol on a monthly basis. Pricing under MG's contracts with third parties are based upon annual contract discounts as applies to the quarterly European contract price. Several customers' contracts also include a spot component based upon the spot price at the time of purchase. In the case of BP, which internally consumes the methanol acquired, the price is based upon the European index with the spot price impacting the final price. The BP contract contains a price cap of EURO 180 per ton of methanol sold.

Concentrations of Risk: The Company sells all of its production under agreements with Marketing, MG and BP, as previously disclosed, who in turn resell the methanol to numerous third parties. In addition, the Company's ability to produce methanol is dependant upon the natural gas feedstock received from the Alba Field as disclosed above.

NOTE G - LEASES

The Company has leased office space from the Republic for use in training local employees for work at the Plant. The lease requires semi-annual payments of $120,000 and expires in August 2007.

The Company entered into operating lease agreements on March 23, 1999 for two oil/methanol tankers (vessels) to transport methanol produced by the Plant to the markets serviced by MG, BP and Marketing. Each vessel has a capacity of approximately 42,000 metric tons of methanol. The vessel lease agreements are for a period of 15 years and can be extended for an additional five-year period at the option of the company. During the term of the leases, the Company is required to pay, for each vessel, $14,300 per day accelerating to $17,500 per day in year 11 of the leases. At any time during the term of the lease, the Company has the option to terminate the leases by giving three months written notice. To cancel one of the leases, the Company would also be required to make a lump-sum termination payment of the lesser of $10 million if cancelled during years one through eight, $8 million if cancelled during years nine through twelve, or $7 million if cancelled after twelve years. On February 20, 2004, the Company entered into an operating lease agreement for a methanol/oil tanker with a capacity of approximately 28,500 metric tons. The initial term on the lease is two years with a day rate of $13,850 in year one, and $14,100 in year two. The Company has the option to extend this lease for an additional two years with a day rate of $14,200 in the first option year and a day rate of $14,300 in the second option year. The cost of the vessel leases and related operation costs of the vessels are reflected as shipping expense on the accompanying statements of income.

During periods of non-use, the Company has the option to sublease the vessels to other parties. Revenue associated with subleasing the vessels is reflected as shipping revenue on the accompanying statements of income.

Future lease and minimum lease payments under these leases are as follows:

Year Ending December 31,		
2005	$	17,830,000
2006		13,401,000
2007		12,596,000
2008		12,456,000
2009		12,564,000
Thereafter		53,550,000
	$	122,397,000

NOTE H - BRIDGE COST RECOVERY LOSS AND THIRD PARTY REVENUE AND COST

The Company uses Marketing to sell the Company's methanol in the United States. Sales contracts are typically negotiated in the third quarter of each year for the upcoming year's production and sold under calendar-year-basis agreements. Accordingly, sales contracts signed in the fall of 2002 applied to 2003 production. The Plant was shut in for one month during the year 2003 due to compressor repairs. As a result, the Company did not provide methanol to Marketing for sale under the annual sales contracts. Consequently, Marketing had to purchase methanol on the spot market for resale in 2003. The cost of the methanol, net of the price received by Marketing for sales under the sale commitments, was billed to the Company and is reflected as bridge cost recovery loss on the accompanying statements of income in both 2003 and 2004.

Also, as a result of the plant being shut in, the Company purchased methanol on the spot market to meet sales commitments in Europe that were entered into during 2003 by MG. The cost of the methanol purchased is reflected as cost of third-party purchased methanol sold and the associated revenue from the sale of this methanol is reflected as sales of purchased third-party methanol on the accompanying statements of income.

NOTE I - NET PROFIT INTEREST

Under the Manufacturing and Marketing Agreement entered into with the Republic of Equatorial Guinea, the Republic is granted a Net Profit Interest equal to 10% of Net Profits, as defined. The Net Profits Interest went into effect in 2003.

NOTE J - SHIPPING REVENUE AND SHIP CHARTER EXPENSE

During 2004 and 2003, the Company subleased its methanol tankers. The revenue earned in subleasing the vessels is captured as shipping revenues. The associated cost is captured as Ship charter expense.

NOTE K - RETURN OF CAPITAL

During the 2004 fiscal year, the Company identified an error in contributions that occurred in the 2002 fiscal year. AMA had contributed approximately $7,437,000 in excess of the subscription price of $420,000,000 set forth in the Members' Agreement without the issuance of new shares. During 2002, the contribution in excess of the subscription price should have been treated as a loan from AMA to the Company. To correct this error in 2004, the Company reduced capital by the $7,437,000 and created a loan payable to AMA, which it paid in full in 2004. The impact on previously issued financial statements was only a reclassification on the balance sheet between Members' Equity and Debt with no impact to the statements of income.

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

No changes or disagreements.

Item 9a. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

The Company maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed by the Company in the reports it files or furnishes to the SEC under the Securities Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that information is accumulated and communicated to management, including its principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

In connection with the testing of its internal controls and procedures during the third quarter of 2004, certain significant deficiencies in the Company's internal control procedures and IT systems were identified, including: certain spreadsheet controls, input and approval controls, and segregation of duties and financial reporting controls. The Company promptly took actions to remediate these deficiencies and successfully completed the evaluation and testing of newly implemented internal controls during the fourth quarter.

Noble Energy's principal executive officer and principal financial officer have since evaluated the effectiveness of Noble Energy's "disclosure controls and procedures," as such term is defined in Rule 13a-15(e) and 15d-15(c) of the Securities Exchange Act of 1934, as amended, as of the end of the period covered by this Annual Report on Form 10-K. Based upon their evaluation, they have concluded that the Company's disclosure controls and procedures are effective.

In designing and evaluating the Company's disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events and the application of judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of these and other inherent limitations of control systems, there is only reasonable assurance that the Company's controls will succeed in achieving their goals under all potential future conditions.

Changes in Internal Control over Financial Reporting

In addition, the Company is continuously seeking to improve the efficiency and effectiveness of its internal controls. This results in periodic refinements to internal control processes throughout the Company. However, there have been no significant changes in the Company's internal controls over financial reporting or in other factors that could significantly affect these controls that occurred during the Company's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9b. Other Information.

None.

PART III

Item 10. Directors and Executive Officers of the Registrant.

The sections entitled "Election of Directors" and "Information Concerning the Board of Directors" in the Registrant's proxy statement for the 2005 annual meeting of stockholders sets forth certain information with respect to the directors of the Registrant and certain committees of the Board of Directors of the Registrant and are 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 2005 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.

The section entitled "Corporate Governance" in the Registrant's proxy statement for the 2005 annual meeting of stockholders sets forth certain information required by this item and is incorporated herein by reference.

Item 11. Executive Compensation.

The section entitled "Executive Compensation" in the Registrant's proxy statement for the 2005 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," "Security Ownership of Directors and Executive Officers" and "Equity Compensation Plan Table" in the Registrant's proxy statement for the 2005 annual meeting of stockholders set forth certain information with respect to 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 2005 annual meeting of stockholders sets forth certain information with respect to certain relationships and related transactions, and is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services.

The section entitled "Matters Relating to the Independent Auditors" in the Registrant's proxy statement for the 2005 annual meeting of stockholders sets forth certain information with respect to principal accounting fees and services, and is incorporated herein by reference.

PART IV

Item 15. Exhibits.

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

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

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.
(Registrant)

Date: March 14, 2005

By: /s/ Charles D. Davidson
Charles D. Davidson,
Chairman of the Board, President,
Chief Executive Officer and Director

Date: March 14, 2005

By: /s/ Chris Tong
Chris Tong,
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 14, 2005
/s/ Chris Tong Chris Tong	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	March 14, 2005
/s/ Michael A. Cawley Michael A. Cawley	Director	March 14, 2005
/s/ Edward F. Cox Edward F. Cox	Director	March 14, 2005
/s/ Kirby L. Hedrick Kirby L. Hedrick	Director	March 14, 2005
/s/ Bruce A. Smith Bruce A. Smith	Director	March 14, 2005

INDEX TO EXHIBITS

Exhibit Number		Exhibit **
2.1	—	Agreement and Plan of Merger, dated as of December 15, 2004 by and among Noble Energy, Inc., Noble Energy Production, Inc. and Patina Oil & Gas Corporation (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K (Date of Event: December 16, 2004) dated December 16, 2004 and incorporated herein by reference).
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	—	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).
4.1	—	Certificate of Designations of Series A Junior Participating Preferred Stock of the Registrant dated August 27, 1997 (filed as 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).
4.2	—	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).
4.3	—	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).
4.4	—	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).
4.5	—	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).
4.6	—	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).
4.7	—	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).
4.8	—	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).

Exhibit Number		Exhibit **
4.9	—	Third Indenture Supplement relating to $200 million of the Registrant's 5.25% Notes due 2014 dated April 19, 2004 between the Company and the Bank of New York Trust Company, N.A., as successor trustee to U.S. Trust Company of Texas, N.A. (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-4 (Registration No. 333-116092) and incorporated herein by reference).
10.1 *	—	Restoration of Retirement Income Plan for Certain Participants in the Noble Energy, Inc. 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 as Exhibit 10.2 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).
10.3 *	—	Noble Energy, Inc. Restoration Trust effective August 1, 2002 (filed as Exhibit 10.3 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).
10.4 *	—	Noble Energy, Inc. Deferred Compensation Plan (formerly known as the Noble Affiliates Thrift Restoration Plan dated May 9, 1994) as restated effective August 1, 2001 (filed as Exhibit 10.4 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).
10.5 *	—	Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, as amended, dated January 27, 2003, and approved by the stockholders of the Company on April 29, 2003 (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2003 and incorporated herein by reference).
10.6 *	—	Form of Nonqualified Stock Option Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: February 1, 2004) filed February 7, 2004 and incorporated herein by reference).
10.7 *	—	Form of Restricted Stock Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Event: February 1, 2004) filed February 7, 2004 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 27, 2004 (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 and incorporated herein by reference).
10.10*	—	Noble Energy, Inc. 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).

Exhibit Number		Exhibit **
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).
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 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2004 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).
10.20	—	364-day Credit Agreement dated as of October 30, 2003 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, 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 as exhibit 10.20 to the Registrant's Annual Report on Form 10-K for the year ended December 31,2003 and incorporated herein by reference).
10.21	—	Term Loan Agreement dated as of January 30, 2004 among Noble Energy Mediterranean Ltd., as borrower, Sumitomo Mitsui Banking Corporation, as initial lender and agent for the lenders, and certain commercial lending institutions, as lenders (filed as Exhibit 99.1 to the Registrant's Current Report on Form 8-K (Date of Event: January 30, 2004) filed May 10, 2004 and incorporated herein by reference).
10.22	—	Guaranty of the Company dated January 30, 2004 guaranteeing obligations of Noble Energy Mediterranean, Ltd. under the Term Loan Agreement dated January 30, 2004 (filed as Exhibit 99.2 to the Registrant's Current Report on Form 8-K (Date of Event: January 30, 2004) filed May 10, 2004 and incorporated herein by reference).
10.23	—	Term Loan Agreement dated as of February 2, 2004 among Noble Energy Mediterranean Ltd., as borrower, Bank One, NA, as agent for the lenders, and certain commercial lending institutions, as lenders (filed as Exhibit 99.3 to the Registrant's Current Report on Form 8-K (Date of Event: January 30, 2004) filed May 10, 2004 and incorporated herein by reference).
10.24	—	Guaranty of the Company dated February 2, 2004 guaranteeing obligations of Noble Energy Mediterranean, Ltd. under the Term Loan Agreement dated February 2, 2004 (filed as Exhibit 99.4 to the Registrant's Current Report on Form 8-K (Date of Event: January 30, 2004) filed May 10, 2004 and incorporated herein by reference).
10.25	—	Term Loan Agreement dated as of February 4, 2004 among Noble Energy Mediterranean Ltd., as borrower, The Royal Bank of Scotland Finance (Ireland), as agent for the lenders and as the initial lender (filed as Exhibit 99.5 to the Registrant's Current Report on Form 8-K (Date of Event: January 30, 2004) filed May 10, 2004 and incorporated herein by reference).

Exhibit Number		Exhibit **
10.26	—	Guaranty of the Company dated February 4, 2004 guaranteeing obligations of Noble Energy Mediterranean, Ltd. under the Term Loan Agreement dated February 4, 2004 (filed as Exhibit 99.6 to the Registrant's Current Report on Form 8-K (Date of Event: January 30, 2004) filed May 10, 2004 and incorporated herein by reference).
10.27	—	$400 million Five-Year Credit Agreement, dated October 28, 2004 among Noble Energy, Inc., JPMorgan Chase Bank, as administrative agent, Wachovia Bank, National Association, as syndication agent, Barclays Bank, PLC, Duetsche Bank AG New York Branch and The Royal Bank of Scotland, PLC, as co-documentation agents, and certain other commercial lending institutions named therein (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: October 28, 2004) dated November 3, 2004 and incorporated herein by reference).
10.28*	—	Noble Energy, Inc. 2004 Long-Term Incentive Plan effective as of January 1, 2004 (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 and incorporated herein by reference).
10.29*	—	Form of Performance Units Agreement under the Noble Energy, Inc. 2004 Long-Term Incentive Program (filed as Exhibit 10.3 to the Registrant's Current Report on Form 8-K (Date of Event: February 1, 2004) filed February 7, 2004 and incorporated herein by reference).
12.1	—	Computation of ratio of earnings to fixed charges.
21	—	Subsidiaries, filed herewith.
23.1	—	Consent of KPMG LLP, filed herewith.
23.2	—	Consent of Ernst & Young LLP, filed herewith.
23.3	—	Consent of UHY Mann Frankfort Stein & Lipp CPA's LLP, filed herewith.
31.1	—	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
31.2	—	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
32.1	—	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).
32.2	—	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., 100 Glenborough Drive, Suite 100, Houston, Texas 77067.

Exhibit 12.1

NOBLE ENERGY, INC.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(in thousands)

	Year ended December 31, 2004	2003	2002	2001	2000
Income from continuing operations before cumulative effect of change in accounting principle	$ 516,041	$ 141,639	$ 27,896	$ 150,130	$ 207,890
Add (deduct):					
Fixed charges	62,747	62,075	64,566	54,434	50,434
Interest capitalized	(13,401)	(14,134)	(16,331)	(15,953)	(6,326)
Distributions less equity in earnings of equity investees	(11,275)	5,499	8,164	(6,981)	(13,544)
Earnings as defined	$ 554,112	$ 195,079	$ 84,295	$ 181,630	$ 238,454
Interest expense, excluding capitalized interest	$ 48,227	$ 46,977	$ 47,709	$ 38,007	$ 43,697
Interest capitalized	13,401	14,134	16,331	15,953	6,326
Interest portion of rental expense	1,119	964	526	474	411
Fixed charges as defined	$ 62,747	$ 62,075	$ 64,566	$ 54,434	$ 50,434
Ratio of earnings to fixed charges	8.83	3.14	1.31	3.34	4.73

EXHIBIT 21

TO FORM 10-K

SUBSIDIARIES

NAME	STATE OF JURISDICTION OF ORGANIZATION	REF
LaTex Resources Inc.	Colorado	(1)
Noble Energy Marketing, Inc.	Delaware	(1)
Noble Energy Production, Inc.	Delaware	(1)
Noble Gas Pipeline, Inc.	Delaware	(2)
Samedan of North Africa, Inc.	Delaware	(1)
Noble Energy West Africa Ltd.	Delaware	(3)
Noble Energy Hannah Ltd.	Cayman Islands	(3)
EDC Ireland	Cayman Islands	(3)
Noble Energy International Ltd.	Cayman Islands	(3)
Noble Energy EG Ltd.	Cayman Islands	(4)
Noble Energy JDZ Ltd.	Cayman Islands	(4)
Alba Associates LLC	Cayman Islands	(9)
Alba Plant LLC	Cayman Islands	(10)
Machalapower Cia. Ltda.	Cayman Islands	(4)
Noble Energy Mediterranean Ltd.	Cayman Islands	(4)
Yam Tethys Ltd.	Israel	(14)
Samedan Transfer Sub	Cayman Islands	(4)
AMPCO Marketing, L.L.C.	Michigan	(5)
AMPCO Services, L.L.C.	Michigan	(5)

Samedan Vietnam Limited	Cayman Islands	(3)
Atlantic Methanol Capital Company	Cayman Islands	(5)
Samedan Methanol	Cayman Islands	(6)
Atlantic Methanol Associates LLC	Cayman Islands	(7)
Atlantic Methanol Production Company LLC	Cayman Islands	(8)
Samedan, Mediterranean Sea, Inc.	Delaware	(1)
Samedan North Sea, Inc.	Delaware	(1)
Samedan Oil of Canada, Inc.	Delaware	(1)
Samedan Oil of Indonesia, Inc.	Delaware	(1)
Samedan Pipe Line Corporation	Delaware	(1)
Samedan Royalty Corporation	Delaware	(1)
Samedan of Tunisia, Inc.	Delaware	(1)
Noble Energy (Louisiana), LLC	Delaware	(1)
Noble Energy, LLC	Delaware	(1)
Noble Energy, LP	Delaware	(15)
EDC Australia Ltd.	Delaware	(1)
EDC Ecuador Ltd.	Delaware	(1)
Noble Energy Ecuador Ltd.	Cayman Islands	(13)
EDC Portugal Ltd.	Delaware	(1)
Energy Development Corporation (Argentina), Inc.	Delaware	(1)
Energy Development Corporation (China), Inc.	Delaware	(1)

Energy Development Corporation (HIPS), Inc.	Delaware	(1)
Gasdel Pipeline System Incorporated	New Jersey	(1)
HGC, Inc.	Delaware	(1)
Producers Service, Inc.	New Jersey	(1)
EDC (UK) Limited	Delaware	(1)
EDC (Denmark) Inc.	Delaware	(11)
Noble Energy (Europe) Limited	United Kingdom	(11)
Noble Energy (ISE) Limited	United Kingdom	(12)
Noble Energy (Oilex) Limited	United Kingdom	(12)
Brabant Oil Limited	United Kingdom	(12)

REFERENCES:

(1) 100% directly owned by Noble Energy, Inc. (Registrant)
(2) 100% directly owned by Noble Energy Marketing, Inc.
(3) 100% directly owned by Samedan of North Africa, Inc.
(4) 100% directly owned by Noble Energy International Ltd.
(5) 50% directly owned by Samedan of North Africa, Inc.
(6) 100% directly owned by Atlantic Methanol Capital Company
(7) 50% directly owned by Samedan Methanol
(8) 90% directly owned by Atlantic Methanol Associates LLC
(9) 35% directly owned by Noble Energy International Ltd.
(10) 80% directly owned by Alba Associates LLC
(11) 100% directly owned by EDC (UK) Limited
(12) 100% directly owned by Noble Energy (Europe) Limited
(13) 100% directly owned by EDC Ecuador Ltd.
(14) 47.059% directly owned by Noble Energy Mediterranean Ltd.
(15) 1% General Partnership Interest by Noble Energy, Inc. (Registrant); 99% Limited Partnership Interest by Noble Energy, LLC

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

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

We consent to the incorporation by reference in the registration statements (File Nos. 333-18929 and 333-82953) on Form S-3 and the registration statements (File Nos. 333-108162, 333-39299, 33-32692, 2-66654, 33-54084, 333-118976, and 333-118977) on Form S-8 of Noble Energy, Inc. of our reports dated March 11, 2005 with respect to the consolidated balance sheets of Noble Energy, Inc. as of December 31, 2004 and 2003 and the related consolidated statements of operations, shareholders' equity and other comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2004, management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2004 and the effectiveness of internal control over financial reporting as of December 31, 2004, which reports appear in the Form 10-K of Noble Energy, Inc.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations.

KPMG LLP

Houston, Texas
March 11, 2005

EXHIBIT 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements (Form S-3 Nos. 333-82953 and 333-18929, Form S-8 Nos. 333-108162, 333-39299, 33-54084, 33-32692, 2-66654, 333-118976, and 333-118977) of Noble Energy, Inc. of our report dated January 28, 2004, with respect to the financial statements of Atlantic Methanol Production Company, LLC included in this Annual Report (Form 10-K) for the year ended December 31, 2004.

/s/ Ernst & Young LLP

March 11, 2005
Dallas, Texas

Exhibit 23.3

Consent of Independent Registered Public Accounting Firm

We hereby consent to the incorporation by reference in the Registration Statements (Form S-3 Nos. 333-82953 and 333-18929, Form S-8 Nos. 333-108162, 333-39299, 33-54084, 33-32692, 2-66654, 333-118976, and 333-118977) of Noble Energy, Inc. of our report dated January 18, 2005, with respect to the financial statements of Atlantic Methanol Production Company, LLC included in this Annual Report on Form 10-K for the year ended December 31, 2004.

/s/ UHY Mann Frankfort Stein & Lipp, CPA's, LLP

March 11, 2005
Houston, Texas

EXHIBIT 31.1

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 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 report;

3. Based on my knowledge, the financial statements, and other financial information included in this 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 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-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, 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 report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, 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 and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 14, 2005

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

EXHIBIT 31.2

CERTIFICATION

I, Chris Tong, certify that:

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

2. Based on my knowledge, this 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 report;

3. Based on my knowledge, the financial statements, and other financial information included in this 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 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-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, 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 report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, 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 and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 14, 2005

/s/ CHRIS TONG
CHRIS TONG
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. SECTION 1350)

In connection with the accompanying Annual Report of Noble Energy, Inc. (the "Company") on Form 10-K for the period ended December 31, 2004 (the "Report"), I, Charles D. Davidson, Chief Executive Officer of the Company, hereby certify that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 14, 2005

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

EXHIBIT 32.2

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. SECTION 1350)

In connection with the accompanying Annual Report of Noble Energy, Inc. (the "Company") on Form 10-K for the period ended December 31, 2004 (the "Report"), I, Chris Tong, Chief Financial Officer of the Company, hereby certify that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 14, 2005

/s/ CHRIS TONG
CHRIS TONG
Chief Financial Officer