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, 2005

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 (*Address of principal executive offices*)	77067 (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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☒ Yes ☐ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☐ Yes ☒ No

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 a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one): Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

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

Aggregate market value of Common Stock held by nonaffiliates as of June 30, 2005: $6,318,847,117. Number of shares of Common Stock outstanding as of February 14, 2006: 176,045,777.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2006 Annual Meeting of Stockholders to be held on April 25, 2006, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2005, are incorporated by reference into Part III.

TABLE OF CONTENTS

PART I

PART II

PART III

PART IV

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 1A. Risk Factors – Disclosure Regarding Forward-Looking Statements" of this Form 10-K.

General

Noble Energy, Inc. (the "Company" or "Noble Energy") is a Delaware corporation, formed in 1969, that has been publicly traded on the New York Stock Exchange ("NYSE") since 1980. Noble Energy is an independent energy company that has been engaged, directly or through its subsidiaries, in the exploration, development, production and marketing of crude oil and natural gas since 1932. In this report, unless otherwise indicated or the context otherwise requires, the "Company" or the "Registrant" refers to Noble Energy and its subsidiaries. Exploration activities include geophysical and geological evaluation and exploratory drilling on properties for which the Company has exploration rights. Noble Energy operates throughout major basins in the United States including Colorado's Wattenberg field, the Mid-continent region of western Oklahoma and the Texas Panhandle, the San Juan basin in New Mexico, the Gulf Coast and the Gulf of Mexico. Noble Energy also operates internationally, in Equatorial Guinea, the Mediterranean Sea, Ecuador, the North Sea, China, Argentina and Suriname. 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 in Ecuador.

On May 16, 2005, Noble Energy completed a merger (the "Patina Merger") with Patina Oil & Gas Corporation ("Patina"). Noble Energy, through its subsidiary Noble Energy Production, Inc., acquired the common stock of Patina for a total purchase price of approximately $4.9 billion, which was comprised primarily of cash and Noble Energy common stock, plus liabilities assumed. Patina was an independent energy company engaged in the acquisition and development of crude oil and natural gas properties within the continental United States. Patina's properties and crude oil and natural gas reserves are principally located in relatively long-lived fields with established production histories. The properties are primarily concentrated in the Wattenberg field of Colorado's Denver-Julesburg ("D-J") basin, the Mid-continent region of western Oklahoma and the Texas Panhandle, and the San Juan basin in New Mexico. See "Item 8. Financial Statements and Supplementary Data – Note 3 – Merger with Patina Oil & Gas Corporation."

Throughout this report, all share and per share data except par value have been adjusted to reflect the effect of the Company's two-for-one stock split, effected in the form of a stock dividend distributed on September 14, 2005 to shareholders of record as of August 31, 2005.

Strategy

Noble Energy is a worldwide producer of crude oil and natural gas. The Company's strategy is to achieve growth in earnings and cash flow through the development of a high quality portfolio of producing assets that is balanced between domestic and international projects. The Patina Merger allowed Noble Energy to achieve a strategic objective of enhancing its U.S. asset portfolio and has resulted in a company with assets and capabilities that include growing U.S. basins, coupled with a significant portfolio of international properties. After the Patina Merger, Noble Energy has approximately 36% greater production than 2004 with a reserve base that is balanced between domestic and foreign sources. In addition, the Company has been reducing its investment in the Gulf of Mexico's conventional shallow shelf and shifting its domestic offshore exploration focus to Gulf of Mexico deepwater areas. Noble Energy is now a larger, more diversified company with greater opportunities for both domestic and international growth through high upside exploration drilling as well as lower risk exploitation projects.

Current Developments

Pending Purchase of U.S. Exploration Holdings, Inc. – In February 2006, Noble Energy announced that it had agreed to purchase U.S. Exploration Holdings, Inc. ("U.S. Exploration"), a privately held corporation located in Billings, Montana, for $411.0 million. The acquisition will expand Noble Energy's operations in its core Wattenberg field, where the Company currently owns 218,000 net acres. Proved reserves of U.S. Exploration are estimated to be 248 billion cubic feet equivalent (Bcfe), of which 41% are proved developed and 55% are natural gas.

U.S. Exploration's reserves and production are located on approximately 65,000 net acres in the D-J basin's Wattenberg field. The majority of the acreage operated by U.S. Exploration lies within the scope of amendments to Colorado Oil and Gas Conservation Commission Rule 318A, which allow for increased density drilling in the field to 20-acre spacing. U.S. Exploration currently owns interests in 512 active wells. Capital spending on the U.S. Exploration properties will be focused on accelerating production and reserve development. In 2006, capital expenditures are expected to be approximately $100 million.

Subject to customary conditions, the transaction is scheduled to close on or before March 29, 2006. Upon closing, Noble Energy will pay $411.0 million in cash for the common stock of U.S. Exploration. Prior to closing, U.S. Exploration will retire all company debt, terminate its commodity hedges and make all severance payments.

Noble Energy has executed hedges on its own production volumes from March 2006 through 2010 that are equivalent to just over 50% of U.S. Exploration's expected volumes. The hedges are in the form of collars. The average floors on the natural gas hedges and crude oil hedges are $6.23 per MMbtu and $58.74 per Bbl. The average ceilings on the natural gas hedges and crude oil hedges are $9.17 MMbtu and $72.52 per Bbl. The natural gas hedges are priced at the CIG index and thereby include basis differentials to Henry Hub.

Crude Oil and Natural Gas Operations

For more information regarding Noble Energy's crude oil and natural gas properties, see "Item 2. Properties – Crude Oil and Natural Gas Properties" of this Form 10-K.

Exploration and Development Activities

North America

Noble Energy has been engaged directly or through its subsidiaries in exploration, exploitation and development activities onshore North America since 1932 and in the Gulf of Mexico since 1968. The Patina Merger significantly increased the breadth of the Company's onshore operations. The Company's onshore portfolio at December 31, 2005 included 1,267,048 gross developed acres and 812,750 gross undeveloped acres, of which 642,035 gross developed acres and 500,423 gross undeveloped acres were acquired in the Patina Merger. Onshore production was derived from 10,410 gross wells (7,641 net wells). In the Gulf of Mexico, Noble Energy holds interests in 278 blocks. At December 31, 2005 offshore production was derived from 343 gross wells (188 net wells).

International

Equatorial Guinea – Noble Energy began its investment in the Alba field (34% working interest in one block) offshore Equatorial Guinea in the early 1990's. Natural gas production from the Alba field is sold to a methanol plant on Bioko Island under a contract that runs through 2026. The methanol plant is owned by Atlantic Methanol Production Company, LLC ("AMPCO"), in which the Company has a 45% interest. AMPCO markets the methanol in Europe and the U.S. Natural gas production is also sold to a liquid petroleum gas ("LPG") plant, in which the Company has a 28% interest. Noble Energy's share of condensate produced in the Alba field and from the LPG plant is being sold under a short-term contract at market-based prices. The Company has entered into an additional natural gas sales contract, which runs through 2023, with an unaffiliated liquefied natural gas ("LNG") plant, which is currently under construction. The LNG plant is expected to begin production in 2008. Noble Energy has expanded its activities in Equatorial Guinea with exploration activities in Blocks "O" and "I" (45% and 40% working interest, respectively) on which it is the technical operator.

Israel – Noble Energy has been operating in the Mediterranean Sea, offshore Israel, since 1998. The Company has a 47% working interest under an exploration agreement covering three licenses and two leases and is the operator. Natural gas is produced from the Mari-B field, the first offshore natural gas production facility in the State of Israel. Natural gas sales began in 2004 and have been increasing as a purchaser of the Company's production, the Israel Electric Corporation Limited, developed its capacity to take natural gas at its Eshkol power station. Additionally, Noble Energy commenced sales of natural gas to the Bazan Oil Refinery located in Ashdod in the fourth quarter of 2005. Noble Energy has also contracted to sell Mari-B natural gas to other industrial users including a desalinization plant and a paper mill. Sales to these facilities are currently expected to begin in 2007.

North Sea – Noble Energy has been engaged in exploration and development of crude oil and natural gas properties in the North Sea (the Netherlands and the United Kingdom) since 1996. The Company has working interests in 17 licenses with working interests ranging from 6.5% to 100%. Noble Energy is the operator of three blocks.

Ecuador – Noble Energy has been operating in Ecuador since 1996. The Company is currently utilizing the natural gas from the Amistad field (offshore Ecuador) to generate electricity through its 100%-owned natural gas-fired power plant, located near the city of Machala. The Machala power plant, which began operating in 2002, is a single cycle generator with a daily capacity of 130 MW from twin turbines. It is the only natural gas-fired commercial power generator in Ecuador and currently one of the lowest cost producers of thermal power in the country.

China – Noble Energy has been engaged in exploration and development activities in China since 1996. The Company developed the Cheng Dao Xi oil field in Bohai Bay and production began in 2003. Noble Energy's share of crude oil production is sold into the domestic Chinese market pursuant to a long-term contract at market-based prices.

Argentina – Noble Energy has had a presence in Argentina since 1996 and is currently participating in an expansion of the El Tordillo field in the San Jorge basin.

Suriname – In 2005, Noble Energy entered into a participation agreement on Block 30 in offshore Suriname, a country located on the northern coast of South America. A seismic program is currently underway.

Production Activities

Revenues from sales of crude oil and natural gas and from gathering, marketing and processing have accounted for 90% or more of consolidated revenues for each of the last three fiscal years.

At December 31, 2005, Noble Energy operated properties accounting for approximately 59% of the Company's total production. Being the operator of a property allows the Company to manage production and to control timing and amounts of operating expenses and capital expenditures.

Acquisition and Disposition Activities

The Company maintains an ongoing portfolio optimization program. The Company may engage in acquisitions of additional crude oil or natural gas properties, additional interests in its existing assets or entities owning crude oil and natural gas properties or related assets. The Company may also divest non-core assets in order to maintain a balanced portfolio with high-quality, core properties.

On May 16, 2005 Noble Energy completed the Patina Merger. Values preliminarily allocated to proved and unproved properties acquired were $2.6 billion and $1.1 billion, respectively. Patina's long-lived crude oil and natural gas reserves provide a significant inventory of low-risk opportunities that balance Noble Energy's portfolio. The preliminary allocation of the purchase price included $874.8 million of goodwill.

During 2005, 2004 and 2003, the Company spent approximately $0.6 million, $85.8 million and $1.3 million, respectively, on the acquisition of proved crude oil and natural gas properties (excluding Patina properties), and, during 2005, 2004 and 2003, spent approximately $16.9 million, $44.7 million, and $10.2 million, respectively, on acquisitions of unproved properties (excluding Patina properties). These properties were acquired through various offshore lease sales, domestic onshore lease acquisitions and international concession negotiations.

During 2004, the Company completed a significant asset disposition program that had begun in 2003. The asset disposition program included five domestic property packages, representing estimated reserves of 24.2 MMBoe. The sales price for the five packages of properties totaled $130 million.

2006 Budget

The Company has budgeted capital expenditures of approximately $1.26 billion for 2006. Approximately 23% of the 2006 capital budget has been allocated to exploration opportunities and 77% has been allocated to production, development and other projects. Domestic spending is budgeted for $860 million (68% of the 2006 capital budget), international expenditures are budgeted for $380 million (30%) and corporate expenditures are budgeted for $20 million (2%). The 2006 budget does not include the impact of possible asset purchases, including the previously announced pending purchase of U.S. Exploration as well as anticipated development costs associated with U.S. Exploration.

Marketing Activities

Marketing Stranded Gas – With major projects in Equatorial Guinea, Ecuador and Israel, Noble Energy has substantial natural gas reserves that, until recently, had no market. In Equatorial Guinea, Noble Energy and its partners constructed an LPG plant and a low-cost methanol plant. The recently completed Phase 2A and 2B expansion projects have increased gross LPG and condensate production. In Ecuador, Noble Energy's Amistad field had no market until the Company constructed a natural gas-fired power plant near Machala. The Machala power plant is one of the lowest cost thermal power producers in Ecuador. Offshore Israel, Noble Energy discovered natural gas in the Mari-B field. While Israel has not traditionally been a consumer of natural gas and has no other significant domestic hydrocarbon sources, Noble Energy has negotiated contracts to provide natural gas to the Israel Electric Corporation Limited, Bazan Oil Refinery and other industrial users.

Natural Gas Marketing – Natural gas produced by the Company in the United States is sold under short-term or long-term contracts at market-based prices. In Equatorial Guinea and Israel, Noble Energy sells natural gas to end-users under long-term contracts at negotiated prices. At December 31, 2005, approximately 28% of Noble Energy's natural gas sales were made pursuant to long-term contracts.

Crude Oil and Condensate Marketing – Crude oil and condensate produced by the Company in the United States and foreign locations is generally sold under short-term contracts at market-based prices adjusted for location and quality. Crude oil and condensate are distributed through pipelines and by trucks or tankers to gatherers, transportation companies and end-users.

Noble Energy Marketing, Inc. – Noble Energy markets portions of its domestic natural gas production through Noble Energy Marketing, Inc. ("NEMI"), a wholly-owned subsidiary. 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. NEMI also engages in the purchase and sale of third-party crude oil and natural gas production. Such third-party 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 owns no interest. Noble Energy has a long-term natural gas sales contract with NEMI, whereby the Company receives 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 55% of its domestic natural gas production to NEMI in 2005.

Significant Purchasers – Glencore Energy U.K., Ltd. ("Glencore") was the largest single non-affiliated purchaser of Noble Energy's 2005 production. Glencore was a purchaser of the Company's share of condensate from the Alba field in Equatorial Guinea. Sales to Glencore accounted for approximately 24% of 2005 crude oil sales, or approximately 11% of 2005 total oil and gas sales and royalties. No other single non-affiliated purchaser accounted for 10% or more of Noble Energy's 2005 oil and gas sales and royalties. The Company believes that the loss of any one purchaser would not have a material effect on the Company's financial position or results of operations since there are numerous potential purchasers of the Company's production.

Hedging Activities

Commodity prices remained volatile during 2005. Prices for crude oil and natural gas are affected by a variety of factors that are beyond the Company's control. Noble Energy has used derivative instruments, and expects to do so in the future, to achieve a more predictable cash flow by reducing its exposure to commodity price fluctuations. For additional information, see "Item 1A. Risk Factors – *Hedging transactions may limit our potential gains*", "Item 7A. Quantitative and Qualitative Disclosures About Market Risk", and "Item 8. Financial Statements and Supplementary Data – Note 12 – Derivative Instruments and Hedging Activities."

Regulations

Governmental Regulation – 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.

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. We must take into account the cost of complying with environmental regulations in planning, designing, drilling, operating and abandoning wells. In most instances, the regulatory requirements relate to the handling and disposal of drilling and production waste products, water and air pollution control procedures, and the remediation of petroleum-product contamination. Under state and federal laws, we could be required to remove or remediate previously disposed wastes, including wastes disposed of or released by us or prior owners or operators in accordance with current laws or otherwise, to suspend or cease operations in contaminated areas, or to perform remedial well plugging operations or cleanups to prevent future contamination. The Environmental Protection Agency and various state agencies have limited the disposal options for hazardous and non-hazardous wastes. The owner and operator of a site, and persons that treated, disposed of or arranged for the disposal of hazardous substances found at a site, may be liable, without regard to fault or the legality of the original conduct, for the release of a hazardous substance into the environment. The Environmental Protection Agency, state environmental agencies and, in some cases, third parties are authorized to take actions in response to threats to human health or the environment and to seek to recover from responsible classes of persons the costs of such action. Furthermore, certain wastes generated by our crude oil and natural gas operations that are currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes and, therefore, be subject to considerably more rigorous and costly operating and disposal requirements. See "Item 1A. Risk Factors – *We are subject to various governmental regulations and environmental risks that may cause us to incur substantial costs*."

Federal and state occupational safety and health laws require us to organize information about hazardous materials used, released or produced in our operations. Certain portions of this information must be provided to employees, state and local governmental authorities and local citizens. We are also subject to the requirements and reporting set forth in federal workplace standards.

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 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 maintains various types of insurance coverages as are customary in the industry that include directors and officers liability, general liability, well control, pollution, acts of terrorism, 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 $1.0 million of its general liability coverage.

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

Competition

The crude oil and natural gas industry is highly competitive. The Company encounters competition from other crude oil and natural gas companies in all areas of operations, including the acquisition of seismic and lease rights on crude oil and natural gas properties and for the labor and equipment required for exploration and development of those properties. The Company's competitors include major integrated crude oil and natural gas companies and numerous independent crude oil and natural gas companies, individuals and drilling and income programs. Many of the Company's competitors are large, well established companies. Such companies may be able to pay more for seismic and lease rights on crude oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. The Company's ability to acquire additional properties and to discover reserves in the future will be dependent upon its ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. See "Item 1A. Risk Factors – *We face significant competition and many of our competitors have resources in excess of our available resources*."

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, development 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."

Employees

The total number of employees of the Company increased during the year from 559 at December 31, 2004 to 1,171 at December 31, 2005, primarily due to the Patina Merger. The 2005 year-end employee count includes 108 foreign nationals working as employees of the Company in Equatorial Guinea, the United Kingdom, Ecuador and Israel.

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 Securities and Exchange Commission ("SEC").

Also posted on the Company's website, and available in print upon request by 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 (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 2005, 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.

Item 1A. Risk Factors.

Crude oil and natural gas prices are volatile and a substantial reduction in these prices could adversely affect our results and the price of our common stock.

Our revenues, operating results and future rate of growth depend highly upon the prices we receive for our crude oil and natural gas production. Historically, the markets for crude oil and natural gas have been volatile and are likely to continue to be volatile in the future. The markets and prices for crude oil and natural gas depend on factors beyond our control. These factors include demand for crude oil and natural gas, which fluctuates with changes in market and economic conditions and other factors, including:

- worldwide and domestic supplies of crude oil and natural gas;
- actions taken by foreign oil and gas producing nations;
- political conditions and events (including instability or armed conflict) in crude oil-producing or natural gas-producing regions;
- the level of global crude oil and natural gas inventories;
- the price and level of foreign imports;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the availability of pipeline capacity;
- the availability of crude oil transportation and refining capacity;
- weather conditions;
- domestic and foreign governmental regulations and taxes; and
- the overall economic environment.

Significant declines in crude oil and natural gas prices for an extended period may have the following effects on our business:

- limiting our financial condition, liquidity, ability to finance planned capital expenditures and results of operations;
- reducing the amount of crude oil and natural gas that we can produce economically;
- causing us to delay or postpone some of our capital projects;
- reducing our revenues, operating income and cash flow;
- reducing the carrying value of our crude oil and natural gas properties; or
- limiting our access to sources of capital, such as equity and long-term debt.

Failure to fund continued capital expenditures could adversely affect our properties.

If revenues substantially decrease as a result of lower crude oil and natural gas prices or otherwise, we may have limited ability to spend the capital necessary to replace our reserves or to maintain production at current levels, resulting in a decrease in production over time. We expect to continue to make capital expenditures for the acquisition, exploration and development of crude oil and natural gas reserves. Historically, we have financed these expenditures primarily with cash flow from operations and proceeds from debt and equity financings. However, if cash flow from operations is not sufficient to satisfy capital expenditure requirements, we cannot provide assurance that we will be able to obtain additional debt or equity financing or other sources of capital to meet these requirements. If we are not able to fund our capital expenditures, then interests in some properties might be reduced or forfeited.

We may be unable to make attractive acquisitions or integrate acquired businesses and/or assets, and any inability to do so may disrupt our business.

One aspect of our business strategy calls for acquisitions of businesses and assets that complement or expand our current business. We cannot provide assurance that we will be able to identify attractive acquisition opportunities. Even if we do identify attractive candidates, we cannot provide assurance that we will be able to complete the acquisition of them or do so on commercially acceptable terms. Additionally, if we acquire another business, we could have difficulty integrating its operations, systems, management and other personnel and technology with our own. These difficulties could disrupt ongoing business, distract management and employees, increase expenses and adversely affect results of operations. Even if these difficulties could be overcome, we cannot provide assurance that the anticipated benefits of any acquisition would be realized.

Estimates of crude oil and natural gas reserves are not precise.

There are numerous uncertainties inherent in estimating crude oil and natural gas reserves and their value, including many factors that are beyond our control. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. The estimates depend on a number of factors and assumptions that may vary considerably from actual results, including:

- historical production from the area compared with production from other areas;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future crude oil and natural gas prices;
- future operating costs;
- severance and excise taxes;
- development costs; and
- workover and remedial costs.

For these reasons, estimates of the economically recoverable quantities of crude oil and natural gas attributable to any particular group of properties, classifications of those reserves based on risk of recovery and estimates of the future net cash flows expected from them prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, reserve estimates may be subject to upward or downward adjustment, and actual production, revenue and expenditures with respect to our reserves likely will vary, possibly materially, from estimates.

Additionally, because most of our reserve estimates are calculated using volumetric analysis, those estimates are less reliable than estimates based on a lengthy production history. Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure. In addition, realization or recognition of proved undeveloped reserves will depend on our development schedule and plans. Lack of certainty with respect to development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved.

Exploration, development and production risks and natural disasters could result in liability exposure or the loss of production and revenues.

Our operations are subject to hazards and risks inherent in the drilling, production and transportation of crude oil and natural gas, including:

- pipeline ruptures and spills;
- fires;
- explosions, blowouts and cratering;
- formations with abnormal pressures;
- equipment malfunctions;
- hurricanes; and
- other natural disasters.

Any of these can result in loss of hydrocarbons, environmental pollution and other damage to our properties or the properties of others.

Exploration and development drilling may not result in commercially productive reserves.

We do not always encounter commercially productive reservoirs through our drilling operations. The wells we drill or participate in may not be productive and we may not recover all or any portion of our investment in those wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that crude oil or natural gas is present or may be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Our efforts will be unprofitable if we drill dry holes or wells that are productive but do not produce enough reserves to return a profit after drilling, operating and other costs. Further, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental requirements; and
- increases in the cost of, or shortages or delays in the availability of, drilling rigs and equipment.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and other oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs of rigs, equipment and supplies are substantially greater and their availability may be limited. As a result of increasing levels of exploration and production in response to strong prices of crude oil and natural gas, the demand for oilfield services has risen and the costs of these services are increasing, while the quality of these services may suffer. Additionally, these services may not be available on commercially reasonable terms.

We may not have enough insurance to cover all of the risks we face, which could result in significant financial exposure.

As protection against operating hazards, we maintain insurance coverage against some, but not all, potential losses, including the loss of wells, blowouts, pipeline leakage or other damage, certain costs of pollution control and physical damages on certain assets. Our insurance coverage includes crude oil and natural gas properties and construction insurance, marine cargo insurance and third party and comprehensive general liability insurance. Except for our operations in Israel and Equatorial Guinea, we do not carry business interruption insurance.

We may not have sufficient coverage for some of the risks we face, either because insurance is not available on commercially reasonable terms or because of single event limitations by our insurer. If an event occurs that is not covered, or not fully covered, by insurance, it could harm our financial condition, results of operations and cash flows. In addition, we cannot fully insure against pollution and environmental risks.

We face significant competition and many of our competitors have resources in excess of our available resources.

We operate in the highly competitive areas of crude oil and natural gas exploration, exploitation, acquisition and production. We face intense competition from a large number of independent, technology-driven companies as well as both major and other independent crude oil and natural gas companies in a number of areas such as:

- seeking to acquire desirable producing properties or new leases for future exploration;
- marketing our crude oil and natural gas production; and
- seeking to acquire the equipment and expertise necessary to operate and develop properties.

Many of our competitors have financial and other resources substantially in excess of those available to us. This highly competitive environment could have an adverse impact on our business.

We are subject to various governmental regulations and environmental risks that may cause us to incur substantial costs.

From time to time, in varying degrees, political developments and federal and state laws and regulations affect our operations. In particular, price controls, taxes and other laws relating to the crude oil and natural gas industry, changes in these laws and changes in administrative regulations have affected and in the future could affect crude oil and natural gas production, operations and economics. We cannot predict how agencies or courts will interpret existing laws and regulations or the effect of these adoptions and interpretations may have on our business or financial condition.

Our business is subject to laws and regulations promulgated by international, federal, state and local authorities, relating to the exploration for, and the development, production and marketing of, crude oil and natural gas, as well as safety matters. Legal requirements are frequently changed and subject to interpretation and we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. We may be required to make significant expenditures to comply with governmental laws and regulations.

Our operations are subject to complex international, federal, state and local environmental laws and regulations, including the Comprehensive Environmental Response, Compensation and Liability Act, as amended, the Resource Conservation and Recovery Act, as amended, the Oil Pollution Act of 1990 and the Clean Water Act. Environmental laws and regulations change frequently, and the implementation of new, or the modification of existing laws or regulations could harm us. The discharge of natural gas, crude oil, or other pollutants into the air, soil or water may give rise to significant liabilities on our part to the government and third parties and may require us to incur substantial costs of remediation.

Our international operations may be adversely affected by economic and political developments.

We have significant international crude oil and natural gas operations. As a result, those operations may be adversely affected by political and economic developments, including war, terrorism and other instability, expropriation or nationalization, royalty and tax increases, and other laws or policies in these countries, as well as United States policies affecting trade, taxation, and investment in other countries.

Significant capital expenditures are required to replace our reserves.

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, our revolving bank credit facility and debt and equity issuances. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of crude oil and natural gas, and our success in developing and producing new reserves. If revenue were to decrease as a result of lower crude oil and natural gas prices or decreased production, and our access to capital were limited, we would have a reduced ability to replace our reserves. If our cash flow from operations is not sufficient to meet our obligations and fund our capital expenditure budget, we may not be able to access debt, equity or other methods of financing on an economic basis to meet these requirements.

Our level of indebtedness may limit our financial flexibility.

As of December 31, 2005, we had long-term indebtedness of $2.035 billion, with $1.28 billion drawn under our bank credit facility. Our long-term indebtedness represented 40% of our total book capitalization at December 31, 2005.

Our level of indebtedness affects our operations in several ways, including the following:

- a portion of our cash flows from operating activities must be used to service our indebtedness and is not available for other purposes;
- we may be at a competitive disadvantage as compared to similar companies that have less debt;
- the covenants contained in the agreements governing our outstanding indebtedness and future indebtedness may limit our ability to borrow additional funds, pay dividends and make certain investments and may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes may have higher costs and more restrictive covenants;
- changes in the credit ratings of our debt may negatively affect the cost, terms, conditions and availability of future financing, and lower ratings will increase the interest rate and fees we pay on our revolving credit facility; and
- we may be more vulnerable to general adverse economic and industry conditions.

We may incur additional debt in order to fund our exploration and development activities. A higher level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and reduce our level of indebtedness depends on future performance. General economic conditions, crude oil and natural gas prices and financial, business and other factors will affect our operations and our future performance. Many of these factors are beyond our control and we may not be able to generate sufficient cash flow to pay the interest on our debt, and future working capital, borrowings and equity financing may not be available to pay or refinance such debt.

Hedging transactions may limit our potential gains.

In order to manage our exposure to price risks in the marketing of our crude oil and natural gas, we enter into crude oil and natural gas price hedging arrangements with respect to a portion of our expected production. Our hedges, consisting of a series of contracts, are limited in duration, usually for periods of one to four years. However, in connection with acquisitions, sometimes our hedges are for longer periods. While intended to reduce the effects of volatile crude oil and natural gas prices, such transactions may limit our potential gains if crude oil and natural gas prices rise over the price established by the arrangements. In trying to manage our exposure to price risk, we may end up hedging too much or too little, depending upon how our crude oil or natural gas volumes and our production mix fluctuate in the future. In addition, hedging transactions may expose us to the risk of financial loss in certain circumstances, including instances in which our production is less than expected; there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement; the counterparties to our future contracts fail to perform under the contracts; or a sudden unexpected event materially impacts crude oil or natural gas prices. We cannot assure you that our hedging transactions will reduce the risk or minimize the effect of any decline in crude oil or natural gas prices.

Provisions in our Certificate of Incorporation, Stockholder Rights Plan and Delaware law may inhibit a takeover of us.

Under our Certificate of Incorporation, our Board of Directors is authorized to issue shares of our common or preferred stock without approval of our stockholders. Issuance of these shares could make it more difficult to acquire us without the approval of our Board of Directors as more shares would have to be acquired to gain control. We also have a stockholder rights plan, commonly known as a "poison pill," that entitles our stockholders to acquire additional shares of our company, or a potential acquirer of our company, at a substantial discount from market value in the event of an attempted takeover without the approval of our Board. Finally, Delaware law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. These provisions may deter hostile takeover attempts that could result in an acquisition of us that would have been financially beneficial to our stockholders.

Disclosure Regarding Forward-Looking Statements

This annual report on Form 10-K and the documents incorporated by reference in this report contain forward-looking statements within the meaning of the federal securities laws. Forward-looking statements give our current expectations or forecasts of future events. These forward-looking statements include, among others, the following:

- our growth strategies;
- our ability to successfully and economically explore for and develop crude oil and natural gas resources;
- anticipated trends in our business;
- our future results of operations;
- our liquidity and ability to finance our exploration and development activities;
- market conditions in the oil and gas industry;
- our ability to make and integrate acquisitions; and
- the impact of governmental regulation.

Forward-looking statements are typically identified by use of terms such as "may," "will," "expect," "anticipate," "estimate" and similar words, although some forward-looking statements may be expressed differently. These forward-looking statements are made based upon management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements. You should consider carefully the statements under Item 1A. Risk Factors and other sections of this report, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

Offices

The principal corporate office of Noble Energy is located at 100 Glenborough Drive, Suite 100, Houston, Texas 77067-3610. The Company also maintains offices for domestic and international operations at the Houston location. The Company maintains additional offices in Ardmore, Oklahoma and Denver, Colorado and in China, Ecuador, Equatorial Guinea, Israel and the United Kingdom.

Proved Reserves

As of December 31, 2005, Noble Energy had estimated proved reserves of 3,091 Bcf of natural gas and 291 MMBbls of crude oil. On a combined basis, these proved reserves were equivalent to 807 MMBoe, of which 53% were located in the U.S. and 47% were located internationally. At December 31, 2005, 75% of reserves were proved developed reserves. During 2005, the Company's U.S. reserves increased by 200%. Over 85% of domestic reserve additions were due to the Patina Merger. At the merger date (May 16, 2005), Patina's proved reserves were approximately 271 MMBoe.

The following table sets forth estimates of Noble Energy's proved natural gas and crude oil reserves as of December 31, 2005:

	As of December 31, 2005		
	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
U.S.			
Natural gas (Bcf)	1,279	362	1,641
Crude oil (MMBbls)	114	38	152
Total U.S. (MMBoe)	328	98	426
International			
Natural gas (Bcf)	923	527	1,450
Crude oil (MMBbls)	124	15	139
Total International (MMBoe)	278	103	381
Worldwide			
Natural gas (Bcf)	2,202	889	3,091
Crude oil (MMBbls)	238	53	291
Total Worldwide (MMBoe)	606	201	807

For additional information regarding estimates of crude oil and natural gas reserves, including estimates of proved and proved developed reserves, the standardized measure of discounted future net cash flows, and the changes in discounted future net cash flows, see "Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information." See also "Item 7. Critical Accounting Policies and Estimates – Reserves."

Company engineers in the Houston and Denver offices perform all reserve estimates for the Company's different geographical regions. These reserve estimates are reviewed and approved by appropriate senior engineering staff and Division management with final approval by the Senior Vice President with responsibility for corporate reserves. During 2005, Noble Energy retained Netherland, Sewell & Associates, Inc. ("NSAI"), independent third-party reserve engineers, to perform a reserve audit of proved reserves. The reserve audit included a detailed review of eleven of the Company's major international, deepwater, and domestic properties, which covered approximately 72% of Noble Energy's total proved reserves. In 2004, Noble Energy also retained NSAI 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% of Noble Energy's total proved reserves. For 2003, Noble Energy retained NSAI to perform a reserve procedural audit of the Company's procedures and methods used to estimate proved reserves.

Since January 1, 2005, 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") of the U.S. Department of Energy. Noble Energy files Form 23, including reserve and other information, with the EIA.

Crude Oil and Natural Gas Properties

Noble Energy 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 has acquired exploration rights. Noble Energy's properties consist primarily of interests in developed and undeveloped crude oil and natural gas leases. The Company also owns natural gas and natural gas liquids ("NGL") processing plants and pipeline systems. At December 31, 2005, the Company had exploration, development and/or production operations in North America (U.S.), Equatorial Guinea, Israel, North Sea (the Netherlands and the United Kingdom), Ecuador, China, Argentina and Suriname.

North America – Noble Energy's North America operations accounted for 58% of 2005 company-wide production and 53% of total proved reserves at December 31, 2005. Domestic proved reserves are approximately 64% natural gas and 36% crude oil. During 2005, Noble Energy expanded its operations in the Rocky Mountain and Mid-continent regions with the Patina Merger. The Patina Merger provided Noble Energy with a multi-year inventory of exploitation and development opportunities. The following discussion includes activities related to Patina properties from the merger date (May 16, 2005) through December 31, 2005.

***Rocky Mountain Region* –** The Rocky Mountain region includes the D-J (Wattenberg field), San Juan, Wind River, and Piceance basins, as well as the Niobrara, Bowdoin and Siberia Ridge fields. The addition of Patina's assets, particularly in the Wattenberg field, combined with Noble Energy's operations in the Bowdoin field, the Niobrara trend, the Wind River basin and Piceance basin have created a new core operating area in the Rocky Mountains. The Company is currently operating 7 drilling rigs and 25 completion units.

Wattenberg Field – Noble Energy acquired working interests in the Wattenberg field through the Patina Merger. Wattenberg provides the Company with a substantial future project inventory. The Wattenberg field is located in the D-J basin of north central Colorado. One of the most attractive features of the field is the presence of multiple productive formations. In a section 4,500 feet thick, there may be up to eight potentially productive formations. Three of the formations, the Codell, Niobrara and J-Sand, are considered "blanket" zones in the area of the Company's holdings, while others, such as the D-Sand, Dakota and the shallower Shannon, Sussex and Parkman, are more localized.

Drilling in Wattenberg field is considered low risk from the perspective of finding crude oil and natural gas reserves, with 100% of the wells drilled in 2005 encountering sufficient quantities of reserves to be completed as economic producers. The Company's working interest at December 31, 2005 is approximately 94%. In May 1998, the COGCC adopted the "Greater Wattenberg Area Special Well Location Rule 318A" which allows all formations in the Wattenberg field to be drilled, produced and commingled from any or all of ten "potential drilling locations" on a 320-acre parcel. In December of 2005, the COGCC amended Rule 318A providing for an effective well density of one well per 20 acres in a designated portion of the Greater Wattenberg Area. The amendment applies only to the Niobrara, Codell and J-Sand formations and will become effective in March 2006.

In 2005, development expenditures in the Wattenberg field totaled $117.3 million. The Company's current field activities are focused primarily on the development of J-Sand and Codell reserves through drilling new wells or deepening within existing wellbores, refracing or trifracing existing Codell wells and refracing or recompleting the Niobrara formation within existing Codell wells. A refrac consists of the restimulation of a producing formation within an existing wellbore to enhance production and add incremental reserves. These projects and continued success with the production enhancement program allowed the Company to increase its production and to add proved reserves in 2005 in what is considered a mature field.

During 2005 the Company drilled 34 wells and deepened eight wells to the J-Sand formation in Wattenberg. At December 31, 2005, the Company had over 265 proven J-Sand drilling locations or deepening projects in inventory. The Company plans to drill or deepen approximately 42 wells to the J-Sand in 2006.

The Company performed 174 Codell refracs in Wattenberg field during 2005. At December 31, 2005, the Company had approximately 1,500 proven Codell refrac projects. The Company plans to perform approximately 235 Codell refrac projects in 2006.

The Company performed 28 Codell trifracs in Wattenberg field during 2005. The trifrac program, which is effectively a refrac of a refrac, has had encouraging results. The Company expects to perform approximately 132 trifracs in 2006. At December 31, 2005, the Company had approximately 455 proven Codell trifrac projects in inventory.

The Company performed 177 Niobrara refracs or recompletions in Wattenberg field during 2005. At December 31, 2005, the Company had approximately 1,050 proven Niobrara projects. The Company plans to perform approximately 300 Niobrara projects in 2006.

The Company also performed 24 Codell recompletions and drilled 84 Codell wells in the D-J basin in 2005. The Company had an additional 320 Codell/J-Sand/Sussex proven recompletion opportunities and over 1,070 Codell new drill opportunities at December 31, 2005. The Company plans to drill 172 Codell wells in 2006.

During 2005, numerous well workovers, reactivations, and commingling of zones were performed. These projects, combined with the new drills, deepenings and refracs, were an integral part of the 2005 Wattenberg development program. The Company estimates it had over 800 of these minor projects in inventory at year-end 2005.

At December 31, 2005, the Company had working interests in approximately 3,700 gross (3,500 net) producing oil and gas wells in the D-J basin. Daily production from this field averaged 9,525 Bbls per day of crude oil and 140,141 Mcf per day of natural gas for the period May 16, 2005 through December 31, 2005. The Company anticipates spending approximately $220.5 million in Wattenberg in 2006 or approximately 18% of budgeted capital.

San Juan Basin – The San Juan basin is located in northwestern New Mexico and southwestern Colorado. During 2005 Noble Energy completed 17 development wells, all of which were successful. The Company expects to drill 18 new wells and recomplete four others during 2006.

Niobrara Trend – The Niobrara trend is located in eastern Colorado. Drilling in Noble Energy's Niobrara trend project increased substantially during 2005. Noble Energy completed 213 development wells with a 91% success rate during 2005. The Company expects to drill 35 wells in 2006.

Bowdoin Field **–** The Bowdoin field is located in north central Montana. During 2005, Noble Energy drilled 39 development wells, all of which were successful. The Company expects to drill 25 new wells and recomplete 50 wells during 2006.

Piceance Basin – The Piceance basin in western Colorado is another rapidly growing area for Noble Energy. The Company drilled six development wells during 2005, all of which were successful. The Company expects to drill 24 wells during 2006.

Siberia Ridge Field – The Siberia Ridge field is located in south central Wyoming. During 2005, Noble Energy drilled six development wells, all of which were successful. The Company expects to drill three wells during 2006.

Wind River Basin – The Wind River basin is located in central Wyoming. During 2005, Noble Energy drilled three development wells, two of which were successful. The Company expects to drill 16 wells during 2006.

Acreage Agreement – In January 2006, Noble Energy entered into an acreage earning agreement with Teton Energy Corporation. Under the terms of the agreement, Noble Energy will earn a 75% working interest in approximately 184,000 acres in the D-J basin by drilling 20 wells on or before March 1, 2007. Upon completion of the first 20 wells, Noble Energy and Teton will split all costs associated with future drilling according to each party's working interest. The acreage included in this agreement is a potential eastward extension of the prolific Niobrara producing trend in Yuma County, Colorado.

Mid-continent Region – The Mid-continent region includes Illinois, Kansas, Oklahoma, and the Texas panhandle. The Patina Merger has made the Mid-continent region another core area for Noble Energy. The Company is currently operating 10 drilling rigs and 20 completion units.

Buffalo Wallow – A significant area of activity in the Mid-continent region is the Buffalo Wallow field located in the Texas panhandle. The primary producing horizons, which generally produce natural gas, are comprised of various intervals in the Granite Wash sequence at approximately 11,000 feet. The productive intervals include a series of stratigraphically trapped sands with an average gross interval of 700 feet. The field has historically been developed on 40-acre spacing. In late 2004, the Texas Railroad Commission approved down-spacing of the field to allow development on 20-acre locations. The Company drilled 64 development wells in the Buffalo Wallow field in 2005, all of which were successful. The Company plans to drill approximately 70 wells in 2006. The Company anticipates spending approximately $120.0 million in Buffalo Wallow in 2006 or approximately 10% of budgeted capital.

Billy Rose – The Billy Rose field is located in the Texas panhandle. During 2005, the Company drilled five development wells, all of which were successful. During 2006, the Company plans to drill 12 additional wells.

Central Oklahoma – During 2005, the Company drilled 55 wells, 51 of which were successful. The Company plans to drill 75 wells during 2006.

Illinois – In southern Illinois, the Company instituted a drilling program, drilling 36 development wells in 2005, 34 of which were successful. The Company plans to drill 50 wells in 2006.

Other – During 2005, the Company completed an additional 24 wells in the Mid-continent region including wells drilled in Kansas and other parts of Oklahoma.

Southern Region – The Southern region includes the Gulf Coast onshore, West and East Texas, Louisiana and the Gulf of Mexico. The Gulf Coast and deepwater Gulf of Mexico represent a core domestic operating area.

Deepwater – During 2005, the Company continued to focus on growth of its deepwater Gulf of Mexico business with several key development projects moving toward first production.

Viosca Knoll Block 917, 961, and 962 ("Swordfish"), a 2001 deepwater discovery, is located in approximately 4,500 feet of water. The Swordfish field consists of three wells with crude oil and natural gas pay in multiple, high quality reservoirs. Noble Energy has a 60% working interest in Swordfish and became operator for the project effective December 1, 2005. During 2005, the three subsea wells were tied back via dual flowlines to Kerr-McGee's Neptune spar in Viosca Knoll Block 826. Due to host construction delays, an active 2005 hurricane season, and numerous storm-related downstream service disruptions, Swordfish first production was delayed until the fourth quarter of 2005. First production was established with a production volume of approximately 8,500 Boepd, net to the Company.

Green Canyon Block 199 ("Lorien"), a 2003 deepwater discovery, is located in approximately 2,200 feet of water. Noble Energy is the operator of the development with a 60% working interest. The Lorien development was sanctioned in March 2005. During 2005, a development well was successfully drilled and both the discovery well and development well were completed. The Lorien field consists of two subsea wells. At year-end, installation of subsea infrastructure to tie the wells back to a nearby host was in progress. Host upgrade and final subsea construction will be completed in 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 recorded net reserves of 4.2 MMBoe in 2005 and expects to add proved reserves during 2006 based on production performance.

Green Canyon Block 768 ("Ticonderoga"), a 2004 deepwater discovery, is located in approximately 5,300 feet of water. Noble Energy holds a 50% non-operated position in the development. The Ticonderoga field is near Kerr-McGee's Constitution development in Green Canyon Block 680 and is a subsea tieback to the Constitution spar. During 2005, a development well was successfully drilled and both the discovery well and development well were completed. Ticonderoga achieved first production on February 16, 2006 and has achieved peak production volumes of approximately 8,750 Bopd and 6,600 Mcfpd, net to Noble Energy's 50% working interest.

At year-end, the Company began drilling its Redrock exploration prospect at Mississippi Canyon Block 204. The Mississippi Canyon 204 #1 well has a proposed total depth of 22,300 feet and is located in approximately 3,300 feet of water. The well will test the first of two Noble Energy operated exploration prospects planned for this area in 2006.

Noble Energy submitted successful high bids on eight (out of eight total bids submitted) deepwater lease blocks in the Central Gulf of Mexico Lease Sale 194 held in March 2005. The bids were all made at a 100% working interest and totaled $9.3 million.

In December 2005, Noble Energy and Samson Offshore Company ("Samson") entered into an exploration agreement covering interests in 37 deepwater leases held by Noble Energy in the Gulf of Mexico. Under the terms of the agreement, Samson acquired 25% of Noble Energy's working interest in the leases, a majority of which were 100% owned and operated by Noble Energy. Noble Energy and Samson plan to drill at least four exploratory wells through the end of 2008, the first of which is Mississippi Canyon 204 #1 which commenced at year-end 2005.

Hurricanes – The Gulf of Mexico experienced significant hurricane activity in 2004 and 2005. In September 2004, Hurricane Ivan moved through the Gulf of Mexico resulting in infrastructure damage at Main Pass 293/305/306. Clean-up and redevelopment activities began in 2005 and sales of production from the undamaged Main Pass platforms commenced third quarter 2005. However, production was shut in again when Hurricanes Katrina and Rita moved through the Gulf of Mexico in August and September of 2005. Hurricane Katrina destroyed the Main Pass 306D platform. No platforms were lost to Hurricane Rita. However, the back-to-back hurricanes caused damage to third party processing and pipeline facilities that have slowed reinstatement of Noble Energy's production. The Company estimates that 2005 production was reduced by approximately 6,700 Boepd due to the effects of the hurricanes.

Gulf of Mexico Shelf – A 2005 workover program has been successful in maximizing the value of the Company's existing asset base in the Gulf of Mexico shelf area. The workover program will continue into 2006.

Gulf Coast – Activities in the Gulf Coast area during 2005 targeted larger prospects such as the Laurents #1 (South Lake Arthur Deep) which is a 21,000 foot Marg tex test. The well is currently drilling. Noble Energy operates the well with a 54% working interest.

International – Noble Energy has significant international operations. Production from international locations accounted for 42% of 2005 Company-wide production. At December 31, 2005, approximately 47% of the Company's proved reserves were in foreign locations. International proved reserves are approximately 63% natural gas and 37% crude oil. Operations in Equatorial Guinea, Ecuador and China are conducted in accordance with the terms of production sharing contracts. Noble Energy has operations in the following countries:

Equatorial Guinea – The Company's operations in Equatorial Guinea accounted for 66% of international proved reserves at December 31, 2005 and 52% of 2005 international production (including production from an equity method investee). Activities in this West African country center around a working interest in the offshore Alba field, one of Noble Energy's most significant assets. Operations include the Alba field and related condensate production facilities, an onshore LPG processing plant, and a methanol plant. With the completion of recent expansion projects (Phase 2A and 2B) the current condensate capacity is 21,000 Bpd net to Noble Energy and current LPG capacity is 5,600 Bpd net to Noble Energy. The methanol plant is designed to produce commercial grade methanol at a rate of 2,500 MTpd for sale to domestic and international customers. The Company's share of methanol production totaled 162,446 MGal during 2005. Noble Energy owns a 34% working interest in the Alba field and related condensate production facilities, a 28% interest in the LPG plant (through an equity method investee) and a 45% interest in the methanol plant (through an equity method investee).

Blocks "O" and "I" are operated by Noble Energy and represent new exploration opportunities for the Company. In October 2005, Noble Energy announced a discovery on Block "O" with successful test results from the "O-1" ("Belinda") exploration well. The Company is planning to perform additional appraisal and exploratory work on Block "O" and expects to begin exploratory work on Block "I" in 2006. Noble Energy is the technical operator of both blocks, with a 45% working interest in Block "O" and a 40% working interest in Block "I". Block "O", offshore Bioko Island, covers 437,871 acres and is located in water depths that range from the Bioko Island shoreline to over 500 meters (1,640 feet). Block "I", adjacent to Block "O", covers 199,167 acres and is located in water depths in excess of 500 meters. Two 3-D seismic surveys exist on Block "O" and one 3-D seismic survey exists on Block "I".

At December 31, 2005, the Company held 45,203 gross developed acres and 903,792 gross undeveloped acres offshore Equatorial Guinea.

Israel – The Company's properties in Israel are a core international asset, comprising 17% of international proved reserves at December 31, 2005. During 2005, natural gas production from the offshore Mari-B field totaled 66 MMcfpd net to Noble Energy, representing 18% of international production. Noble Energy has a 47% working interest in the field and is the operator. During 2005 the Company began construction of a permanent onshore receiving terminal for distribution of natural gas from the Mari-B field to purchasers. The project is expected to be completed by the end of 2006. At December 31, 2005, 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.

North Sea – The Company's operation in the North Sea is another core asset. The North Sea properties comprised 6% of international proved reserves at December 31, 2005 and 11% of 2005 international production. In 2005, the Company sanctioned development of the non-operated Dumbarton field (30% working interest). Development plans include drilling and subsea tie-back to the GP III, a floating production, storage and offloading vessel in which the Company will own a 30% interest, with production anticipated to begin in first quarter 2007. At December 31, 2005, the Company held 34,580 gross developed acres and 444,385 gross undeveloped acres in the North Sea.

***Ecuador* –** Projects in Ecuador accounted for 6% of international proved reserves at December 31, 2005 and 6% of 2005 international production. Noble Energy's operations in Ecuador consist of a 100%-owned integrated natural gas-to-power project. The project includes the Amistad field, 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. The concession covers 12,355 gross developed acres and 851,771 gross undeveloped acres.

China – Noble Energy's production from China totaled 5 MBopd, net to the Company's interest, during 2005 and represented 8% of international production. The Company's properties in China represented 2% of the Company's international proved reserves at December 31, 2005. Noble Energy, as operator, has a 57% working interest in the Cheng Dao Xi field, which is located in the shallow water of the southern Bohai Bay. The Company plans to drill two additional development wells (one directional and one horizontal) during 2006. At December 31, 2005, the Company held 7,413 gross developed acres and no undeveloped acres in China.

Argentina – The Company's operations in Argentina represented 5% of 2005 international production and 2% of international proved reserves at December 31, 2005. The Company's producing properties are located in southern Argentina in the El Tordillo field (13% working interest), which is characterized by secondary recovery crude oil production. During 2005, Noble Energy participated in the drilling of 58 gross (7.7 net) development wells in the El Tordillo field and plans to continue development drilling in 2006. At December 31, 2005, the Company held 113,325 gross developed acres and no undeveloped acres in Argentina.

Suriname – Suriname, a country located on the northern coast of South America, represents a new exploration project for Noble Energy. The Company has a 30% working interest in Block 30. Block 30 (non-operated) covers approximately four million acres with two-thirds of the block in water depth greater than 600 feet. A seismic program is currently underway. Noble Energy and its partners plan to drill the first exploration well offshore Suriname during 2007.

Production, Price and Cost Data – Production, price and cost data for continuing operations are as follows:

	Production		Average Sales Price		Average Production Cost
	Natural Gas MMcf	Crude Oil MBbls	Natural Gas Per Mcf[4]	Crude Oil Per Bbl[4]	Per BOE[5]
Year Ended December 31, 2005					
U.S.	125,543	9,468	$7.43	$46.67	$7.39
Equatorial Guinea[1]	23,938	6,492	0.25	42.51	2.93
Israel	24,228	–	2.68	–	2.11
North Sea	3,394	1,964	5.93	52.68	7.54
Other International[2]	8,389	2,866	1.10	42.37	7.15
Total Consolidated Operations	185,492	20,790	5.78	45.35	6.06
Equity Investee[3]	–	1,183	–	43.43	
Total	185,492	21,973	$5.78	$45.25	
Year Ended December 31, 2004					
U.S.	88,077	7,951	$6.03	$32.64	$5.84
Equatorial Guinea[1]	16,747	3,364	0.25	38.16	3.38
Israel	17,573	–	2.78	–	2.46
North Sea	4,130	2,459	4.73	38.90	6.13
Other International[2]	7,782	2,506	0.75	31.06	5.67
Total Consolidated Operations	134,309	16,280	4.76	34.48	5.20
Equity Investee[3]	–	327	–	32.01	
Total	134,309	16,607	$4.76	$34.44	
Year Ended December 31, 2003					
U.S.	95,104	5,871	$4.83	$26.79	$4.93
Equatorial Guinea[1]	14,566	1,994	0.25	28.34	3.04
Israel	–	–	–	–	–
North Sea	5,059	2,705	3.86	29.95	4.93
Other International[2]	8,134	2,242	0.41	26.67	6.56
Total Consolidated Operations	122,863	12,812	4.19	27.67	4.86
Equity Investee[3]	–	333	–	25.47	
Total	122,863	13,145	$4.19	$27.62	

(1) Natural gas in Equatorial Guinea is under contract for $0.25 per MMBtu to a methanol plant through 2026 and to an LPG plant. Sales from the Alba field to these plants are based on a BTU equivalent and then converted to a dry gas equivalent volume. Both of these plants are owned by affiliated entities accounted for under the equity method of accounting. The volumes produced by the LPG plant are included in the crude oil information.

(2) Other International gas production includes Ecuador and Argentina. Although Ecuador natural gas sales volumes are included in Other International production, they are excluded from average natural gas sales prices. The natural gas-to-power project in Ecuador is 100% owned by Noble Energy and intercompany natural gas sales are eliminated. Natural gas production volumes associated with the gas-to-power project were 8,320 MMcf for 2005, 7,640 MMcf for 2004, and 7,842 MMcf for 2003. Other International oil production includes China and Argentina.

(3) Volumes represent sales of condensate and LPG from the Alba plant in Equatorial Guinea. LPG volumes were 2,328 Bopd, 706 Bopd, and 701 Bopd for 2005, 2004, and 2003, respectively.

(4) Average natural gas sales prices for the U.S. reflect reductions of $0.77 per Mcf (2005), $0.08 per Mcf (2004) and $0.44 per Mcf (2003) from hedging activities. Average crude oil sales prices for the U.S. reflect reductions of $8.03 per Bbl (2005), $3.05 per Bbl (2004) and $1.01 per Bbl (2003) from hedging activities. Average crude oil sales prices for Equatorial Guinea reflect a reduction of $9.93 (2005) from hedging activities.

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

Productive Wells – The number of productive crude oil and natural gas wells in which Noble Energy held an interest as of December 31, 2005 follows:

	Crude Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
United States – Onshore	6,550.0	5,088.6	3,860.0	2,552.2	10,410.0	7,640.8
United States – Offshore	172.0	111.8	171.0	75.8	343.0	187.6
International	773.0	106.7	28.0	10.3	801.0	117.0
Total	7,495.0	5,307.1	4,059.0	2,638.3	11,554.0	7,945.4

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. 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, 2005. Included in non-producing wells are productive wells awaiting additional action, pipeline connections or shut-in for various reasons.

	Crude Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Multiple Completions	7.0	4.6	20.0	8.1	27.0	12.7
Not Producing (Shut-in)	1,954.0	1,256.9	496.0	295.5	2,450.0	1,552.4

Developed and Undeveloped Acreage – The developed and undeveloped acreage (including both leases and concessions) that Noble Energy held at December 31, 2005 is as follows:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
U.S.:				
Onshore	1,267,048	718,997	812,750	450,500
Offshore	644,454	295,463	711,166	504,718
Total U.S.	1,911,502	1,014,460	1,523,916	955,218
Israel	123,552	58,142	292,572	137,681
Argentina	113,325	15,548	–	–
Equatorial Guinea	45,203	15,727	903,792	397,672
Ecuador	12,355	12,355	851,771	851,771
China	7,413	4,225	–	–
North Sea(1)	34,580	1,838	444,385	195,133
Total International	336,428	107,835	2,492,520	1,582,257
Total Worldwide (2)	2,247,930	1,122,295	4,016,436	2,537,475

(1) The North Sea includes acreage in the United Kingdom, the Netherlands and Norway.

(2) If production is not established, approximately 220,758 gross acres (129,787 net acres), 233,949 gross acres (142,453 net acres), and 285,545 gross acres (152,548 net acres) will expire during 2005, 2006 and 2007, respectively.

Developed acreage is acreage spaced or assignable to productive wells. 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. 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.

Drilling Activity – The following table shows the results of crude oil and natural gas wells drilled for each of the last three fiscal years:

	Net Exploratory wells			Net Development Wells		
	Productive	Dry	Total	Productive	Dry	Total
Year Ended December 31, 2005						
U.S.	4.7	10.7	15.4	488.1	25.9	514.0
Equatorial Guinea	–	–	–	0.3	–	0.3
North Sea	–	0.2	0.2	–	–	–
Argentina	–	–	–	7.7	–	7.7
Total	4.7	10.9	15.6	496.1	25.9	522.0
Year Ended December 31, 2004						
U.S.	10.7	8.5	19.2	62.4	8.7	71.1
Equatorial Guinea	–	0.3	0.3	2.4	–	2.4
North Sea	0.3	0.7	1.0	0.1	–	0.1
China	–	–	–	1.7	–	1.7
Argentina	–	–	–	10.0	–	10.0
Ecuador	–	–	–	3.0	–	3.0
Total	11.0	9.5	20.5	79.6	8.7	88.3
Year Ended December 31, 2003						
U.S.	10.8	12.4	23.2	25.1	8.2	33.3
North Sea	0.1	0.6	0.7	0.1	–	0.1
Israel	–	0.5	0.5	–	–	–
China	–	1.0	1.0	–	–	–
Argentina	–	–	–	7.2	–	7.2
Vietnam	–	0.6	0.6	–	–	–
Total	10.9	15.1	26.0	32.4	8.2	40.6

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

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 table above 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.

At December 31, 2005, Noble Energy was drilling 88 gross (67.3 net) development wells and 5 gross (2.5 net) exploration wells. These wells are located onshore in Argentina and North America (Alabama, Colorado, Illinois, Indiana, Kansas, Louisiana, New Mexico, Oklahoma and Texas) and offshore Gulf of

Mexico. The drilling cost to Noble Energy of these wells will be approximately $86.2 million if all are dry and approximately $119.7 million if all are completed as producing wells.

Title to Properties

Noble Energy believes that its title to the various interests set forth above is satisfactory and consistent with generally accepted industry standards, subject to exceptions that are not so material as to detract substantially from the value of the interests or materially interfere with their use in the Company's operations. Individual properties may be subject to burdens such as royalty, overriding royalty and other outstanding interests customary in the industry. In addition, interests may be subject to obligations or duties under applicable laws or burdens such as production payments, net profits interest, liens incident to operating agreements and for current taxes, development obligations under crude oil and natural gas leases or capital commitments under production sharing contracts or exploration licenses.

Item 3. Legal Proceedings.

The ruling by the Colorado Supreme Court in *Rogers v. Westerman Farm Co.* in July 2001 resulted in uncertainty regarding the deductibility of certain post-production costs from payments to be made to royalty interest owners. In January 2003, Patina was named as a defendant in a lawsuit, which plaintiff sought to certify as a class action, based upon the *Rogers* ruling alleging that Patina had improperly deducted certain costs in connection with its calculation of royalty payments relating to its Wattenberg field operations *(Jack Holman, et al v. Patina Oil & Gas Corporation; Case No. 03-CV-09; District Court, Weld County, Colorado)*. In May 2004, the plaintiff filed an amended complaint narrowing the class of potential plaintiffs, and thereafter filed a motion seeking to certify the narrowed class as described in the amended complaint. Patina filed an answer to the amended complaint. A motion seeking class certification was heard on September 22, 2005 and granted on October 13, 2005. The Colorado Supreme Court denied the Company's petition for review on November 23, 2005.

The Illinois Environmental Protection Agency (IEPA) issued a notice of violation to Equinox Oil Company on September 25, 2001 alleging violation of air emission and permitting regulations for a facility known as the Zif Gas Plant located near Clay City, Illinois. Elysium Energy, LLC acquired Equinox, and Elysium subsequently was acquired by Patina. The facility is a small amine processing unit used to treat and remove hydrogen sulfide from natural gas prior to transportation. The notice of violation alleges violation of permit requirements under the Clean Air Act dating back to 1986 as well as excessive hydrogen sulfide emissions at the plant. The Company is cooperatively working with the IEPA staff to address this matter. It is within the discretion of the IEPA to assess a fine for violating emission and permit regulations but the Company has not been assessed a fine or other penalty at this time.

The Company and its subsidiaries are involved in various legal proceedings, including the foregoing matters, in the ordinary course of business. These proceedings are subject to the uncertainties inherent 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.

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 2005.

Executive Officers of the Registrant

The following table sets forth certain information, as of March 1, 2006, with respect to the executive officers of the Registrant.

Name	Age	Position
Charles D. Davidson[1]	56	Chairman of the Board, President, Chief Executive Officer and Director
Chris Tong[2]	49	Senior Vice President, Chief Financial Officer
Frederick B. Bruning[3]	57	Chief Accounting Officer
Alan R. Bullington[4]	54	Senior Vice President, International
Robert K. Burleson[5]	48	Senior Vice President, Business Administration and President, Noble Energy Marketing, Inc.
Susan M. Cunningham[6]	50	Senior Vice President, Exploration and Corporate Reserves
Arnold J. Johnson [7]	50	Vice President, General Counsel and Secretary
David L. Stover[8]	48	Senior Vice President, North America

(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. 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 1972 to October 1993, he held various positions with ARCO.

(2) Chris Tong was elected a Senior Vice President and Chief Financial Officer of the Company on 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 served over a year with Superior Oil Company as a Reservoir Engineering Assistant.

(3) Frederick B. Bruning was appointed Chief Accounting Officer of the Company on November 14, 2005. Previous to his employment with the Company, he was employed as Vice President of Business Operations for Fidelity National Financial, Business Systems Group from March 2004 to September 2005 and as Chief Financial Officer for two companies in the technology sector from March 1999 to March 2004. Previously, he served with Occidental Petroleum Corporation in various financial and accounting leadership positions, including Vice President-International Finance and Vice President & Controller of Occidental Oil and Gas Corporation from June 1974 to March 1999. He previously served as Senior Auditor with Ernst and Young, LLC from June 1970 to June 1974.

(4) Alan R. Bullington was elected a Senior Vice President of the Company on July 27, 2004 and is currently responsible for the Company's International Division. 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.

(5) Robert K. Burleson was elected a Senior Vice President of the Company on July 27, 2004 and is currently responsible for the Company's Business Administration. Prior thereto, he served as Vice President of the Company since April 24, 2001 and has been responsible for Business Administration 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.

(6) Susan M. Cunningham was elected a Senior Vice President in April 2001 and is currently responsible for Exploration and Corporate Reserves of the Company. 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 held various exploration and development positions until 1997.

(7) 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. Previous to his employment with the Company, 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. From 1980 to March 1989, he held various positions with ARCO.

(8) David L. Stover was elected a Senior Vice President of the Company on July 27, 2004 and is currently responsible for the Company's North America Division. 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 America, Inc. 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. From 1979 to 1994, he held various positions with ARCO.

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, $3.33⅓ 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
2005			
First quarter	$34.35	$28.06	$0.025
Second quarter	39.22	31.66	0.025
Third quarter	47.52	38.81	0.050
Fourth quarter	47.79	35.96	0.050
2004			
First quarter	24.24	21.33	0.025
Second quarter	26.03	21.81	0.025
Third quarter	29.41	24.49	0.025
Fourth quarter	32.30	28.31	0.025

Transfer Agent and Registrar. The transfer agent and registrar for the Common Stock is American Stock Transfer & Trust Company, 59 Maiden Lane, New York, New York 10038.

Stockholders' Profile. Pursuant to the records of the transfer agent, as of February 14, 2006, the number of holders of record of Common Stock was 886.

Stock Repurchases. The Company did not repurchase any of its outstanding Common Stock during 2005.

Equity Compensation Plan Information. The following table summarizes information regarding the number of shares of common stock of the Company that are outstanding and available for issuance under all of the Company's existing equity compensation plans as of December 31, 2005.

Plan Category	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	9,319,642	$19.21	5,984,008
Equity compensation plans not approved by security holders	–	–	–
Total	9,319,642	$19.21	5,984,008

Item 6. Selected Financial Data

	Year ended December 31,				
	2005[1]	2004	2003	2002	2001
	(in thousands, except share amounts)				
Revenues and Income:					
Revenues	$2,186,723	$1,351,051	$1,008,226	$ 703,068	$ 800,003
Income from continuing operations	645,720	313,850	89,892	8,095	85,163
Net income	645,720	328,710	77,992	17,652	133,575
Per Share Data:[2]					
Basic earnings per share –					
Income from continuing operations	$ 4.20	$ 2.69	$ 0.79	$ 0.07	$ 0.75
Net income	4.20	2.82	0.68	0.15	1.18
Cash dividends	0.150	0.100	0.085	0.080	0.080
Year-end stock price	40.30	30.83	22.22	18.78	17.65
Basic weighted average shares outstanding	153,773	116,550	113,928	114,392	113,098
Financial Position:					
Property, plant, and equipment, net	$6,198,916	$2,180,715	$2,046,909	$2,128,140	$1,944,887
Goodwill	862,868	–	–	–	–
Total assets	8,878,033	3,435,784	2,820,800	2,730,016	2,604,255
Long-term obligations –					
Long-term debt	2,030,533	880,256	776,021	977,116	961,118
Deferred income taxes	1,201,191	180,415	161,912	201,939	176,259
Asset retirement obligations	278,540	175,415	101,804	–	–
Derivative instruments	757,509	9,678	7,400	337	822
Other deferred credits and noncurrent liabilities	279,971	69,479	72,776	69,483	74,807
Shareholders' equity	3,090,144	1,459,988	1,073,573	1,009,386	1,010,198
Continuing Operations Information:					
Natural gas production (Mcfpd)	508,195	366,965	336,611	341,008	355,632
Average realized price ($/Mcf)	$ 5.78	$ 4.76	$ 4.19	$ 2.89	$ 3.86
Crude oil production (Bopd)	56,958	44,481	35,101	28,232	24,277
Average realized price ($/Bbl)	$ 45.35	$ 34.48	$ 27.67	$ 24.22	$ 23.49
Equity investee production (Bopd)	3,240	894	913	882	696
Average realized price ($/Bbl)	$ 43.43	$ 32.01	$ 25.47	$ 17.82	$ 18.39

(1) Includes effect of Patina Merger. See "Item 8. Financial Statements and Supplementary Data – Note 3 – Merger with Patina Oil & Gas Corporation" for additional information.

(2) Per share data have been adjusted to reflect the two-for-one stock split, effected in the form of a stock dividend, of the Company's common stock effective September 14, 2005.

See "Item 8. Financial Statements and Supplementary Data" for additional information.

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, in the exploration, development, production and marketing of crude oil and natural gas. The Company has exploration, exploitation and production operations domestically and internationally. Noble Energy operates throughout major basins in the United States including Colorado's Wattenberg field, the Mid-continent region of western Oklahoma and the Texas Panhandle, the San Juan basin in New Mexico, the Gulf Coast and the Gulf of Mexico. Noble Energy also operates internationally, in Equatorial Guinea, the Mediterranean Sea, Ecuador, the North Sea, China, Argentina and Suriname.

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 is a worldwide producer of crude oil and natural gas. The Company's strategy is to achieve growth in earnings and cash flow through the development of a high quality portfolio of producing assets that is balanced between domestic and international projects. The Patina Merger allowed Noble Energy to achieve a strategic objective of enhancing its U.S. asset portfolio and has resulted in a company with assets and capabilities that include growing U.S. basins, coupled with a significant portfolio of international properties. After the Patina Merger Noble Energy has approximately 36% greater production than 2004 with a reserve base that is balanced between domestic and foreign sources. In addition, the Company has been reducing its investment in the Gulf of Mexico's conventional shallow shelf and shifting its domestic offshore exploration focus to Gulf of Mexico deepwater areas. Noble Energy is now a larger, more diversified company with greater opportunities for both domestic and international growth through high upside exploration drilling as well as lower risk exploitation projects.

The Company had a successful year, both financially and operationally, in 2005. Financial highlights included the following:

- successful completion of the Patina Merger;
- record net income of $645.7 million, a 96% increase over 2004;
- diluted earnings per share of $4.12, a 48% increase over 2004;
- cash flow provided by operating activities of $1.2 billion, a 75% increase over 2004; and
- entry into a new $2.1 billion five-year revolving credit facility.

Significant operational highlights included the following:

- a 36% increase in daily equivalent production over 2004, including a 35% domestic increase and a 38% international increase;
- increases of 32% in the average realized crude oil price and 21% in the average realized natural gas price over 2004;
- increases in average realized methanol, LPG and Ecuador power prices;
- first production from the deepwater Gulf of Mexico "Swordfish" development;
- "Belinda" discovery on Block "O" in Equatorial Guinea;
- completion and start-up of Phase 2B (liquids expansion project) in Equatorial Guinea;
- sanctioning of the Dumbarton development in the North Sea;
- sanctioning of the Lorien development in the deepwater Gulf of Mexico;
- deepwater Gulf of Mexico exploration agreement with Samson Offshore Company signed in December; and
- impact of Hurricanes Katrina and Rita.

Merger with Patina Oil & Gas Corporation – On May 16, 2005, Noble Energy completed the Patina Merger in a transaction accounted for as a purchase of Patina by Noble Energy. Patina was an independent energy company engaged in the acquisition and development of crude oil and natural gas properties within the continental United States. Patina's properties and crude oil and natural gas reserves are principally located in relatively long-lived fields with established production histories. The properties are primarily concentrated in the Wattenberg field of Colorado's D-J basin, the Mid-continent region of western Oklahoma and the Texas Panhandle, and the San Juan basin in New Mexico. Noble Energy acquired the common stock of Patina for a total purchase price of approximately $4.9 billion, which was comprised primarily of cash and Noble Energy common stock, plus liabilities assumed. In exchange for Patina's common stock and options, Noble Energy issued 55.7 million shares of stock valued at $1.7 billion, issued options valued at $104.9 million, paid $1.1 billion in cash to Patina shareholders and assumed debt of

$610.5 million and deferred taxes of $1.1 billion. The consolidated operating and cash flow information includes financial results of Patina after May 16, 2005.

Domestic Operations – Domestic operations benefited from higher realized prices for crude oil and natural gas in 2005, and a 35% overall increase in production. During 2005, Noble Energy drilled 644 gross domestic onshore and 22 gross domestic offshore wells.

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

- Swordfish (Viosca Knoll Block 917, 961 and 962) – Three subsea wells were tied back via dual flowlines to Kerr-McGee's Neptune spar in Viosca Knoll 826 and production began fourth quarter 2005 with a production volume of approximately 8,500 Boepd, net to the Company (60% working interest);
- Lorien (Green Canyon Block 199) – A successful development well was drilled in 2005 and both the discovery well and development well were completed. Installation of subsea infrastructure to tie the wells back to a nearby host 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 (60% working interest);
- Ticonderoga (Green Canyon Block 768) – A successful development well was drilled in 2005 and both the discovery well and development well were completed with a subsea tieback. Ticonderoga achieved first production on February 16, 2006 and has achieved peak production volumes of approximately 8,750 Bopd and 6,600 Mcfpd, net to Noble Energy's 50% working interest.

Impact of Gulf Coast Hurricanes – In August 2005 Hurricane Katrina moved through the Gulf of Mexico and resulted in the loss of the Main Pass 306D platform. In September 2005 Hurricane Rita struck the Gulf Coast. Initial inspection of the Company's operated platforms indicated there was no additional major damage due to Hurricane Rita, although damage to third party processing and pipeline facilities slowed reinstatement of production from the Company's Gulf of Mexico assets. In addition, the hurricanes delayed efforts to restore sales of production from undamaged platforms at Main Pass 293/305/306 that were shut-in by Hurricane Ivan in 2004. The Company estimates that 2005 production was reduced by approximately 6,700 Boepd due to the effects of the hurricanes. The loss of production is not covered by business interruption insurance.

International Operations – During 2005, international production volumes increased 38%, compared to 2004, primarily from increased production in Equatorial Guinea. International operations also benefited from higher realized commodity prices. In Equatorial Guinea, the Phase 2B liquids expansion project, which included increasing processing capacity, storage and offloading facilities at the existing LPG plant, has been completed and has increased LPG production by 1,622 Bbls per day and condensate production by 724 Bbls per day, net to Noble Energy, during 2005. In October 2005, Noble Energy announced successful results from its offshore Belinda exploration well on Block "O" in Equatorial Guinea. The Company is currently reviewing options for a multi-well exploration and appraisal program, which is expected to begin in 2006. Noble Energy is the technical operator of Block "O" with a 45% participating interest.

2006 OUTLOOK

In February 2006, Noble Energy announced that it had agreed to purchase the common stock of U.S. Exploration, a privately held corporation located in Billings, Montana, for $411.0 million. Subject to customary conditions, the transaction is scheduled to close on or before March 29, 2006. Prior to closing, U.S. Exploration will retire all company debt, terminate its commodity hedges and make all severance payments. Capital spending on the U.S. Exploration properties will be focused on accelerating production and reserve development. In 2006, capital expenditures are expected to be approximately $100 million.

Noble Energy has executed hedges on its own production volumes from March 2006 through 2010 that are equivalent to just over 50% of U.S. Exploration's expected volumes. The hedges are in the form of collars. The average floors on the natural gas hedges and crude oil hedges are $6.23 per MMBtu and $58.74 per Bbl. The average ceilings on the natural gas hedges and crude oil hedges are $9.17 MMBtu and $72.52 per Bbl. The natural gas hedges are priced at the CIG index and thereby include basis differentials to Henry Hub.

The Company expects crude oil and natural gas production from continuing operations to increase in 2006 compared to 2005. The expected year-over-year increase in production is impacted by several factors:

- a full year of production including assets acquired in the Patina Merger;
- the contribution of the Swordfish deepwater Gulf of Mexico development, which commenced production fourth quarter 2005;
- the start-up of production from the Ticonderoga and Lorien deepwater Gulf of Mexico developments, which are expected to begin producing in the first and second quarters of 2006, respectively; and
- a full year of production from the Phase 2B liquids expansion project in Equatorial Guinea.

Noble Energy's production profile will be impacted by several factors, including:

- the timing and amount of initial production from Ticonderoga and Lorien;
- seasonal variations in rainfall in Ecuador that affect the Company's natural gas-to-power project;
- potential weather-related shut-ins in the U.S. Gulf of Mexico and Gulf Coast areas; and
- downtime associated with plant maintenance or turnaround.

2006 Budget – The Company has budgeted capital expenditures of $1.26 billion for 2006. Approximately 23% of the 2006 capital budget has been allocated to exploration opportunities and 77% has been allocated to production, development and other projects. Domestic spending is budgeted for $860 million (68% of the 2006 capital budget), international expenditures are budgeted for $380 million (30%) and corporate expenditures are budgeted for $20 million (2%). The 2006 budget does not include the impact of possible asset purchases, including the previously announced pending purchase of U.S. Exploration as well as anticipated development costs associated with U.S. Exploration. The Company expects that its 2006 capital 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.

Accounting for Share-Based Payments – In December 2004, the Financial Accounting Standards Board 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 on or after January 1, 2006. The Company will adopt SFAS No. 123(R) as of January 1, 2006, using the modified prospective transition method. Under the modified prospective transition 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 January 1, 2006 will be accounted for in accordance with SFAS No. 123, except that the amounts will be expensed in the Company's consolidated statements of operations. Upon adoption of SFAS No. 123(R), the balance of deferred compensation relating to restricted stock in the Company's shareholders' equity account will be reversed against capital in excess of par value in accordance with the transition requirements. Due to the complexity of developing a model to adequately value the Company's share-based compensation awards, the Company has not yet quantified the impact of the new statement, but it is expected to increase compensation expense in 2006.

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.

Purchase Price Allocation – As a result of the Patina Merger, in May 2005 the Company acquired the assets and assumed the liabilities of Patina in a transaction accounted for as a purchase of Patina by the Company. In connection with a purchase business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

In estimating the fair values of Patina's assets and liabilities the Company made various assumptions. The most significant assumptions related to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. To estimate the fair values of these properties, the Company prepared estimates of crude oil and natural gas reserves. The Company estimated future prices to apply to the estimated reserve quantities acquired, and estimated future operating and development costs, to arrive at estimates of future net revenues. For estimated proved reserves, the future net revenues were discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the merger. The market-based weighted average cost of capital rate was subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net revenues of probable and possible reserves were reduced by additional risk-weighting factors.

Estimated deferred taxes were based on available information concerning the tax basis of Patina's assets and liabilities and loss carryforwards at the merger date, although such estimates may change in the future as additional information becomes known.

While the estimates of fair value for the assets acquired and liabilities assumed have no effect on Noble Energy's cash flows, they can have an effect on the future results of operations. Generally, higher fair values assigned to crude oil and natural gas properties result in higher future depreciation, depletion and amortization expense, which results in a decrease in future net earnings. Also, a higher fair value assigned to crude oil and natural gas properties, based on higher future estimates of crude oil and natural gas prices, could increase the likelihood of an impairment in the event of lower commodity prices or higher operating costs than those originally used to determine fair value. An impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

Certain data necessary to complete the Company's final purchase price allocation is not yet available, and includes, but is not limited to, final valuation of pre-acquisition contingencies, final tax returns that provide the underlying tax bases of Patina's assets and liabilities at May 16, 2005, and final appraisals of assets acquired and liabilities assumed. The Company expects to complete its valuation of assets and liabilities (including deferred taxes) for the purpose of allocation of the total purchase price amount to assets acquired and liabilities assumed during the twelve-month period following the acquisition date. Any future change in the value of net assets up until the one year period has expired will be offset by a corresponding increase or decrease in goodwill. Any change in deferred tax assets and liabilities as of the merger date (May 16, 2005) based on information that becomes available later will be recorded as an increase or decrease in goodwill.

Goodwill – As of December 31, 2005 Noble Energy has $862.9 million of goodwill recorded in connection with the Patina Merger. The goodwill was assigned to the Company's domestic reporting unit. Goodwill is not amortized to earnings but is tested, at least annually, for impairment at the reporting unit level. The Company conducted its goodwill impairment test as of December 31, 2005. Other events and changes in circumstances may also require goodwill to be tested for impairment between annual measurement dates. If the carrying value of goodwill is determined to be impaired, the amount of goodwill is reduced and a corresponding charge is made to earnings in the period in which the goodwill is determined to be impaired.

The impairment assessment requires management to make estimates regarding the fair value of the reporting unit to which goodwill has been assigned. The Company determines the fair value of its domestic reporting unit using a combination of the income approach and the market approach. Under the income approach, the Company estimates the fair value of the reporting unit based on the present value of expected future cash flows. Under the market approach, the Company estimates the fair value based on market multiples of EBITDA (earnings before interest, taxes, and depreciation, depletion and amortization ("DD&A")) and EBIT (earnings before interest and taxes).

The income approach is dependent on a number of factors including estimates of forecasted revenue and operating costs, proved reserves, as well as the success of future exploration for and development of unproved reserves, appropriate discount rates and other variables. Downward revisions of estimated reserve quantities, increases in future cost estimates, divestiture of a significant component of the reporting unit, or sustained decreases in natural gas or crude oil prices could lead to an impairment of all or a portion of goodwill in future periods. Under the market approach, the Company makes certain judgments about the selection of comparable companies, comparable recent company and asset transactions and transaction premiums. Although the Company has based its fair value estimate on assumptions it believes to be reasonable, those assumptions are inherently unpredictable and uncertain and actual results could differ from the estimate. In 2005, no goodwill impairment was recognized.

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 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 to determine if the carrying amount of crude oil and natural gas properties exceeds fair value and could result in an impairment charge which would reduce earnings.

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. In addition, under the full cost method capitalized costs are accumulated in pools on a country-by-country basis. DD&A is computed on a country-by-country basis, and capitalized costs are limited on the same basis through the application of a ceiling test. 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 this method is better aligned with the Company's business strategy. If the Company had used the full cost method, its financial position and results of operations could have been significantly different.

Exploratory Well Costs – In accordance with the successful efforts method of accounting, the costs associated with drilling an exploratory well may be capitalized temporarily, or "suspended," pending a determination of whether commercial quantities of crude oil or natural gas have been discovered. The Company will carry the costs of an exploratory well as an asset if the well found a sufficient quantity of reserves to justify its capitalization as a producing well and as long as the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. 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 access to necessary facilities and access to such permits and approvals and believes they will be obtained. Management assesses the status of its suspended exploratory well costs on a quarterly basis. 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, 2005, the balance of property, plant and equipment included $35.2 million of suspended exploratory well costs, none of which 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."

Proved 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 $5.4 million of impairments in 2005, primarily related to downward reserve revisions on certain domestic properties.

Unproved Oil and Gas Properties – The Company also performs periodic assessments of individually significant unproved crude oil and natural gas properties for impairment. Cash flows used in the impairment analysis are determined based upon management's estimates of natural gas and crude oil reserves, future commodity prices and future costs to extract the reserves. Downward revisions in estimated reserve quantities, reductions in commodity prices, or increases in estimated costs could cause a reduction in the value of an unproved property and, therefore, could also cause a reduction in the carrying amounts of the property. If undiscounted future net cash flows are less than the carrying value of the property, indicating an impairment, the cash flows are discounted at a rate approximate to the Company's cost of capital and compared to the carrying value for determining the amount of the impairment loss to record. The estimated prices used in the cash flow analysis are determined by management based on forward price curves for the related commodities, adjusted for average historical location and quality differentials. Estimates of cash flows related to probable and possible reserves are reduced by additional risk-weighting factors. Due to the volatility of natural gas and crude oil prices, these cash flow estimates are inherently imprecise. Management's assessment of the results of exploration activities, availability of funds for future activities and the current and projected political climate in areas in which the Company operates also impact the amounts and timing of impairment provisions. During 2005, the Company recorded impairments of significant unproved oil and gas properties totaling $3.1 million.

Asset Retirement Obligation – The Company's asset retirement obligations ("ARO") consist 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; and inflation rates. 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, 2005, the Company's balance sheet included a liability for ARO of $338.9 million, including $163.8 million resulting from hurricane damage. See "Note 6 – Asset Retirement Obligations."

Involuntary Conversions – When an involuntary conversion occurs, such as the destruction of oil and gas producing assets by a hurricane, the Company accrues a loss by a charge to income if the amount of loss can be reasonably estimated. The Company recognizes an asset relating to insurance recovery only when realization of the claim for recovery of a loss recognized in the financial statements is deemed probable. The Company does not recognize a gain (a recovery of a loss not yet recognized in the financial statements or an amount recovered in excess of a loss recognized in the financial statements) until the insurance reimbursement has been received.

Management of the Company must make a number of estimates and assumptions relating to these gain and loss accruals. These include estimated costs of salvage, clean-up, restoration, redevelopment or abandonment and estimated amounts of insurance recoveries. The amount of an insurance recovery may be limited if total industry claims are in excess of the insurance provider's ceiling limitation per event. A significant amount of time may be necessary for an insurance provider to review all related claims for an event and determine the Company-specific claim limitation on the final recovery. In addition, the Company may continue to incur costs, submit claims and receive reimbursements over a multi-year period.

The estimates involved in this process can have significant effects on reported amounts of net income. A decrease in the estimated amount of insurance recoveries will result in a decrease in the involuntary conversion gain, which will result in a decrease in net income. An increase in estimated costs of salvage will result in an increase in the involuntary conversion loss, which will result in a decrease in net income. Unreimbursed losses will have a negative effect on the Company's cash flows.

Derivative Instruments and Hedging Activities – The Company uses various derivative instruments to minimize the impact of commodity price fluctuations on forecasted sales of crude oil and natural gas production. The Company also uses derivative instruments in connection with its purchases and sales of third-party production to lock in profits or limit exposure to commodity price risk. In addition, the Company has used derivative instruments in connection with acquisitions and certain price-sensitive projects. 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 hedged 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 are reported in current period net income and therefore can result in significant increases or decreases in current period net income. All hedge ineffectiveness is recognized in the current period in net income. Ineffectiveness is the amount of gains or losses from derivative instruments which are not offset by corresponding and opposite gains or losses on the expected future transaction. Regression analysis is performed on initial assessment of the hedge and subsequently every quarter thereafter in order to determine that the hedge instrument will be or has been highly effective in offsetting gains or losses on the future transaction.

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 American Jobs Creation Act of 2004, assessment of the effects of foreign taxes on domestic taxes, and estimates regarding the timing and amounts of future repatriation of earnings from controlled foreign corporations.

The Company's balance sheet includes deferred tax assets related to deductible temporary differences and operating loss carryforwards and foreign tax credits. Ultimately, realization of a deferred tax asset depends on the existence of sufficient taxable income within the future periods to absorb future deductible temporary differences, loss carryforwards or credits. 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. The Company will continue to monitor facts and circumstances in its reassessment of the likelihood that operating loss carryforwards, credits 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.

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, rates of future compensation increases, estimated future employee turnover rates and retirement dates, distribution election rates, mortality rates, 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, 2005, the Company had cumulative asset losses of approximately $3.4 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 regarding future events. 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% equity and 30% fixed income, with a range of plus or minus 10% 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 1% decrease in the expected return on plan assets assumption would have increased 2005 benefit expense by $0.9 million. The expected return assumption for 2005 is 8.25%, and the assumed discount rate for 2005 is 6.00%.

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. A new $2.1 billion unsecured five-year credit facility, with $820 million in remaining funds available at December 31, 2005, will provide increased liquidity in 2006.

The Company's ratio of debt-to-book capital (defined as the Company's total debt divided by the sum of total debt plus equity) was 40% at December 31, 2005, compared to 38% at December 31, 2004. Significant changes in the Company's financial position causing a change in the ratio of debt-to-book capital include:

- increases in total debt related to the funding of the Patina Merger and additional capital expenditures;
- an increase in retained earnings from current year net income;
- an increase in capital in excess of par value from the issuance of stock in the Patina Merger; and
- a decrease in accumulated other comprehensive income (loss) related to an increase in deferred hedge losses.

Cash Flows

Operating Activities – The Company reported a $531.7 million year-over-year increase in cash flows from operating activities. Net cash provided by operating activities totaled $1.2 billion for the year ended December 31, 2005, compared to $708.2 million in 2004 and $602.8 million in 2003. The increases for 2005 and 2004 were driven by overall production increases, higher realized commodity prices and higher distributions from earnings of an equity method investee.

Investing Activities – Net cash used in investing activities totaled $1.9 billion, $588.1 million and $444.8 million for the years ending December 31, 2005, 2004 and 2003, respectively. The Company's 2005 investing activities relate primarily to the Patina Merger as well as expenditures made for the exploration and development of crude oil and natural gas properties. Expenditures were offset by the receipt of $13.2 million, $62.5 million and $81.1 million from sales of assets during 2005, 2004 and 2003, respectively.

Financing Activities – Net cash provided by (used in) financing activities totaled $583.1 million, $(2.7) million and $(111.0) million for the years ending December 31, 2005, 2004 and 2003, 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 2005, the Company had a net $1.2 billion increase in outstanding debt primarily related to the Patina Merger. In addition, the Company received $67.7 million from the exercise of stock options.

Acquisition, Exploration and Development-Related Expenditures

Values preliminarily allocated to proved and unproved crude oil and natural gas properties acquired in the Patina Merger were $2.6 billion and $1.1 billion, respectively. The Company's exploration and development-related expenditure information (on an accrual basis) is as follows:

	Year ended December 31,		
	2005	**2004**	**2003**
		(in thousands)	
Exploration and Development – Related Expenditures:			
Exploratory drilling and completion	$ 41,739	$ 31,295	$ 67,665
Dry hole	98,015	46,192	63,637
Lease acquisition costs	16,793	44,685	10,234
Seismic	21,761	23,360	17,674
Total exploration expenditures	178,308	145,532	159,210
Development drilling and completion	662,585	399,217	325,990
Corporate and other	21,478	22,639	16,873
Total exploration and development – related expenditures from consolidated operations	$862,371	$567,388	$502,073
Company's share of equity method investee's capital spending	$ 27,639	$ 61,498	$ 41,944
Capital expenditures budget	962,000	750,000	510,000

Total capital expenditures during 2005 increased $261.1 million, or 42%, as compared with 2004. The increase includes $275.1 million of post-merger exploration and development-related expenditures on Patina properties. Capital expenditures during 2004 increased $84.9 million, or 16%, 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 2005 were lower than budgeted amounts due to cost reductions and increased lead times for international capital outlays, offset by costs of an expanded domestic drilling program. 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 liquids expansion project 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 liquids expansion project in Equatorial Guinea.

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 $130 million. The Company's consolidated financial statements have been reclassified for all periods previously presented to reflect the operations 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 $13.2 million, $62.5 million and $81.1 million in 2005, 2004 and 2003, 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 $2.035 billion (excluding unamortized discount) at December 31, 2005, all of which was long-term. Maturities range from 2009 to 2097.

The Company's principal source of liquidity is a new $2.1 billion unsecured five-year credit facility (the "New Facility") entered into in December 2005. The New Facility is available (a) to refinance existing indebtedness of the Company, and (b) for general corporate purposes. The New Facility is with certain commercial lending institutions and bears interest rates based upon a Eurodollar rate plus a range of 20.0 basis points to 95.0 basis points depending upon the Company's credit rating and utilization of the New Facility. The New Facility has facility fees that range from 7.5 basis points to 17.5 basis points depending upon the Company's credit rating. At December 31, 2005, $1.28 billion in borrowings were outstanding under the New Facility.

The New Facility contains customary representations and warranties and affirmative and negative covenants, including, but not limited to, the following financial covenants: (a) the ratio of Earnings Before Interest, Taxes, Depreciation and Exploration Expense 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; and (b) the total debt to capitalization ratio, expressed as a percentage, may not exceed 60% at any time. A violation of these covenants will result in a default under the New Facility, which could permit the participating banks to restrict the Company's ability to access the New Facility and require the immediate repayment of any outstanding advances under the New Facility. At December 31, 2005, the ratios were 18.7 to 1.0 and 34.5%. The total debt to capitalization ratio for this purpose is calculated as the Company's total debt divided by the sum of debt plus equity, with increases or decreases thereto as provided by the New Facility.

Upon acquisition of the New Facility, the Company repaid and terminated its existing credit facilities, which consisted of a $400 million credit agreement due October 2009, a $400 million credit agreement due November 2006, and a $1.3 billion acquisition facility due April 2010. The $1.3 billion acquisition facility was used by the Company to finance a portion of the cash consideration paid in the Patina Merger and the repayment of Patina debt. The Company also prepaid $45 million on its term loans due January 2009. See "Item 8. Financial Statements and Supplementary Data – Note 7 – Debt – Term Loans."

The Company made cash interest payments of $92.5 million, $46.6 million and $46.0 million during 2005, 2004 and 2003, respectively.

Dividends – The Company paid quarterly cash dividends of two cents per share from 1989 through third quarter 2003. For fourth quarter 2003, for each quarter of 2004, and for the first two quarters of 2005, the Company's Board of Directors declared a quarterly cash dividend of 2.5 cents per common share. In third quarter 2005, the Company's Board of Directors declared an increase in the quarterly cash dividend to five cents per common share. (The above amounts have been adjusted for the Company's two-for-one stock split, effected in the form of a stock dividend, in third quarter 2005.) The Board of Directors declared a quarterly cash dividend of five cents per common share for fourth quarter 2005. On January 24, 2006, the Board of Directors declared a quarterly cash dividend of five cents per common share, payable February 21, 2006 to shareholders of record on February 6, 2006. 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 $67.7 million, $62.6 million and $24.7 million from the exercise of stock options during 2005, 2004 and 2003, 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. Of the $67.7 million received from the exercise of stock options during 2005, approximately $43.5 million resulted from the exercise of Patina options that had been exchanged for Noble Energy options in the Patina Merger.

Off-Balance Sheet Arrangements

The Company may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2005, the material off-balance sheet arrangements and transactions that the Company has entered into included operating lease agreements, drilling commitments, undrawn letters of credit, and derivative contracts. Other than the off-balance sheet arrangements listed above, the Company has no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect the Company's liquidity or availability of or requirements for capital resources. See "Contractual Obligations" below for more information regarding the Company's off-balance sheet arrangements.

Contractual Obligations

The following table summarizes certain contractual obligations that are reflected in the consolidated balance sheets and/or disclosed in the accompanying Notes.

	Payments Due by Period				
	Total	2006	2007 and 2008	2009 and 2010	2011 and Beyond
			(in thousands)		
Contractual Obligations:					
Long-term debt (Note 7)	$2,035,000	$ –	$ –	$1,385,000	$ 650,000
Service contracts –					
Gulf of Mexico drilling rig	375,057	–	–	64,335	310,722
Gulf of Mexico salvage vessel	72,842	72,842	–	–	–
Other drilling rigs and services	54,895	47,842	7,053	–	–
Operating lease obligations –					
Oil and gas operations equipment	4,140	1,704	2,436	–	–
Office buildings and facilities	32,154	4,986	8,709	8,367	10,092
Purchase obligations –					
North Sea FPSO	83,160	83,160	–	–	–
Other purchase obligations (1)	31,873	31,873	–	–	–
Other long-term liabilities –					
Asset retirement obligations (Note 6) (2)	338,871	60,331	87,859	13,615	177,066
Derivative instruments (Note 12)	1,156,931	416,681	735,061	5,189	–
Total contractual obligations	$4,184,923	$719,419	$841,118	$1,476,506	$1,147,880

(1) Represents obligations to purchase long lead oil and gas equipment.
(2) 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 $3.9 million at December 31, 2005.

Other

Contributions to Pension and Other Postretirement Benefit Plans – The Company made contributions to its pension and other postretirement benefit plans of $13.9 million during 2005, $4.7 million during 2004, and $14.6 million during 2003. The Company expects to make cash contributions of $7.2 million to its pension plan during 2006. The actual returns on plan assets were $5.7 million in 2005, $7.9 million in 2004, and $7.6 million in 2003. The investment return has tended to follow market performance.

Income Taxes – The Company made cash payments for income taxes of $121.7 million during 2005, $112.3 million during 2004 and $55.5 million during 2003.

Contingencies – During 2005, 2004, and 2003 no significant payments were made to settle any of the Company's legal proceedings. 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.

RESULTS OF OPERATIONS

Net Income and Revenues

The Company's net income for 2005 was $645.7 million, an increase of 96% compared to 2004 net income. Factors contributing to the change in net income included:

- the successful completion of the Patina Merger in May;
- a 36% overall increase in production, with 90% of the increase attributed to Patina properties;
- a 68%, or $381.4 million, increase in crude oil sales due to a 28% increase in consolidated daily production and a 32% increase in average realized crude oil prices;
- a 70%, or $420.1 million, increase in natural gas sales due to a 38% increase in daily production and a 21% increase in average realized natural gas prices;
- a 52%, or $61.4 million, increase in exploration expense; and
- a 16%, or $12.6 million, increase in income from equity method investees involved in the production and sale of condensate, LPG and methanol in Equatorial Guinea.

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

- a 58%, or $206.8 million, increase in crude oil sales due to a 27% increase in consolidated daily production and a 25% increase in average realized crude oil prices;
- a 25%, or $121.3 million, increase in natural gas sales due to a 9% increase in daily production and a 14% increase in average realized natural gas prices;
- a 21%, or $31.8 million, decrease in exploration expense; and
- a 73%, or $33.0 million, increase in income from equity method investments.

Natural Gas Information

Natural gas revenues increased 70% in 2005 compared to 2004 due to a 21% increase in average realized natural gas prices and a 38% increase in daily natural gas production. Natural gas revenues increased 25% in 2004, compared to 2003, due to a 14% increase in natural gas prices and a 9% increase in daily natural gas production.

	Year ended December 31,		
	2005	**2004**	**2003**
		(in thousands)	
Natural gas sales	$1,023,644	$603,571	$482,285

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

	2005		2004		2003	
	Mcfpd	$/Mcf	Mcfpd	$/Mcf	Mcfpd	$/Mcf
United States [(1)]	343,953	$7.43	240,647	$6.03	260,560	$4.83
Equatorial Guinea [(2)]	65,581	0.25	45,755	0.25	39,906	0.25
North Sea	9,299	5.93	11,286	4.73	13,861	3.86
Israel	66,377	2.68	48,015	2.78	–	–
Ecuador [(3)]	22,795	–	20,875	–	21,485	–
Other International	190	1.10	387	0.75	799	0.41
Total	508,195	$5.78	366,965	$4.76	336,611	$4.19

(1) Reflects reductions of $0.77 per Mcf in 2005, $0.08 per Mcf in 2004 and $0.44 per Mcf in 2003 from hedging in the United States.

(2) Natural gas in Equatorial Guinea is under contract for $0.25 MMBtu through 2026 to a methanol plant and year-to-year to an LPG plant. Sales from the Alba field to these plants are based on a BTU equivalent and then converted to a dry gas equivalent volume. Both of these plants are owned by affiliated entities accounted for under the equity method of accounting. The volumes produced by the LPG plant are included in the table below under crude oil information.

(3) The natural gas-to-power project in Ecuador is 100% owned by a subsidiary of Noble Energy and intercompany natural gas sales are eliminated for accounting purposes. Electricity sales of $74.2 million, $58.6 million, and $58.0 million are included in total revenues for 2005, 2004 and 2003, respectively.

Factors contributing to the change in natural gas production included:

- additional domestic production (140 MMcfpd) from newly-acquired Patina properties;
- increase in Phase 2A (Alba field expansion project) production and start-up of Phase 2B (liquids expansion project) in Equatorial Guinea;
- higher production in Israel which commenced second quarter 2004;
- loss of production due to Gulf of Mexico hurricanes;
- natural field decline in the Gulf of Mexico and North Sea; and
- increase in production in Ecuador.

Crude Oil Information

Crude oil revenues increased 68% during 2005, compared to 2004, due to a 32% increase in crude oil prices and a 28% increase in consolidated daily crude oil production. Crude oil revenues increased 58% during 2004, compared to 2003, due to a 25% increase in crude oil prices and a 27% increase in daily crude oil production.

	Year ended December 31,		
	2005	2004	2003
		(in thousands)	
Crude oil sales	$942,778	$561,404	$354,575

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

	2005		2004		2003	
	Bopd	$/Bbl	Bopd	$/Bbl	Bopd	$/Bbl
United States [1]	25,941	$46.67	21,725	$32.64	16,084	$26.79
Equatorial Guinea [2]	17,786	42.51	9,190	38.16	5,464	28.34
North Sea	5,380	52.68	6,718	38.90	7,412	29.95
Other International [3]	7,851	42.37	6,848	31.06	6,141	26.67
Total Consolidated Operations	56,958	45.35	44,481	34.48	35,101	27.67
Equity Investee [4]	3,240	43.43	894	32.01	913	25.47
Total	60,198	$45.25	45,375	$34.44	36,014	$27.62

(1) Reflects reductions of $8.03 per Bbl in 2005, $3.05 per Bbl in 2004 and $1.01 per Bbl in 2003 from hedging activities.
(2) Reflects reductions of $9.93 per Bbl in 2005 from hedging activities.
(3) Other international includes China and Argentina.
(4) Volumes represent sales of condensate and LPG from the Alba plant in Equatorial Guinea. LPG volumes were 2,328 Bopd, 706 Bopd, and 701 Bopd for 2005, 2004, and 2003, respectively.

Factors attributing to the change in crude oil production included:

- additional domestic production (12 Mbopd) from newly-acquired Patina properties;
- increase in Phase 2A (Alba field expansion project) production and start-up of Phase 2B (liquids expansion project) in Equatorial Guinea;
- new production from the Swordfish development in the Gulf of Mexico;
- loss of production due to Gulf of Mexico hurricanes;
- increase in production in China; and
- natural field decline in the North Sea.

Gathering, Marketing and Processing

NEMI, a wholly-owned subsidiary, marketed approximately 55% of Noble Energy's domestic natural gas production in 2005, 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 also markets certain third-party crude oil. NEMI's gross margin from gathering, marketing and processing ("GMP") activities was as follows:

	2005	2004	2003
		(in thousands)	
Proceeds	$55,261	$49,250	$68,158
Total expenses	28,067	37,699	59,114
Gross margin	$27,194	$11,551	$ 9,044

NEMI employs derivative instruments in connection with its purchases and sales of third-party production to lock in profits or limit exposure to commodity 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. The net loss related to these contracts totaled $1.5 million during 2005. Gains (losses) were *de minimis* for 2004 and 2003.

GMP proceeds for 2005, includes a gain of $11.2 million for the sale of certain gas sales and transportation contractual assets.

Electricity Sales – Ecuador Integrated Power Project

The Company, through its subsidiaries, EDC Ecuador Ltd. and MachalaPower Cia. Ltda., has a 100% 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.

Operating data is as follows:

	Year ended December 31,		
	2005	2004	2003
Operating income (in thousands)	$ 21,091	$ 10,839	$ 7,176
Power production (MW)	799,160	720,300	751,689
Average power price ($/Kwh)	$ 0.093	$ 0.081	$ 0.077

The volume of natural gas and electric power produced in Ecuador are related to thermal electricity demand in Ecuador which typically declines 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 only to meet peak demand. As seasonal rains subside, the Company experiences increasing demand for thermal electricity.

Electricity generation expense for 2005 and 2004 includes $11.3 million and $5.4 million, respectively, for net increases in the allowance for doubtful accounts. These increases have been made to cover potentially uncollectible balances related to the Ecuador power operations. Certain entities purchasing electricity in Ecuador have been slow to pay amounts due Noble Energy. The Company is pursuing various strategies to protect its interests including international arbitration and litigation.

Income from Equity Method Investees

Noble Energy owns a 45% interest in AMPCO, which owns and operates a methanol production facility and related facilities in Equatorial Guinea and a 28% interest in Alba Plant, which owns and operates an LPG processing plant. Noble Energy owns 50% interests in AMPCO Marketing, LLC and AMPCO Services, LLC, which provide technical and consulting services. These investments are accounted for using the equity method. The Company's share of operations of the equity method investees was as follows:

	Year ended December 31,		
	2005	2004	2003
Income from AMPCO LLC (in thousands)	$54,982	$66,807	$38,235
Dividends from AMPCO (in thousands)	$59,625	$57,825	$46,125
Income from Alba Plant LLC (in thousands)	$33,916	$ 9,099	$ 4,560
Income from other equity method investees (in thousands)	$ 1,914	$ 2,293	$ 2,391
Methanol sales volumes (gallons in thousands)	162,446	146,821	122,015
Methanol averaged realized price per gallon	$ 0.77	$ 0.69	$ 0.65
Condensate sales volumes (barrels in thousands)	333	69	77
Condensate average realized price per barrel	$ 55.76	$ 37.25	$ 28.32
LPG sales volumes (barrels in thousands)	850	259	256
LPG average realized price per barrel	$ 38.63	$ 30.62	$ 24.61

The Company received a $31.4 million cash payment from Alba Plant, LLC on February 2, 2006.

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 variable to fixed price swaps and costless collars. 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 2005, 2004 and 2003, the Company recognized a reduction of revenues of $237.7 million, $61.3 million and $67.5 million related to its cash flow hedges in oil and gas sales and royalties. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk – Commodity Price Risk."

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 $112.4 million, or 56%, in 2005 compared to 2004. The increase was due to higher production volumes attributed to newly-acquired Patina properties and to higher per-unit production and ad valorem taxes.

Production costs increased $39.3 million, or 24%, 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.

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

	Total	*United States*	*Equatorial Guinea*	*North Sea*	*Israel* [2]	*Corporate & Other Int'l* [3]
			(in thousands)			
Year Ended December 31, 2005						
Lease operating[1]	$203,833	$136,087	$30,661	$12,244	$8,504	$16,337
Workover expense	14,027	13,734	–	259	–	34
Total operations expense	217,860	149,821	30,661	12,503	8,504	16,371
Production and ad valorem	78,703	65,428	–	–	–	13,275
Transportation expense	16,764	9,350	–	6,562	–	852
Total production costs	$313,327	$224,599	$30,661	$19,065	$8,504	$30,498
Year Ended December 31, 2004						
Lease operating[1]	$136,471	$ 85,013	$20,811	$ 8,803	$7,203	$14,641
Workover expense	16,635	16,635	–	–	–	–
Total operations expense	153,106	101,648	20,811	8,803	7,203	14,641
Production and ad valorem	28,022	21,806	–	–	–	6,216
Transportation expense	19,808	8,631	–	10,480	–	697
Total production costs	$200,936	$132,085	$20,811	$19,283	$7,203	$21,554
Year Ended December 31, 2003						
Lease operating[1]	$111,724	$ 72,107	$13,441	$ 8,453	$ –	$17,723
Workover expense	6,303	6,303	–	–	–	–
Total operations expense	118,027	78,410	13,441	8,453	–	17,723
Production and ad valorem	22,722	17,850	–	–	–	4,872
Transportation expense	20,888	10,877	–	9,024	–	987
Total production costs	$161,637	$107,137	$13,441	$17,477	$ –	$23,582

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

(2) Sales began in first quarter 2004.

(3) Other international includes Ecuador, China and Argentina.

Selected expenses on a per BOE basis were as follows:

	Year ended December 31,		
	2005	2004	2003
Lease operating	$3.94	$3.53	$3.36
Workover expense	0.27	0.43	0.19
Total operations expense	4.21	3.96	3.55
Production and ad valorem taxes	1.52	0.73	0.68
Transportation expense	0.33	0.51	0.63
Total production costs	$6.06	$5.20	$4.86

Depreciation, Depletion and Amortization Expense – In 2005, DD&A expense from continuing operations increased $82.4 million, or 27%, due to higher production from Patina properties and in Equatorial Guinea. In 2005, DD&A expense includes $11.3 million of abandoned assets expense and $14.2 million of DD&A related to capitalized asset retirement costs. The DD&A rate for 2005 has decreased primarily due to increasing low-cost volumes in Equatorial Guinea and Israel.

In 2004, DD&A expense from continuing operations remained flat versus 2003. 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 capitalized asset retirement costs.

Included in DD&A for 2003 is $20.6 million of abandoned assets expense and $20.2 million of DD&A related to capitalized asset retirement costs. The table below includes the DD&A from continuing operations:

	Year ended December 31,		
	2005	2004	2003
		(in thousands)	
United States	$311,153	$240,058	$254,041
Equatorial Guinea	27,121	13,925	5,358
North Sea	9,888	18,244	28,219
Israel	11,188	9,058	40
Other International, Corporate, and Other	31,194	26,818	20,928
Total DD&A expense	$390,544	$308,103	$308,586
Unit rate of DD&A per BOE	$ 7.55	$ 7.97	$ 9.27

Exploration Expense – Crude oil and natural gas exploration expense consists of dry hole expense, unproved lease amortization and impairment, 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.

	Total	*United States*	*Equatorial Guinea*	*North Sea*	*Israel*	*Corporate & Other Int'l* [(1)]
			(in thousands)			
Year Ended December 31, 2005						
Dry hole expense	$ 98,015	$ 95,678	$1,403	$ 932	$ 2	$ –
Unproved lease amortization	17,855	17,855	–	–	–	–
Seismic	21,761	11,631	316	1,544	–	8,270
Staff expense	34,945	16,255	3,760	2,690	189	12,051
Other	5,850	4,974	(16)	819	32	41
Total exploration expense	$178,426	$146,393	$5,463	$ 5,985	$ 223	$20,362
Year Ended December 31, 2004						
Dry hole expense	$ 46,192	$ 34,236	$4,676	$ 6,789	$ 293	$ 198
Unproved lease amortization	19,280	18,705	–	50	525	–
Seismic	23,360	20,288	2,115	550	–	407
Staff expense	22,990	13,926	260	3,374	305	5,125
Other	5,179	4,737	163	402	–	(123)
Total exploration expense	$117,001	$ 91,892	$7,214	$11,165	$1,123	$ 5,607
Year Ended December 31, 2003						
Dry hole expense	$ 63,637	$ 32,408	$ –	$ 4,023	$6,711	$20,495
Unproved lease amortization	33,381	25,296	–	1,264	900	5,921
Seismic	17,674	15,903	51	1,662	–	58
Staff expense	30,182	17,483	83	3,105	214	9,297
Other	3,944	3,601	–	449	–	(106)
Total exploration expense	$148,818	$ 94,691	$ 134	$10,503	$7,825	$35,665

(1) Other international includes Ecuador, China and Argentina.

Exploration expense increased $61.4 million, or 52%, during 2005 as compared with 2004. The increase was due to increased dry hole expense in the U.S. where a total of 36.8 net wells were classified as dry holes and expensed during the year. Exploration expense declined $31.8 million, or 21%, in 2004 compared with 2003. Costs related to 18.2 net wells were included in dry hole expense for 2004. 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. Costs related to 23.3 net wells were included in dry hole expense for 2003.

Impairment of Operating Assets

During 2005, the Company recorded $5.4 million of impairments, related to downward reserve revisions on four domestic properties. In 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 a Gulf of Mexico property after recompletion and remediation activities produced less-than-expected results.

Selling, General and Administrative Expenses

Selling, general and administrative ("SG&A") expenses increased $38.3 million, or 62%, in 2005 compared to 2004 and increased $6.9 million, or 13%, in 2004 compared to 2003. The increase in SG&A expenses for 2005 reflects additional costs incurred relating to the combined operations of Noble Energy and Patina. The increase in SG&A expenses for 2004 primarily reflects fees associated with the implementation of

Sarbanes-Oxley and increased salaries and bonuses. On a BOE basis, SG&A expenses were $1.94, $1.60 and $1.65 for the years ended December 31, 2005, 2004 and 2003, respectively.

Interest Expense and Capitalized Interest

Interest expense totaled $96.2 million, $61.6 million and $61.1 million during 2005, 2004 and 2003, respectively. Capitalized interest totaled $8.7 million, $8.2 million and $13.4 million during 2005, 2004 and 2003, respectively. Interest is capitalized on the Company's development projects using an interest rate equivalent to the average rate paid on the Company's long-term debt. Capitalized interest is included in the cost of oil and gas assets and amortized with other costs on a unit-of-production basis. The majority of the capitalized interest relates to long lead-time projects in the deepwater Gulf of Mexico and internationally, primarily Phase 2A in Equatorial Guinea.

Interest expense includes $0.8 million in 2005 and $0.5 million in 2004 related to the reclassification of the deferred hedging loss from AOCI related to 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 AOCI and is being amortized into earnings as an adjustment to interest expense over the term of the Company's 5¼% Senior Notes due April 2014.

Deferred Compensation Adjustment

In connection with the Patina Merger, Noble Energy acquired the assets and assumed the liabilities related to a deferred compensation plan. The assets of the deferred compensation plan are held in a rabbi trust and include shares of Noble Energy common stock, which are classified as treasury stock. Increases or decreases in the market value of the deferred compensation liability, including the shares of Noble Energy common stock held by the rabbi trust, are included as deferred compensation adjustments in the Company's consolidated statements of operations. The Company recorded deferred compensation expense of $17.9 million from the date of the Patina Merger through December 31, 2005. At December 31, 2005, 69% of the market value of the assets in the rabbi trust related to Noble Energy common stock.

Loss on Involuntary Conversion

The net loss on involuntary conversion of assets for 2005 is equal to the amount of the Company's insurance deductible related to damage caused by Hurricane Katrina which primarily consisted of the destruction of the Main Pass 306D platform. Estimated salvage and clean-up expenses are expected to cost $67.0 million. The Company has been notified by its insurance carrier that it should expect to recover no more than 50% of its total claim due to submission of total industry claims from Katrina damage in excess of a $1 billion ceiling limitation per event. However, the Company currently expects to recover sufficient insurance proceeds to cover the expected salvage and clean-up costs and has offset anticipated insurance proceeds against the accrued salvage and clean-up expense except for the $1.0 million deductible.

The loss for 2004 is the insurance deductible related to infrastructure damage at Main Pass 293/305/306 caused by Hurricane Ivan. The Company expects to fully recover through insurance proceeds all salvage and clean-up expenses and a portion of its redevelopment capital. Future additional expenditures for redevelopment will be capitalized as development costs, net of any remaining insurance proceeds.

As of December 31, 2005, based upon work completed, Noble Energy has submitted $84.0 million (cumulative) in claims related to Hurricane Ivan damage, none of which has been disputed, and received $49.0 million (cumulative) in reimbursements. The Company received an additional $35.0 million in reimbursements in January 2006. In February 2006, the Company received insurance reimbursements of $6.4 million related to Hurricane Katrina damage. Noble Energy expects to continue to incur costs, submit claims and receive reimbursements in the normal course of business in 2006 and beyond. The Company will adjust the total loss attributable to the involuntary conversions in the period in which the contingencies related to the replacement costs are resolved. The Company does not recognize a gain until the insurance reimbursement has been received. The loss of production is not covered by business interruption insurance.

Pension Expense

The Company recognized an actuarially-computed net periodic benefit expense related to its pension and other postretirement benefit plans of $11.0 million, $9.1 million and $7.9 million during 2005, 2004 and 2003, respectively. This expense reflects an expected return on pension plan assets of 8.25%, 8.5% and 8.5% during 2005, 2004 and 2003, 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, 2005 and 2004 of $18.6 million and $13.1 million, respectively. During 2005, the allowance had a net increase of $5.6 million which included an increase of $11.3 million, net of collections, for Ecuador power operations, offset by $6.4 million in final write-offs of allowances recorded in prior years. 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), Net

As a result of the impacts of Hurricanes Katrina and Rita on the timing of the Company's forecasted production during the fourth quarter of 2005, derivative instruments hedging approximately 6,000 barrels per day of crude oil and 40,000 MMBtu per day of natural gas no longer qualified for hedge accounting. Accordingly, beginning October 1, 2005 the changes in fair value of these derivative contracts were recognized in the Company's results of operations, causing a mark-to-market gain of $20.0 million ($13.0 million, net of tax). In addition, the delay in the timing of the Company's production resulted in a loss of $51.8 million in fourth quarter 2005 ($33.7 million, net of tax) related to amounts previously recorded in AOCI. Both the gain and the loss are included in other expense (income), net on the statements of operations.

Other expense (income), net 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 received a total of $8.2 million in cash as part of the exchange.

Other expense (income), net for 2003 includes gains related to the sale of various domestic properties, excluding the properties included in discontinued operations.

Income Taxes

Income tax expense associated with continuing operations increased to $322.9 million in 2005 from $199.2 million in 2004 due primarily to the increase in income. The effective income tax rate decreased to 33.3% in 2005 from 38.8% in 2004. This decrease is primarily due to the Company's ability to claim a foreign tax credit for the income taxes paid by its foreign branch operations, as well as to a benefit realized on the repatriation of foreign earnings under the American Jobs Creation Act. Income tax expense associated with continuing operations increased to $199.2 million in 2004 from $50.5 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 effective income tax rate increased to 38.8% in 2004 from 36.0% 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 which is taxed at lower rates than income sourced from operations outside the U.S. See "Note 8 – Income Taxes."

Discontinued Operations

Summarized results of discontinued operations are as follows for the years ended December 31:

	2004	2003
	(in thousands)	
Oil and gas sales and royalties	$12,575	$106,339
Write down to market value and realized gain (loss)	14,996	(59,171)
Income (loss) before income taxes	22,862	(9,325)
Key Statistics:		
Daily production		
Liquids (Bbls)	225	4,106
Natural Gas (Mcf)	4,429	32,823
Average realized price		
Liquids (Bbls)	$ 33.96	$ 27.71
Natural Gas ($/Mcf)	$ 6.03	$ 5.41

Cumulative Effect of Change in Accounting Principle, Net of Tax

The Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations" 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.

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

Commodity Price 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 variable to fixed price swaps and costless collars.

As of December 31, 2005, the Company had open costless collar positions 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	Bopd	Floor	Ceiling
2006 (NYMEX)	3,699	$5.00	$8.00	1,865	$29.00	$34.93
2007 (Brent)	–	–	–	6,748	45.00	70.63
2008 (Brent)	–	–	–	4,077	45.00	66.52
2009 (Brent)	–	–	–	3,074	45.00	63.04

As of December 31, 2005, the Company had open fixed price swap positions related to its natural gas and crude oil production as follows:

	Natural Gas		Crude Oil	
Production Period	MMBtupd	Average Price per MMBtu	Bopd	Average price per Bbl
2006 (NYMEX)(1)	170,000	$6.49	16,600	$40.47
2007 (NYMEX)	170,000	6.04	17,100	39.19
2008 (NYMEX)	170,000	5.67	16,500	38.23

(1) Includes derivative instruments of 40,000 MMBtupd of natural gas and 6,000 Bopd of crude oil that did not qualify for hedge accounting treatment at December 31, 2005. These derivative instruments were re-designated as cash flow hedges in February 2006.

The hedging instruments above represent 27% of the Company's expected worldwide natural gas production in 2006, 2007, and 2008, and 22% of the Company's expected worldwide crude oil production in 2006, 2007, and 2008. As of December 31, 2005, the Company had a net unrealized loss of $1.2 billion (pre-tax) related to crude oil and natural gas derivative instruments entered into for hedging purposes. A net unrealized loss of $763.8, net of tax, is recorded in AOCI in the shareholders' equity section of the Company's balance sheet and will be recognized in earnings as adjustments to revenue as the individual contracts are settled.

In anticipation of the purchase of U.S. Exploration, expected to close on or before March 29, 2006, Noble Energy has executed hedges on its own production volumes. The hedges are for the period March 2006 through 2010 and are equivalent to just over 50% of U.S. Exploration's expected volumes. The hedges are in the form of collars. The average floors on the natural gas hedges and crude oil hedges are $6.23 per MMBtu and $58.74 per Bbl. The average ceilings on the natural gas hedges and crude oil hedges are $9.17 per MMBtu and $72.52 per Bbl. The natural gas hedges are priced at the CIG index and thereby include basis differentials to Henry Hub. The instruments have been designated as cash flow hedges.

Derivative Instruments Held for Trading Purposes – NEMI, from time to time, employs various derivative instruments in connection with its purchases and sales of production. While most of the purchases are made for an index-based price, customers often require prices that are either fixed or related to NYMEX. In order to establish a fixed margin and mitigate the risk of price volatility, NEMI may convert a fixed or NYMEX sale to an index-based sales price (such as purchasing a NYMEX futures contract at the Henry Hub with an adjoining basis swap at a physical location). Due to the size of such transactions and certain restraints imposed by contract and by Noble Energy guidelines, the Company believes it had no material market risk exposure from these derivative instruments as of December 31, 2005. Unrealized gains and losses are reflected in earnings as incurred.

Interest Rate Risk

The Company is exposed to interest rate risk related to its variable and fixed interest rate debt. As of December 31, 2005, the Company had $2.035 billion of debt outstanding of which $650 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, 2005 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, 2005, $1.385 billion of variable-rate debt was outstanding. A 10% change in the floating interest rates applicable to the December 31, 2005 balance would result in a change in annual interest expense of approximately $6.7 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, 2005, AOCI included $4.1 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 Company's 5¼% Senior Notes due April 2014.

Foreign Currency Risk

The Company has not entered 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), net on the statements of operations.

Item 8. Financial Statements and Supplementary Data.

INDEX TO FINANCIAL STATEMENTS

Consolidated Financial Statements of Noble Energy, Inc.

Financial Statements of Atlantic Methanol Production Company, LLC

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 consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States.

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

As of December 31, 2005, 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, 2005, based on those criteria. Management included in its assessment of internal control over financial reporting all consolidated entities except those falling under Patina. Noble Energy acquired Patina in May 16, 2005. Patina's internal control over financial reporting related to total assets of $4.1 billion and total revenues of $670.2 million as of and for the year ended December 31, 2005. As permitted by the SEC's published guidance, we excluded these entities from our assessment as they were acquired near mid-year and it was not possible to conduct our assessment between the date of acquisition and the end of the year.

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, 2005 and is included herein.

Noble Energy, Inc.

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Noble Energy, Inc. and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of operations, shareholders' equity, comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2005. 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 did not audit the financial statements of Atlantic Methanol Production Company, LLC (AMPCO), the investment in which, as described in Note 13 of the financial statements, is accounted for by the equity method of accounting. The Company's investment in AMPCO at December 31, 2005 and 2004, was $214.2 million and $211.5 million, respectively, and its equity in earnings of AMPCO was $54.9 million and $66.8 million for the years 2005 and 2004, respectively. The financial statements of AMPCO were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for AMPCO, is based solely on the report of the other auditors.

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 and the reports of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of the other auditors, 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, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2005, 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, 2005, 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 1, 2006 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Houston, Texas
March 1, 2006

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders 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, 2005, 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, 2005, 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, 2005, based on criteria established in Internal Control – Integrated Framework issued by COSO.

Noble Energy, Inc. acquired Patina Oil and Gas Corporation during 2005, and management excluded from its assessment of the effectiveness of Noble Energy, Inc.'s internal control over financial reporting as of December 31, 2005, Patina Oil and Gas Corporation's internal control over financial reporting associated with total assets of $4.1 billion and total revenues of $670.2 million included in the consolidated financial statements of Noble Energy, Inc. and subsidiaries as of and for the year ended December 31, 2005. Our audit of internal control over financial reporting of Noble Energy, Inc. also excluded an evaluation of the internal control over financial reporting of Patina Oil and Gas Corporation.

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, 2005 and 2004, and the related consolidated statements of operations, shareholders' equity, comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2005, and our report dated March 1, 2006 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Houston, Texas
March 1, 2006

Noble Energy, Inc. and Subsidiaries
Consolidated Balance Sheets
(in thousands, except share amounts)

	December 31, 2005	December 31, 2004
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 110,321	$ 179,794
Accounts receivable – trade, net	566,206	406,608
Derivative instruments	29,258	28,733
Materials and supplies inventories	33,802	12,109
Deferred taxes	237,045	13,039
Prepaid expenses and other	56,568	28,278
Probable insurance claims	142,311	65,000
Total current assets	1,175,511	733,561
Property, Plant and Equipment, at Cost:		
Oil and gas mineral interests, equipment and facilities (successful efforts method of accounting)	8,411,426	4,136,088
Other	69,869	56,707
	8,481,295	4,192,795
Accumulated depreciation, depletion and amortization	(2,282,379)	(2,012,080)
Total property, plant and equipment, net	6,198,916	2,180,715
Equity Method Investments	420,362	377,384
Other Assets	220,376	144,124
Goodwill	862,868	–
Total Assets	$ 8,878,033	$ 3,435,784
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable – trade	$ 519,971	$ 428,401
Derivative instruments	445,939	50,304
Interest payable	11,340	11,439
Income taxes	65,136	63,521
Asset retirement obligations	60,331	79,568
Accrued and other current liabilities	137,428	27,320
Total current liabilities	1,240,145	660,553
Deferred Income Taxes	1,201,191	180,415
Asset Retirement Obligations	278,540	175,415
Derivative Instruments	757,509	9,678
Deferred Compensation Liability	141,185	10,224
Other Deferred Credits and Noncurrent Liabilities	138,786	59,255
Long-Term Debt	2,030,533	880,256
Total Liabilities	5,787,889	1,975,796
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; 250,000,000 shares authorized; 184,893,510 and 125,144,834 shares issued, respectively	616,311	417,152
Capital in excess of par value	1,945,239	291,458
Deferred compensation	(5,288)	(1,671)
Accumulated other comprehensive loss	(783,499)	(14,787)
Treasury stock, at cost: 9,268,932 and 7,099,952 shares, respectively	(148,476)	(75,956)
Retained earnings	1,465,857	843,792
Total Shareholders' Equity	3,090,144	1,459,988
Total Liabilities and Shareholders' Equity	$ 8,878,033	$ 3,435,784

The accompanying notes are an integral part of these financial statements

Noble Energy, Inc. and Subsidiaries
Consolidated Statements of Operations
(in thousands, except per share amounts)

	Year ended December 31,		
	2005	2004	2003
Revenues:			
Oil and gas sales and royalties	$1,966,422	$1,164,975	$ 836,860
Gathering, marketing and processing	55,261	49,250	68,158
Electricity sales	74,228	58,627	58,022
Income from equity method investments	90,812	78,199	45,186
Total Revenues	2,186,723	1,351,051	1,008,226
Costs and Expenses:			
Oil and gas operations	217,860	153,106	118,027
Production and ad valorem taxes	78,703	28,022	22,722
Transportation	16,764	19,808	20,888
Oil and gas exploration	178,426	117,001	148,818
Gathering, marketing and processing	28,067	37,699	59,114
Electricity generation	53,137	47,788	50,846
Depreciation, depletion and amortization	390,544	308,103	308,586
Impairment of operating assets	5,368	9,885	31,937
Selling, general and administrative	100,125	61,852	54,907
Accretion of discount on asset retirement obligations	11,214	9,352	9,331
Interest	87,541	53,460	47,681
Deferred compensation adjustment	17,918	–	–
Loss on involuntary conversion of assets	1,000	1,000	–
Other expense (income), net	31,396	(9,033)	(5,036)
Total Costs and Expenses	1,218,063	838,043	867,821
Income Before Taxes	968,660	513,008	140,405
Income Tax Provision	322,940	199,158	50,513
Income From Continuing Operations	645,720	313,850	89,892
Discontinued Operations, Net of Tax	–	14,860	(6,061)
Cumulative Effect of Change in Accounting Principle, Net of Tax	–	–	(5,839)
Net Income	$ 645,720	$ 328,710	$ 77,992
Earnings Per Share:			
Basic –			
Income from continuing operations	$ 4.20	$ 2.69	$ 0.79
Discontinued operations, net of tax	–	0.13	(0.06)
Cumulative effect of change in accounting principle, net of tax	–	–	(0.05)
Net Income	$ 4.20	$ 2.82	$ 0.68
Diluted –			
Income from continuing operations	$ 4.12	$ 2.65	$ 0.78
Discontinued operations, net of tax	–	0.13	(0.05)
Cumulative effect of change in accounting principle, net of tax	–	–	(0.05)
Net Income	$ 4.12	$ 2.78	$ 0.68
Weighted average number of shares outstanding – Basic	153,773	116,550	113,928
Weighted average number of shares outstanding – Diluted	156,759	118,452	115,078

The accompanying notes are an integral part of these financial statements

Noble Energy, Inc. and Subsidiaries
Consolidated Statements of Cash Flows
(in thousands)

	Year ended December 31,		
	2005	2004	2003
Cash Flows from Operating Activities:			
Net income	$ 645,720	$ 328,710	$ 77,992
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization – oil and gas production	390,544	308,103	308,586
Depreciation, depletion and amortization – electricity generation	16,476	19,550	27,116
Dry hole expense	98,015	46,192	63,637
Impairment of operating assets	5,368	9,885	31,937
Amortization of unproved leasehold costs	17,855	19,280	33,380
Non-cash effect of discontinued operations	–	(14,996)	87,933
(Gain) loss on disposal of assets	(4,201)	(13,296)	17,978
Deferred income taxes	183,770	20,205	(31,475)
Accretion of discount on asset retirement obligations	11,214	9,352	9,331
Income from equity method investments	(90,812)	(78,199)	(45,186)
Dividends received from equity method investee	59,625	57,825	46,125
Deferred compensation adjustment	17,918	–	–
Loss on involuntary conversion of assets	1,000	1,000	–
Cumulative effect of change in accounting principle	–	–	5,839
Other	1,277	(21,422)	(12,063)
Changes in operating assets and liabilities, net of acquisition:			
Increase in accounts receivable	(73,940)	(99,886)	(62,406)
(Increase) decrease in other current assets	(53,560)	(13,305)	17,553
Increase in accounts payable	20,747	43,093	36,572
Increase (decrease) in other current liabilities	(7,138)	86,095	(10,079)
Net Cash Provided by Operating Activities	1,239,878	708,186	602,770
Cash Flows From Investing Activities:			
Additions to property, plant and equipment	(785,610)	(553,643)	(511,434)
Patina acquisition, net of cash acquired	(1,111,099)	–	–
Proceeds from sale of property, plant and equipment	13,179	62,455	81,084
Investments in equity method investees	(13,927)	(104,062)	(15,952)
Distribution from equity method investee	4,969	7,149	1,500
Net Cash Used in Investing Activities	(1,892,488)	(588,101)	(444,802)
Cash Flows From Financing Activities:			
Exercise of stock options	67,657	62,591	24,685
Cash dividends paid	(23,655)	(11,645)	(9,755)
Proceeds from credit facilities	3,335,333	375,000	285,000
Repayment of credit facilities	(2,140,333)	(619,753)	(334,825)
Repayment of Patina debt	(610,865)	–	–
Issuance of long-term debt		197,688	–
Proceeds from term loans	–	150,000	–
Repayment of term loans	(45,000)	–	–
Repayment of notes	–	(156,546)	(39,515)
Repayment of treasury stock obligation	–	–	(36,626)
Net Cash Provided by (Used in) Financing Activities	583,137	(2,665)	(111,036)
Increase (Decrease) in Cash and Cash Equivalents	(69,473)	117,420	46,932
Cash and Cash Equivalents at Beginning of Period	179,794	62,374	15,442
Cash and Cash Equivalents at End of Period	$ 110,321	$ 179,794	$ 62,374
Supplemental Disclosures of Cash Flow Information:			
Cash paid during the year for:			
Interest (net of amount capitalized)	$ 83,860	$ 38,468	$ 32,528
Income taxes paid	121,687	112,250	55,500
Non-cash financing and investing activities:			
Treasury stock and note obligation	–	–	36,626
Issuance of common stock and options and liabilities assumed in Patina Merger	3,783,306	–	–

The accompanying notes are an integral part of these financial statements

Noble Energy, Inc. and Subsidiaries
Consolidated Statements of Shareholders' Equity
(in thousands)

	Common Stock	Capital in Excess of Par Value	Deferred Compensation – Restricted Stock	Accumulated Other Comprehensive Income (Loss)	Treasury Stock at Cost	Retained Earnings	Total Shareholders' Equity
December 31, 2002	$399,116	$ 205,713	$ –	$ (14,603)	$ (39,330)	$ 458,490	$1,009,386
Net income	–	–	–	–	–	77,992	77,992
Exercise of stock options	5,844	18,841	–	–	–	–	24,685
Tax benefits related to exercise of stock options	–	4,174	–	–	–	–	4,174
Cash dividends ($.085 per share)	–	–	–	–	–	(9,755)	(9,755)
Unrealized hedge losses	–	–	–	(39,333)	–	–	(39,333)
Hedges reclassified to net income	–	–	–	43,843	–	–	43,843
Change in additional minimum pension liability and other	–	–	–	(793)	–	–	(793)
Treasury stock purchase	–	–	–	–	(36,626)	–	(36,626)
December 31, 2003	$404,960	$ 228,728	$ –	$ (10,886)	$ (75,956)	$ 526,727	$1,073,573
Net income	$ –	$ –	$ –	$ –	$ –	$ 328,710	$ 328,710
Exercise of stock options	11,910	50,681	–	–	–	–	62,591
Tax benefits related to exercise of stock options	–	9,791	–	–	–	–	9,791
Cash dividends ($.10 per share)	–	–	–	–	–	(11,645)	(11,645)
Issuance of restricted stock	282	2,258	(2,540)	–	–	–	–
Amortization of restricted stock	–	–	869	–	–	–	869
Unrealized hedge losses	–	–	–	(41,578)	–	–	(41,578)
Hedges reclassified to net income	–	–	–	40,188	–	–	40,188
Change in additional minimum pension liability and other	–	–	–	(2,511)	–	–	(2,511)
December 31, 2004	$417,152	$ 291,458	$(1,671)	$ (14,787)	$ (75,956)	$ 843,792	$1,459,988
Net income	$ –	$ –	$ –	$ –	$ –	$ 645,720	$ 645,720
Patina Merger	185,568	1,576,799	–	–	(73,203)	–	1,689,164
Exercise of stock options	13,013	54,644	–	–	–	–	67,657
Tax benefits related to exercise of stock options	–	15,407	–	–	–	–	15,407
Cash dividends ($0.15 per share)	–	–	–	–	–	(23,655)	(23,655)
Issuance of restricted stock	578	6,506	(7,084)	–	–	–	–
Amortization of restricted stock	–	–	3,467	–	–	–	3,467
Rabbi trust shares sold	–	90	–	–	683	–	773
Other	–	335	–	–	–	–	335
Unrealized hedge losses	–	–	–	(911,395)	–	–	(911,395)
Hedges reclassified to net income	–	–	–	154,992	–	–	154,992
Change in additional minimum pension liability and other	–	–	–	(12,309)	–	–	(12,309)
December 31, 2005	$616,311	$1,945,239	$(5,288)	$(783,499)	$(148,476)	$1,465,857	$3,090,144

The accompanying notes are an integral part of these financial statements

Noble Energy, Inc. and Subsidiaries
Consolidated Statements of Comprehensive Income (Loss)
(in thousands)

	Year ended December 31,		
	2005	2004	2003
Net income	$ 645,720	$328,710	$ 77,992
Other comprehensive income (loss):			
Unrealized loss on cash flow hedges:			
Oil and gas cash flow hedges	(1,402,147)	(60,248)	(56,652)
Less tax benefit	490,752	21,087	19,828
Interest rate lock cash flow hedge	–	(3,718)	(3,861)
Less tax benefit	–	1,301	1,352
Less reclassification adjustment for amounts out of OCI:			
Oil and gas cash flow hedges	237,692	61,292	67,451
Less tax provision	(83,192)	(21,452)	(23,608)
Interest rate lock cash flow hedge	757	535	–
Less tax provision	(265)	(187)	–
Change in additional minimum pension liability and other	(18,937)	(3,863)	(1,220)
Less tax provision	6,628	1,352	427
Other comprehensive income (loss)	(768,712)	(3,901)	3,717
Comprehensive income (loss)	$ (122,992)	$324,809	$ 81,709

The accompanying notes are an integral part of these 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

Noble Energy, Inc. (the "Company" or "Noble Energy") is an independent energy company engaged, directly or through its subsidiaries, in the exploration, development, production and marketing of crude oil and natural gas. The Company has exploration, exploitation and production operations domestically and internationally. Noble Energy operates throughout major basins in the United States including Colorado's Wattenberg field, the Mid-continent region of western Oklahoma and the Texas Panhandle, the San Juan basin in New Mexico, the Gulf Coast and the Gulf of Mexico. In addition, Noble Energy operates internationally, in Equatorial Guinea, the Mediterranean Sea, Ecuador, the North Sea, China, Argentina and Suriname.

Patina Merger – On May 16, 2005, Noble Energy completed a merger (the "Patina Merger") with Patina Oil & Gas Corporation ("Patina"), as set forth in the Agreement and Plan of Merger, dated as of December 15, 2004, as amended. Patina was an independent energy company engaged in the acquisition, development and exploitation of crude oil and natural gas properties within the continental United States. Patina's properties and oil and gas reserves are principally located in relatively long-lived fields with established production histories. The properties are primarily concentrated in the Wattenberg field of Colorado's Denver-Julesburg ("D-J") basin, the Mid-continent region of western Oklahoma and the Texas Panhandle, and the San Juan basin in New Mexico. See "Note 3 – Merger with Patina Oil & Gas Corporation."

Pending Purchase of U.S. Exploration Holdings, Inc. – In February 2006, Noble Energy announced that it had agreed to purchase the common stock of U.S. Exploration Holdings, Inc. ("U.S. Exploration"), a privately held corporation located in Billings, Montana, for $411.0 million. U.S. Exploration's reserves and production are located in the D-J basin's Wattenberg field. Subject to customary conditions, the transaction is scheduled to close on or before March 29, 2006. Prior to closing, U.S. Exploration will retire all company debt, terminate its commodity hedges and make all severance payments.

Note 2 – Summary of Significant Accounting Policies

Basis of Presentation and Consolidation

Accounting policies used by Noble Energy 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 and the consolidated accounts of its wholly-owned subsidiaries. The Company uses the equity method of accounting for investments in entities that it does not control but over which it exerts significant influence. Equity method investments are carried at Noble Energy's share of net assets plus loans and advances. Differences in the basis of the investment and the separate net asset value of the investee, if any, are amortized into income in accordance with the remaining useful life of the underlying assets. 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 amounts 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 and Denver offices perform all reserve estimates for the Company's different geographical regions. These reserve estimates are reviewed and approved by appropriate senior engineering staff and Division management with final approval by the Senior Vice President with responsibility for corporate reserves. See "Supplemental Oil and Gas Information."

Other items subject to estimates and assumptions include the carrying amounts of property, plant and equipment and goodwill; 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 significantly from those estimates.

Common Stock Split

On August 17, 2005, Noble Energy's Board of Directors approved a two-for-one split of its common stock that was effected in the form of a stock dividend. The stock dividend was distributed on September 14, 2005 to shareholders of record as of August 31, 2005. All share and per share data except par value have been adjusted to reflect the effect of the stock split for all periods presented.

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 at prevailing currency exchange rates. Transaction gains or losses were not material in any of the periods presented and are included in other expense (income), net 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.

Changes in the Company's allowance for doubtful accounts are as follows:

	Year ended December 31,		
	2005	**2004**	**2003**
	(in thousands)		
Balance at beginning of period	$13,093	$ 6,255	$1,510
Charged to expense	14,688	6,838	4,745
Deductions	(9,137)	–	–
Balance at end of period	$18,644	$13,093	$6,255

During 2005, the allowance was increased by $14.0 million to reflect additional collection allowances resulting from past due receivable amounts in Ecuador and $0.7 million due to various allowances related to the Company's domestic business. In addition, the allowance was decreased due to the final write-off of certain allowances recorded in prior years ($6.4 million) and partial recovery of certain amounts previously charged to expense ($2.7 million). During 2004, the allowance was increased by $5.4 million to reflect collection allowances related to Ecuador power operations and $1.4 million to record various provisions related to the Company's domestic business. During 2003, the allowance increased to reflect additional collection risk 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

Successful Efforts Method – 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 depreciation, depletion and amortization ("DD&A") are eliminated from the accounts and the resulting gain or loss is recognized. Repairs and maintenance are expensed as incurred.

Proved Properties – In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the Company reviews proved 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 estimated 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 $5.4 million of impairments in 2005, primarily related to downward reserve revisions on four domestic properties. 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 Gulf of Mexico property after recompletion and remediation activities produced less-than-expected results.

Unproved Properties – Individually significant unproved properties are also periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance. Cash flows used in the impairment analysis are determined based on management's estimates of crude oil and natural gas reserves, future commodity prices and future costs to extract the reserves. Cash flow estimates related to probable and possible reserves are reduced by additional risk-weighting factors. Other individually insignificant unproved properties are amortized on a composite method based on the Company's experience of successful drilling and average holding period. During 2005, the Company recorded impairments of individually significant unproved properties of $3.1 million in exploration expense.

Properties Acquired in Patina Merger – In determining the fair values of Patina's proved and unproved properties, the Company prepared estimates of crude oil and natural gas reserves. The Company estimated future prices to apply to the estimated reserve quantities acquired, and estimated future operating and development costs, to arrive at estimates of future net revenues. For the fair value assigned to proved reserves, the future net revenues were discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the merger. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net revenues of probable and possible reserves were reduced by additional risk-weighting factors.

Exploration Costs – 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. The Company will carry the costs of an exploratory well as an asset if the well found a sufficient quantity of reserves to justify its capitalization as a producing well and as long as the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. 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 access to necessary facilities and access to such permits and approvals and believes they will be obtained. Management assesses the status of its suspended exploratory well costs on a quarterly basis. See "Note 5 – Capitalized Exploratory Well Costs."

Other Property – 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.

Other Assets

Other assets consists of the following at December 31:

	2005	2004
	(in thousands)	
Probable insurance claims	$112,800	$ 84,832
Receivable related to derivative instruments	17,259	20,427
Marketable securities held by rabbi trust	39,676	–
Deferred loan fees	9,071	7,259
Intangible assets related to retirement plans	3,827	3,851
Other	37,743	27,755
Balance at end of period	$220,376	$144,124

Marketable securities and receivables related to derivative instruments are valued at current market value. Other assets are recorded at cost.

Goodwill

Goodwill represents the excess of the cost of an acquired entity over the net amounts assigned to assets acquired and liabilities assumed. The Company accounts for goodwill in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets." Goodwill is not amortized to earnings but is tested annually during the fourth quarter or whenever events or changes in circumstances indicate that the carrying value may not be recoverable.

Income Taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized when items of income and expense are recognized in the financial statements in different periods than when recognized in the tax return. Deferred tax assets arise when expenses are recognized in the financial statements before the tax returns or when income items are recognized in the tax return prior to the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Deferred tax liabilities arise when income items are recognized in the financial statements before the tax returns or when expenses are recognized in the tax return prior to the financial statements. 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.

Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair values 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 maturities.

The carrying amounts and estimated fair values of the Company's debt instruments, including current items as of December 31, for 2005 and 2004 were as follows.

	2005		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Long-term debt	$2,030,533	$2,097,060	$880,256	$963,319

Derivative Instruments – Derivative instruments are carried at fair market value on the balance sheet as determined by a professional valuation service firm. See "Note 12 – Derivative Instruments and Hedging Activities."

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. Interest is capitalized using an interest rate equivalent to the average rate paid on the Company's long-term debt. Capitalized interest is included in the cost of oil and gas assets and amortized with other costs on a unit-of-production basis. Capitalized interest totaled $8.7 million, $8.2 million and $13.4 million for 2005, 2004 and 2003, respectively.

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 common stock equivalents. The following table summarizes the calculation of basic EPS and diluted EPS components as of December 31:

	2005		2004		2003	
	Income	Shares	Income	Shares	Income	Shares
	(in thousands, except per share amounts)					
Net income available to common shareholders	$645,720	153,773	$328,710	116,550	$77,992	113,928
Basic EPS	$ 4.20		$ 2.82		$ 0.68	
Net income available to common shareholders	$645,720	153,773	$328,710	116,550	$77,992	113,928
Effect of dilutive stock options and restricted stock awards	–	2,986	–	1,902	–	1,150
Adjusted net income and shares	$645,720	156,759	$328,710	118,452	$77,992	115,078
Diluted EPS	$ 4.12		$ 2.78		$ 0.68	

The table below reflects the number of options excluded from the EPS calculation above for 2005 and 2003, 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.

	2005	2004	2003
Options excluded from dilution calculation	48,000	None	3,066,580
Range of exercise prices	$ 41.47		$18.82 - $21.61
Weighted average exercise price	$ 41.47		$20.55

A total of 2,168,980 shares of common stock of the Company held by a rabbi trust and accounted for as treasury stock were excluded from the 2005 EPS calculation above as they were antidilutive. See "Note 11 – Employee Benefit Plans."

Accounting for Share-Based Payments

At December 31, 2005, the Company had certain stock-based compensation plans, which are described more fully in "Note 9 – Stock Option and Restricted Stock Plans, Incentive Plan and Stockholder Rights." Through December 31, 2005, the Company accounted 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. When stock options were issued, 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 share-based payments.

	Year ended December 31, 2005	2004	2003
	(in thousands, except per share amounts)		
Net income, as reported	$645,720	$328,710	$77,992
Add: Stock-based compensation cost recognized, net of related tax effects	2,605	599	153
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(8,828)	(7,926)	(10,022)
Pro forma net income	$639,497	$321,383	$68,123
Earnings per share:			
Basic – as reported	$ 4.20	$ 2.82	$ 0.68
Basic – pro forma	4.16	2.76	0.60
Diluted – as reported	4.12	2.78	0.68
Diluted – pro forma	4.08	2.71	0.59

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 2005, 2004 and 2003 as follows:

	2005	2004	2003
Interest rate	4.55%	4.82%	5.07%
Dividend yield	0.37%	0.32%	0.38%
Expected volatility	21.53%	21.41%	28.38%
Expected life (in years)	9.15	9.58	9.42

The weighted average fair value of options granted using the Black-Scholes option-pricing model for 2005, 2004 and 2003 is as follows:

	2005	2004	2003
Black-Scholes model weighted-average fair value option price	$12.17	$9.27	$8.32

In December 2004, the Financial Accounting Standards Board ("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 January 1, 2006. The Company will adopt SFAS No. 123(R) as of January 1, 2006, using the modified prospective transition method. Under the modified prospective transition 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 January 1, 2006 will be accounted for in accordance with SFAS No. 123, except that the amounts will be recognized in the Company's consolidated statements of operations. Upon adoption of SFAS No. 123(R), the balance of deferred compensation related to restricted stock in the Company's shareholders' equity account will be reversed against capital in excess of par value in accordance with the transition requirements. Due to the complexity of developing a model to adequately value the Company's share-based payment awards, the Company has not yet quantified the impact of the new statement, but it is expected to increase compensation expense during 2006.

Treasury Stock

The Company follows the weighted-average cost method of accounting for treasury stock transactions. Amounts are recorded as a reduction in shareholders' equity.

Revenue Recognition and Imbalances

The Company records revenues from the sales of crude oil and natural gas 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 payable and is not recognized as revenue. Any amount of entitlement in excess of the amount sold by the Company is recognized as revenue and a receivable is accrued. The Company records the noncurrent portion of the payable in other deferred credits and noncurrent liabilities, and the current portion of the payable 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 payables were $34.6 million and $16.1 million at December 31, 2005 and 2004, respectively. The Company's imbalance receivables were $18.1 million and $21.2 million at December 31, 2005 and 2004, 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.

Noble Energy Marketing, Inc. ("NEMI"), a wholly-owned subsidiary, marketed approximately 55% of Noble Energy's domestic natural gas production in 2005. NEMI also engages in the purchase and sale of third-party crude oil and natural gas. The Company records third-party sales, net of cost of goods sold, as gathering, marketing and processing ("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 commodity price fluctuations. Such instruments include variable to fixed price swaps and costless collars. 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.

The Company accounts for its derivative instruments and hedging activities in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities, as amended," ("SFAS No. 133"). 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. SFAS No. 133 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 accumulated other comprehensive income (loss) ("AOCI") until the hedged item is recognized. Hedge accounting 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. Only derivative instruments that are expected to be highly effective in offsetting anticipated gains or losses on the hedged cash flows and that are subsequently documented to have been highly effective can qualify for hedge accounting. Any ineffectiveness in hedging instruments whereby gains or losses do not exactly offset anticipated gains or losses of hedged cash flows is recorded in earnings in the period in which the gain or loss occurs. Gains and losses from derivative instruments qualifying for hedge accounting treatment are deferred in AOCI and reclassified to oil and gas sales and royalties when the forecasted production occurs.

Related Party Transaction

Noble Energy entered into a consulting agreement with a former officer of Patina who now serves as a member of Noble Energy's Board of Directors. Pursuant to the consulting agreement the Board member serves as a consultant to the combined Company for a period of 12 months following the merger (May 16, 2005) in exchange for a monthly retainer of $50,000. The Company paid total consulting fees of $374,194 during 2005.

Legal Contingencies

The Company is subject to legal proceedings, claims and liabilities that arise in the ordinary course of business. The Company accrues for losses associated with the legal claims when such losses are considered probable and the amounts can be reasonably estimated.

Insurance

The Company maintains various types of insurance coverages as are customary in the industry that include directors and officers liability, general liability, well control, pollution, acts of terrorism, 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 $1.0 million of its general liability coverage.

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

Electricity Generation – Ecuador Integrated Power Project

The Company, through its subsidiaries, EDC Ecuador Ltd. and MachalaPower Cia. Ltda., has a 100% 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. See "Note 6 – Asset Retirement Obligations."

Concentration of Market Risk

Glencore Energy U.K., Ltd. ("Glencore") was the largest single non-affiliated purchaser of Noble Energy's 2005 production. Glencore is a purchaser of the Company's share of condensate from the Alba field in Equatorial Guinea. Sales to Glencore accounted for approximately 24% of 2005 crude oil sales, or approximately 11% of 2005 total oil and gas sales and royalties. No other single non-affiliated purchaser accounted for 10% or more of Noble Energy's 2005 oil and gas sales and royalties. During 2004, Marathon International Petroleum Supply Company (G.B.) Limited ("MIPSCO"), an affiliate of the operator of the Alba field in Equatorial Guinea, Marathon E. G. Production Ltd., accounted for 12% of oil and gas sales and royalties. During 2003, no single non-affiliated purchaser accounted for 10% or more of the Company's oil and gas sales and royalties. The Company believes the loss of any one purchaser would not have a material effect on the Company's financial position or results of operation since there are numerous potential purchasers of the Company's production.

Reclassification

Certain reclassifications have been made to the 2004 and 2003 consolidated financial statements to conform to the 2005 presentation. These reclassifications are not material to the Company's financial statements.

Note 3 – Merger with Patina Oil & Gas Corporation

On May 16, 2005, Noble Energy completed the Patina Merger and the results of Patina's operations since this date are included in the Company's consolidated statements of operations. Noble Energy acquired the common stock of Patina for a total purchase price of approximately $4.9 billion, which was comprised primarily of cash and Noble Energy common stock, plus liabilities assumed. In connection with the merger, Noble Energy issued 55.7 million shares of its common stock and paid $1.1 billion in cash to Patina shareholders. In addition, the Company repaid $610.9 million of Patina debt, including accrued interest, outstanding at the merger date and assumed deferred taxes of $1.1 billion. The common stock exchanged in the merger was valued at $29.77 per share based on the volume-weighted average prices of Noble Energy common stock during the five business days commencing two days before the terms of the merger were agreed to and announced. In addition, 7.8 million stock options held by Patina employees were converted into options for Noble Energy stock. The fair value of the vested options was $104.9 million, estimated using the Black-Scholes option-pricing model. The Company financed the cash consideration paid in the merger and the repayment of Patina debt through borrowings on its credit facilities, including a $1.3 billion acquisition credit facility. See "Note 7 – Debt." (The above amounts related to the number of shares issued, the value per share and the number of stock options issued have been adjusted for Noble Energy's two-for-one stock split, effected in the form of a stock dividend, in third quarter 2005.)

The Company considered the following strategic benefits of the merger, among others, in determining its offering price for the Patina net assets, which resulted in the recognition of goodwill:

- the merger establishes new core areas for Noble Energy in the Rocky Mountain and Mid-continent regions;
- the merger increases Noble Energy's proved reserves and production and lengthens Noble Energy's domestic reserve life;
- Patina's long-lived oil and gas reserves provide a significant inventory of low-risk opportunities that will balance Noble Energy's existing portfolio;
- Noble Energy expects to benefit from Patina's extensive tight gas sands technological and operational expertise that it gained in connection with the development of its Wattenberg field, particularly with respect to the development of Noble Energy's existing Rocky Mountain assets; and
- the combined company is significantly larger than Noble Energy was prior to the merger and, as a result, should have greater exploration and production strengths, greater liquidity in the market for its securities and additional future strategic opportunities that might not otherwise be possible.

Allocation of Purchase Price – The following table represents changes in the preliminary allocation of the total purchase price of Patina to the assets acquired and the liabilities assumed based on the fair values at the merger date. Certain data necessary to complete the Company's final purchase price allocation is not yet available, and includes, but is not limited to, final valuation of pre-acquisition contingencies (See "Note 14 – Commitments and Contingencies"), final tax returns that provide the underlying tax bases of Patina's assets and liabilities at May 16, 2005, and final appraisals of assets acquired and liabilities assumed. Certain adjustments have been made to previously-reported amounts allocated to assets acquired and liabilities assumed. The adjustments related to valuation of certain pre-acquisition contingencies and final appraisals of certain assets acquired and include the following:

	(in thousands)
Increase in deferred taxes and other non-current liabilities	$ 17,175
Increase in current assets	(5,300)
Increase in unproved oil and gas properties	(44,000)
Net decrease in goodwill	$(32,125)

The Company expects to complete its purchase price allocation during the twelve-month period following the acquisition date, during which time the preliminary allocation will be revised and goodwill will be adjusted, if necessary.

The following table sets forth Noble Energy's preliminary purchase price allocation:

	(in thousands, except stock price)
Shares of Noble Energy common stock issued to Patina shareholders	55,670
Average Noble Energy common stock price	$ 29.77
Fair value of common stock issued	$1,657,491
Cash consideration paid to Patina shareholders	1,098,078
Plus: fair value of Patina employee stock options exchanged for Noble Energy options	104,876
Plus: Noble Energy merger costs	13,347
Total purchase price paid	2,873,792
Plus: fair value of liabilities assumed by Noble Energy	
Current liabilities, excluding warrant obligation	88,096
Warrant obligation	16,840
Long-term debt, net of cash acquired	610,539
Deferred compensation liability (See "Note 11 – Employee Benefit Plans")	108,972
Asset retirement obligations	36,004
Other non-current liabilities	52,628
Deferred income taxes	1,107,861
Total purchase price plus liabilities assumed	$4,894,731
Fair value of Patina assets:	
Current assets	190,171
Proved oil and gas properties	2,642,000
Unproved oil and gas properties	1,068,000
Other non-current assets	46,532
Treasury stock held in deferred compensation plan (See "Note 11 – Employee Benefit Plans")	73,203
Goodwill	874,825
Total fair value of Patina assets	$4,894,731

Deferred Income Taxes – The amount allocated to deferred income taxes results from differences between the assigned values and the tax bases of the assets acquired and liabilities assumed in accordance with SFAS No. 109, "Accounting for Income Taxes." The Company is reviewing the historical deferred tax balances as well as the adjustment for the difference in book and tax basis for the fair value of the assets. Any future adjustments, if necessary, will be reflected as a final purchase price adjustment.

Goodwill – The preliminary allocation of purchase price included approximately $874.8 million of goodwill. The significant factors that contributed to the recognition of goodwill include, but are not limited to, economies of scale in connection with the Company's existing domestic operations, and the ability to acquire an established business with an assembled workforce with technological and operational expertise in tight gas sand formations. The goodwill was assigned to the Company's domestic reporting unit. In accordance with SFAS No. 142, "Goodwill and Other Intangible Assets", goodwill is not amortized to earnings but is tested, at least annually, for impairment at the reporting unit level. The Company conducted its goodwill impairment test as of December 31, 2005. Other events and changes in circumstances, such as a sale of domestic properties, may also require goodwill to be tested for impairment between annual measurement dates. If the carrying value of goodwill is determined to be impaired, the amount of goodwill is reduced and a corresponding charge is made to earnings in the period in which the goodwill is determined to be impaired. The Company does not expect the goodwill to be deductible for income tax purposes. No goodwill impairment was recognized as of December 31, 2005.

In accordance with Emerging Issues Task Force ("EITF") Abstract Issue No. 00-23, "Issues Related to the Accounting for Stock Compensation under APB Opinion No. 25 and FASB Interpretation No. 44", the Company has reduced the amount of goodwill originally recorded by $12.0 million for deferred tax assets associated with the exercise of fully-vested stock options assumed in conjunction with the Patina Merger to the extent that the stock-based compensation expense reported for tax purposes did not exceed the fair value of the awards recognized as part of the total purchase price.

Pro Forma Financial Information – The following pro forma condensed combined financial information for the years ended December 31, 2005 and 2004 was derived from the historical financial statements of Noble Energy and Patina and gives effect to the merger as if it had occurred on January 1, 2004. The pro forma condensed combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have occurred had the merger taken place as of the dates indicated and is not intended to be a projection of future results.

	Year ended December 31,	
	2005	**2004**
	(in thousands, except per share amounts)	
Revenues	$2,434,677	$1,913,786
Income from continuing operations	693,091	387,566
Net income	693,091	402,426
Earnings per share:		
Basic	$ 4.03	$ 2.38
Diluted	3.98	2.30

Note 4 – Effect of Gulf Coast Hurricanes

2005 Hurricane Activity – In August 2005 Hurricane Katrina moved through the Gulf of Mexico and caused the loss of the Main Pass 306D platform. The net book value of the platform was $14.5 million. Clean-up costs associated with the damage resulted in an increase to the Main Pass asset retirement obligation of $66.0 million. The Company has accounted for the net book value of the destroyed platform and the increase in asset retirement costs as a loss on involuntary conversion.

Main Pass clean-up and redevelopment costs are recoverable from insurance proceeds. However, the insurer has indicated that its maximum exposure limit has been reached and consequently the final insurance recovery will be limited. During third quarter 2005, the Company recorded a loss on involuntary conversion of $1.0 million with respect to the insurance deductible and a probable insurance claim of $13.5 million. In the fourth quarter 2005, the Company increased the Hurricane Katrina related probable insurance claim to $79.5 million, the estimated final recovery. Total costs for clean up and redevelopment are estimated at approximately $170.0 million.

Included in probable insurance claims at December 31, 2005 are expenditures for $10.0 million related to Hurricane Katrina clean-up. The Company believes this amount to be fully collectible; however, total reimbursement will likely occur beyond 2006 due to time required for the insurer to review all Hurricane Katrina related claims and determine the Company specific claim limitation on the final recovery.

Hurricane Rita struck the Gulf Coast in September 2005. Inspection of the Company's operated platforms indicated that there was no additional significant damage; however, damage to third party processing and pipeline facilities has slowed reinstatement of production. Expenditures for minor repairs amounted to $2.2 million through December 31, 2005. Subject to a $1.0 million deductible, the Company expects damages from Hurricane Rita to be fully recoverable.

2004 Hurricane Activity – In September 2004, Hurricane Ivan caused infrastructure damage at Main Pass 293/305/306. Costs related to clean-up and redevelopment including replacing the assets that were destroyed by Hurricane Ivan are expected to be recoverable from insurance proceeds, subject to a $1.0 million deductible. This amount was recognized as a loss on involuntary conversion of assets during 2004. The Company will adjust the total loss attributable to the involuntary conversion in the period in which the contingencies related to the replacement costs are resolved. The Company does not recognize a gain until collection of the insurance claim has been received. The remediation work began second quarter 2005, and the Company commenced production from undamaged platforms in third quarter 2005. However, damage to third party processing and pipeline facilities caused by Hurricanes Katrina and Rita has subsequently reduced production.

The Company has contracted a vessel and support services through 2006 to repair Company assets damaged by hurricanes in the Gulf of Mexico. The Company expects to spend $72.8 million in 2006 related to the vessel and support services with an option to extend the contract through 2007.

As of December 31, 2005, based upon work completed, Noble Energy has submitted $84.0 million (cumulative) in claims related to Hurricane Ivan damage, none of which has been disputed, and received $49.0 million (cumulative) in reimbursements. The Company received an additional $35.0 million in reimbursements in January 2006. Noble Energy expects to continue to incur costs, submit claims and receive reimbursements in the normal course of business in 2006 and beyond. In February 2006, the Company received insurance reimbursements of $6.4 million related to Hurricane Katrina damage.

The loss of production is not covered by business interruption insurance.

Amounts related to involuntary conversions caused by hurricane damage are as follows:

	Year ended December 31, 2005	2004
	(in thousands)	
Net book value of assets impaired or destroyed	$ 14,500	$ 23,978
Increase in asset retirement obligation related to hurricane damage	66,000	130,000
Loss on involuntary conversion of assets	80,500	153,978
Probable insurance claims	(79,500)	(152,978)
Net loss on involuntary conversion of assets	$ 1,000	$ 1,000

Assets (liabilities) related to the hurricane insurance recoveries and included in the Company's balance sheet consist of the following:

	December 31,	
	2005	2004
	(in thousands)	
Probable insurance claims – current	$ 142,311	$ 65,000
Other assets (long-term portion of probable insurance claims)	112,800	84,832
Total expected Ivan and Katrina insurance recoveries	$ 255,111	$ 149,832
Asset retirement obligations – current	$ (42,016)	$ (65,000)
Asset retirement obligations – long-term	(121,800)	(65,000)
Total asset retirement obligations related to Main Pass assets	$(163,816)	$(130,000)

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 is deemed noncommercial, in which case the well costs are immediately charged to exploration expense.

The following table reflects the Company's capitalized exploratory well activity and does not include amounts that were capitalized and subsequently expensed in the same period:

	Year ended December 31,		
	2005	2004	2003
	(in thousands)		
Capitalized exploratory well costs, beginning of period	$ 62,724	$ 29,375	$ 30,237
Additions to capitalized exploratory well costs pending determination of proved reserves	33,671	45,011	29,092
Reclassified to property, plant and equipment based on determination of proved reserves	(52,138)	(1,061)	(4,377)
Capitalized exploratory well costs charged to expense	(9,029)	(10,601)	(25,577)
Capitalized exploratory well costs, end of period	$ 35,228	$ 62,724	$ 29,375

The following table provides an aging of capitalized exploratory well costs (suspended well costs), as of December 31 of each year, based on the date the drilling was completed and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling:

	2005	2004	2003
	(in thousands)		
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$35,228	$44,986	$27,681
Capitalized exploratory well costs that have been capitalized for a period greater than one year	–	17,738	1,694
Balance at end of period	$35,228	$62,724	$29,375
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	–	4	4

The four projects as of December 31, 2004 that had exploratory costs greater than one year were reclassified to property, plant and equipment during 2005 when proved reserves were recorded.

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 of estimated costs for dismantlement, removal, site reclamation and similar activities associated with its oil and gas properties. An asset retirement obligation and the related asset retirement cost are recorded when an asset is first constructed or purchased. The asset retirement cost is determined and discounted to present value using a credit-adjusted risk-free rate. After initial recording the liability is increased for the passage of time, with the increase being reflected as accretion expense in the statement of operations. Subsequent adjustment in the cost estimate are reflected in the liability and the amounts continue to be amortized over the useful life of the related long-lived asset.

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.

As of December 31, 2005, the Company has no assets that are restricted for purposes of settling asset retirement obligations.

Changes in the Company's asset retirement obligations were as follows:

	Year ended December 31, 2005
	(in thousands)
Asset retirement obligations, beginning of period	$254,983
Fair value of Patina liabilities assumed	36,004
Liabilities incurred in current period	12,100
Liabilities incurred as a result of Hurricane Katrina	66,000
Liabilities settled in current period	(66,576)
Revisions	25,146
Accretion expense	11,214
Asset retirement obligations, end of period	$338,871
Current portion	$ 60,331
Noncurrent portion	278,540

Revisions during 2005 resulted from changes in estimated timing of actual abandonment and overall cost increases. The ending aggregate carrying amount at December 31, 2005 included $163.8 million related to hurricane damage. The Company expects to receive insurance reimbursements for this amount. See "Note 4 – Effect of Gulf Coast Hurricanes."

Note 7 – Debt

A summary of the Company's debt at December 31 follows:

	2005		2004	
	Debt	Interest Rate	Debt	Interest Rate
	(in thousands, except percentages)			
$2.1 billion Credit Agreement, due December 2010	$1,280,000	4.82	$ –	–
$1.3 billion Credit Agreement, due April 2010 (terminated)	–	–	–	–
$400 million Credit Agreement, due October 2009 (terminated)	–	–	85,000	2.86
$400 million Credit Agreement, due November 2006 (terminated)	–	–	–	–
5¼% Senior Notes, due April 2014	200,000	5.25	200,000	5.25
7¼% Notes, due October 2023	100,000	7.25	100,000	7.25
8% Senior Notes, due April 2027	250,000	8.00	250,000	8.00
7¼% Senior Debentures, due August 2097	100,000	7.25	100,000	7.25
Term Loans, due January 2009	105,000	5.23	150,000	3.00
Outstanding debt	2,035,000		885,000	
Unamortized discount	(4,467)		(4,744)	
Long-term debt	$2,030,533		$880,256	

The Company's total long-term debt, net of unamortized discount, at December 31, 2005, was $2.031 billion compared to $880.3 million at December 31, 2004. The ratio of debt-to-book capital (defined as the Company's total debt divided by the sum of total debt plus equity) was 40% at December 31, 2005, compared with 38% at December 31, 2004.

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 7¼% Notes, the 8% Senior Notes and the 7¼% 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.

Credit Facilities

$2.1 Billion Credit Facility Due December 2010 – On December 9, 2005, Noble Energy entered into a new $2.1 billion unsecured five-year revolving credit facility (the "New Facility"). The New Facility was entered into among the Company and certain commercial lending institutions. On that same date, the Company drew down on the New Facility and repaid and terminated its existing credit facilities, which consisted of a $400 million credit agreement due October 2009, a $400 million credit agreement due November 2006, and a $1.3 billion credit agreement due April 2010.

The New Facility is available to refinance existing indebtedness of the Company, and for general corporate purposes. Interest rates are based upon a Eurodollar rate plus a range of 20.0 basis points to 95.0 basis points depending upon the Company's credit rating and utilization of the New Facility. The New Facility has facility fees that range from 7.5 basis points to 17.5 basis points depending upon the Company's credit rating. The New Facility contains customary representations and warranties and affirmative and negative covenants, including, but not limited to, the following financial covenants: (a) the ratio of Earnings Before Interest, Taxes, Depreciation and Exploration Expense 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; and (b) the total debt to capitalization ratio, expressed as a percentage, may not exceed 60% at any time. A violation of these covenants could result in a default under the New Facility, which could permit the participating banks to restrict the Company's ability to access the New Facility and require the immediate repayment of any outstanding advances under the New Facility.

Certain lenders that are a party to the New Facility have in the past performed, and may in the future from time to time perform, investment banking, financial advisory, lending or commercial banking services for the Company and its subsidiaries, for which they have received, and may in the future receive, customary compensation and reimbursement of expenses. The Company incurred debt issuance costs of $1.0 million in connection with the New Facility. These costs will be amortized to expense over the life of the New Facility.

$1.3 Billion Credit Facility Due April 2010 – Noble Energy incurred approximately $1.7 billion of indebtedness in the Patina Merger, primarily to fund the cash consideration, repay Patina's debt, and fund merger costs. In connection with the merger, the Company entered into a $1.3 billion credit facility (the "Acquisition Facility") with certain financial institutions. The Acquisition Facility was entered into (a) to provide the Company with funds necessary to complete its acquisition of Patina, (b) to refinance existing indebtedness of the Company and Patina, and (c) for general corporate purposes. The Acquisition Facility was a reducing revolver due 2010 with a 5% per quarter commitment reduction in each quarter during year four of the facility and a 20% per quarter commitment reduction in each quarter during year five of the facility. The Acquisition Facility incurred a 7.5 basis point standby commitment fee, totaling $0.1 million, from the effective date, April 4, 2005, until the initial borrowing date under the facility, May 16, 2005. Commencing on May 16, 2005, the Company incurred a facility fee of 10 to 25 basis points per annum (15 basis points at the time of repayment) depending upon the Company's credit rating. The Acquisition Facility bore interest based upon a Eurodollar rate plus 30 to 100 basis points (60 basis points at the time of repayment) depending upon the Company's credit rating. The Company incurred debt issuance costs of $2.4 million in connection with the Acquisition Facility. In December 2005 the Acquisition Facility was repaid with proceeds from the New Facility and the Acquisition Facility was terminated. Unamortized acquisition costs of $2.1 million on the Acquisition Facility were added to the acquisition costs of the New Facility in accordance with EITF 98-14, "Debtor's Accounting for Changes in Line-of-Credit or Revolving-Debt Arrangements."

$400 Million Credit Facility Due October 2009 – In October 2004, the Company entered into a $400 million credit facility due October 2009 (the "2004 Facility"). The 2004 Facility was with certain commercial lending institutions and was available for general corporate purposes. The 2004 Facility bore 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 was payable periodically based on the tenor of the underlying Eurodollar rate selected at the time of drawing. In December 2005 the 2004 Facility was repaid with proceeds from the New Facility and the 2004 Facility was terminated.

$400 Million Credit Facility Due November 2006 – In November 2001, the Company entered into a $400 million credit facility due November 2006 (the "2001 Facility"). The 2001 Facility was with certain commercial lending institutions and was available for general corporate purposes. The 2001 Facility bore 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 was payable periodically based on the tenor of the underlying Eurodollar rate selected at the time of drawing. In December 2005 the 2001 Facility was terminated and replaced by the new $2.1 billion facility.

No early termination penalties were incurred by the Company as a result of the termination of the three credit facilities.

Term Loans

During 2004, a subsidiary of the Company, Noble Energy Mediterranean Ltd., entered into term loan agreements (the "Term Loans") with several commercial lending institutions for a total of $150 million. The interest rates on the Term Loans 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 a rate reset. The Term Loans expire in January 2009. Proceeds were used to reduce amounts outstanding under credit agreements. In 2005, the Company prepaid $45.0 million of the Term Loans.

Issuance of Public Debt

During April 2004, the Company closed an offering of $200 million senior unsecured notes (the "Senior Notes") receiving net proceeds of approximately $197.7 million, after deducting underwriting discounts and expenses. The Senior Notes mature April 15, 2014 and pay interest semi-annually at 5¼%. The net proceeds from the offering were used to repay amounts outstanding under existing credit agreements and for general corporate purposes. The Company may redeem the Senior 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 Senior 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 Senior Notes. 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 AOCI was $4.1 million, net of tax, and $4.6 million, net of tax, at December 31, 2005 and 2004, respectively. This amount is being reclassified into earnings as adjustments to interest expense over the term of the Senior Notes.

Annual Maturities

The Company's annual maturities of outstanding debt as of December 31, 2005 are as follows:

	(in thousands)
2006	$ –
2007	–
2008	–
2009	105,000
2010	1,280,000
Thereafter	650,000
Total	$2,035,000

<u>Note 8– Income Taxes</u>

The components of income before income taxes are as follows:

	Year ended December 31,		
	2005	2004	2003
	(in thousands)		
Domestic	$426,756	$254,582	$ 56,068
Foreign	541,904	258,426	84,337
Total	$968,660	$513,008	$140,405

The income tax provision consists of the following:

	Year ended December 31, 2005	2004	2003
	(in thousands)		
Current taxes:			
Federal	$ 48,293	$136,858	$ 45,985
State	–	6,930	1,867
Foreign	90,877	39,624	32,341
Total current	139,170	183,412	80,193
Deferred taxes:			
Federal	119,953	1,192	(31,087)
State	14,073	(702)	(1,084)
Foreign	49,744	23,258	(773)
Total deferred	183,770	23,748	(32,944)
Total income tax provision	$322,940	$207,160	$ 47,249
Income tax provision associated with continuing operations	$322,940	$199,158	$ 50,513
Income tax provision associated with discontinued operations	–	8,002	(3,264)
Total income tax provision	$322,940	$207,160	$ 47,249

A reconciliation of the federal statutory tax rate to the effective tax rate is as follows:

	Year ended December 31, 2005	2004	2003
	(amounts in percentages)		
Federal statutory rate	35.0	35.0	35.0
Effect of:			
State taxes, net of federal benefit	1.3	0.7	0.4
Difference between U.S. and foreign rates	0.3	5.6	14.1
AJCA repatriation benefit	(3.7)	–	–
Write-off of Vietnam investment	–	–	(11.5)
Release of China valuation allowance	–	(2.7)	–
Other, net	0.4	0.2	(2.0)
Effective rate	33.3	38.8	36.0

Deferred tax assets and liabilities resulted from the following:

	December 31, 2005	December 31, 2004
	(in thousands)	
Deferred tax assets:		
Foreign loss carryforward	$ 3,431	$ 22,350
Foreign and state income tax accruals	8,884	12,991
Accrued expenses	39,636	7,846
Deferred income	1,916	3,359
Allowance for doubtful accounts	3,152	8,758
Fair value of derivative contracts	448,240	8,180
Postretirement benefits	23,011	8,808
Reclass to income taxes	–	6,570
Deferred compensation	43,567	–
Foreign tax credits	5,598	–
Future foreign tax credits from foreign branch deferred tax liabilities	54,882	–
Other	1,067	–
Total deferred tax assets	633,384	78,862
Valuation allowance	(48,386)	–
Net deferred tax assets	584,998	78,862
Deferred tax liabilities:		
Property, plant and equipment, principally due to differences in depreciation, amortization, lease impairment and abandonments	1,546,062	240,438
Fair value of derivative contracts	–	3,611
Other	3,082	2,189
Total deferred tax liability	1,549,144	246,238
Net deferred tax asset (liability)	$ (964,146)	$(167,376)

Net deferred tax liabilities were classified in the consolidated balance sheet as follows:

	December 31, 2005	December 31, 2004
	(in thousands)	
Assets:		
Deferred taxes	$ 237,045	$ 13,039
Liabilities:		
Deferred income taxes	(1,201,191)	(180,415)
Net deferred tax asset (liability)	$ (964,146)	$(167,376)

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, 2005. The amount of the deferred tax asset considered realizable could be reduced in the future 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 decreased from $22.3 million in 2004 to $3.4 million in 2005. The foreign loss carryforward related to China was fully utilized in 2005. However, the Company incurred losses on its project in Suriname and on other new venture activities which are not yet commercial. Therefore, a valuation allowance of $3.4 million was provided against the tax benefits of those losses. The Company has determined that it will be able to claim a foreign tax credit for U.S. federal income tax purposes in 2005 and expects to be in a credit position for the next several years. Therefore, the Company has recorded a deferred tax asset for certain foreign taxes paid in 2005 that cannot be claimed as a credit in that year because of limitations imposed by the Internal Revenue Code. A valuation allowance of $3.6 million has been provided against this deferred tax asset. The Company has also recorded a deferred tax asset of $54.9 million for the future foreign tax credits associated with deferred tax liabilities recorded by its foreign branch operations. A valuation allowance of $41.4 million has been provided against the deferred tax asset.

American Jobs Creation Act of 2004 – On October 22, 2004, the American Jobs Creation Act ("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 grant a special deduction that, depending on the circumstances, could reduce the effective tax rate. In accordance with FASB Staff Position 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," the Company has accounted for any qualified production activities deduction as a special deduction in 2005. The deduction did not have a significant impact on the Company's income tax provision or deferred tax assets or liabilities in 2005.

The AJCA also created a temporary incentive for U.S. corporations to repatriate accumulated income earned abroad by providing for an 85% dividends-received deduction for certain dividends from controlled foreign corporations. In July 2005, the Company completed its evaluation of the effects of the repatriation provision, and the Company's Board of Directors approved a plan to repatriate $118.0 million in earnings of the Company's methanol subsidiary during third quarter 2005. Because the Company has provided U.S. tax on most of the methanol subsidiary's earnings at 35% through December 31, 2004, repatriation under the Act resulted in a net tax benefit of $35.1 million recorded in third quarter 2005.

The Company has not recorded U.S. deferred income taxes on the remaining undistributed earnings of its foreign subsidiaries as of December 31, 2005. As of December 31, 2005, the accumulated undistributed earnings of the consolidated foreign subsidiaries were approximately $325.0 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. Although the Company is claiming foreign tax credits in 2005, it may not be in a credit position when any future remittance of foreign earnings takes place.

Note 9 – Stock Option and Restricted Stock Plans, Incentive Plan and Stockholder Rights

The Company's stock option and restricted stock plans and incentive plan are described below. The numbers of shares of common stock, restricted stock and options have been adjusted to reflect the Company's two-for-one stock split, effected in the form of a stock dividend, in third quarter 2005.

1992 Stock Option and Restricted Stock Plan – Under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, as amended (the "1992 Plan"), the Compensation, Benefits and Stock Option Committee of the Board of Directors (the "Committee") may grant stock options and award restricted stock to officers or other employees of the Company and its subsidiaries. Stock options are issued with an exercise price equal to the market price of Noble Energy common stock on the date of grant, and are subject to such other terms and conditions as may be determined by the Committee. Unless granted by the Committee for a shorter term, the options expire ten years from the grant date. The maximum number of shares of common stock that may be issued under the 1992 Plan is 18,500,000 shares. Restricted stock awards made under the 1992 Plan are subject to such restrictions, terms and conditions, including forfeitures, if any, as may be determined by the Committee. At December 31, 2005, the Company had reserved 9,129,300 shares of common stock for issuance, including 5,232,008 shares available for future grants and awards, under the 1992 Plan.

2004 Long-Term Incentive Plan – Under the Noble Energy, Inc. 2004 Long-Term Incentive Plan (the "2004 LTIP"), the Committee may make incentive awards to key employees of the Company and its subsidiaries. Incentive compensation is based upon the attainment of specific performance goals established by the Committee. Awards may be in the form of stock options or restricted stock 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 Committee in its discretion. Stock options granted and restricted stock awarded under the 2004 LTIP are granted and awarded pursuant to the terms of the 1992 Plan.

2005 Stock Plan for Non-Employee Directors – The 2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (the "2005 Plan") was approved by shareholder vote on April 26, 2005. The 2005 Plan provides for grants of stock options and awards of restricted stock to non-employee directors of the Company. The 2005 Plan provides for the granting of 11,200 stock options on the date of election to the Board of Directors, annual grants of 2,800 options on February 1 of each year, and discretionary grants by the Board of Directors (up to a maximum of 11,200 options granted in any one year). Options are issued with an exercise price equal to the market price of Noble Energy common stock on the date of grant and may be exercised one year after the date of grant. The options expire ten years from the grant date. The 2005 Plan also provides for the granting of 4,800 shares of restricted stock on the date of election to the Board of Directors, annual awards of 1,200 shares of restricted stock on February 1 of each year, and discretionary grants by the Board of Directors (up to a maximum of 4,800 shares of restricted stock awarded in any one year). Restricted stock is restricted for a period of at least one year from the date of grant. The 2005 Plan superseded and replaced the 1988 Nonqualified Stock Option Plan for Non-Employee Directors. The total number of shares of common stock that may be issued under the 2005 Plan is 800,000. At December 31, 2005, the Company had reserved 800,000 shares of common stock for issuance, including 752,000 shares available for future grants under the 2005 Plan.

1988 Nonqualified Stock Option Plan – The 1988 Nonqualified Stock Option Plan for Non-Employee Directors of Noble Energy, Inc., as amended, (the "1988 Plan") provided for the issuance of stock options to non-employee directors of the Company. The options may be exercised one year after grant and expire ten years from the grant date. The 1988 Plan provided for the granting of a fixed 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) on February 1 of each year. The 1988 Plan was terminated in 2005.

Patina Stock Option Plans – Patina maintained a shareholder approved stock option plan for employees (the "Patina Employee Plan") that provided for the issuance of options at prices not less than fair market value at the date of grant. Patina also maintained a shareholder approved stock grant and option plan for non-employee directors (the "Patina Directors' Plan"). The Patina Directors' Plan provided for stock options to be granted to each non-employee director upon appointment and upon annual re-election thereafter. Upon completion of the Patina Merger, all unvested stock options outstanding under the Patina Employee Plan and the Patina Directors' Plan became fully vested, and all outstanding options were converted into options to purchase for Noble Energy common stock. The Patina options expire five years from the date of grant. See "Note 3 – Merger with Patina Oil & Gas Corporation."

A summary of the status of Noble Energy's stock option plans is presented below:

	Options Outstanding		Options Exercisable	
	Number Outstanding	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
Outstanding at December 31, 2002	8,386,442	$16.69	5,743,886	$16.42
Options granted	1,517,800	17.71		
Options exercised	(1,753,032)	14.08		
Options canceled	(213,122)	18.48		
Outstanding at December 31, 2003	7,938,088	$17.42	5,284,154	$17.20
Options granted	650,070	22.22		
Options exercised	(3,573,286)	17.52		
Options canceled	(248,390)	17.86		
Outstanding at December 31, 2004	4,766,482	$17.66	2,985,650	$17.38
Options granted	797,858	30.92		
Options issued in Patina merger	7,802,968	17.93		
Options exercised	(3,903,889)	17.33		
Options canceled	(143,777)	24.25		
Outstanding at December 31, 2005	9,319,642	$19.21	7,881,163	$18.05

The following table summarizes information about the Company's stock options, which were outstanding and those that were exercisable as of December 31, 2005:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Life (in years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$ 4.14 - $10.44	1,675,882	1.2	$ 7.24	1,675,882	$ 7.24
10.45 - 16.59	1,863,941	3.3	12.95	1,863,941	12.95
16.60 - 20.73	1,423,020	5.3	18.16	1,054,785	18.33
20.74 - 25.72	2,125,557	4.7	21.73	1,790,029	21.63
25.73 - 30.86	621,566	9.1	29.86	–	–
30.87 - 41.47	1,609,676	4.5	32.41	1,496,526	32.04
$ 4.14 - $41.47	9,319,642	4.1	$19.21	7,881,163	$18.05

Income tax benefits associated with the exercise of stock options of $15.4 million, $9.8 million and $4.2 million for the years ended December 31, 2005, 2004 and 2003, respectively, were credited to additional paid in capital. In addition, $12.0 million of income tax benefits related to the exercise of fully-vested options assumed in the Patina Merger reduced goodwill.

The following table reflects outstanding restricted stock awards as of December 31, 2005 and 2004 and activity related thereto. No restricted stock awards were granted during 2003.

	Year ended December 31,			
	2005		2004	
	Subject to Time Vesting	Subject to Performance Conditions	Subject to Time Vesting	Subject to Performance Conditions
	(shares)			
Restricted Stock:				
Outstanding beginning of year	–	82,382	–	–
Restricted stock granted	125,560	64,870	–	84,590
Restricted stock forfeited	(2,314)	(13,737)	–	(2,208)
Outstanding end of year	123,246	133,515	–	82,382

The weighted average grant date fair value of restricted stock granted in 2005 and 2004 was $32.82 per share and $22.12 per share, respectively. When restricted stock is granted, unearned compensation related to the restricted shares is charged to deferred compensation as a reduction in shareholders' equity. When restricted stock is granted subject to time vesting, compensation expense is recognized over the vesting period. When restricted stock is granted subject to performance conditions, compensation expense is recognized over 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 years ended December 31, 2005 and 2004, the Company's compensation expense included $3.5 million and $0.9 million, respectively, related to restricted stock awards.

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% 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 – Additional Shareholders' Equity Information

The following table reflects the activity in shares (as adjusted for the two-for-one stock split, effected in the form of a stock dividend, in third quarter 2005) of the Company's common stock and treasury stock:

	Year Ended December 31, 2005	2004
Common Stock Outstanding:		
Shares at beginning of period	125,144,834	121,489,166
Shares issued in Patina acquisition	55,670,408	–
Exercise of common stock options	3,903,889	3,573,286
Restricted stock grants, net of forfeitures	174,379	82,382
Shares at end of period	184,893,510	125,144,834
Treasury Stock Outstanding:		
Shares at beginning of period	7,099,952	7,099,952
Shares issued in Patina acquisition	2,189,414	–
Rabbi trust shares sold	(20,434)	–
Shares at end of period	9,268,932	7,099,952

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

	December 31, 2005	2004
	(in thousands)	
Deferred net loss on oil and gas cash flow hedges, net of tax	$(763,834)	$ (6,939)
Deferred net loss on interest rate cash flow hedge, net of tax	(4,085)	(4,577)
Minimum pension liability and other, net of tax	(15,580)	(3,271)
Accumulated other comprehensive loss	$(783,499)	$(14,787)

Note 11 – Employee Benefit Plans

Pension Plan and Other Postretirement Benefit Plans

The Company has a noncontributory, tax-qualified defined benefit pension plan covering certain 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'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 also has an unfunded, nonqualified restoration plan that provides the pension plan formula benefits that cannot be provided by the pension plan because of the compensation and benefit limitations imposed on the pension plan by federal tax laws. 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, restoration and other postretirement benefit plans at December 31:

	Retirement and Restoration Plan Benefits		Medical and Life Plan Benefits	
	2005	2004	2005	2004
	(in thousands)			
Change in benefit obligation				
Benefit obligation at beginning of year	$132,746	$118,270	$ 11,715	$ 9,156
Service cost	6,372	6,248	963	610
Interest cost	7,807	7,303	943	577
Amendments	614	470	–	(1,036)
Employee contributions	–	–	223	177
Actuarial loss	26,158	5,536	14,113	2,809
Benefits paid	(5,396)	(5,081)	(734)	(578)
Benefit obligation at end of year	$168,301	$132,746	$ 27,223	$ 11,715
Change in plan assets				
Fair value of plan assets at beginning of year	81,115	74,025	–	–
Actual return on plan assets	5,725	7,919	–	–
Employer contributions	13,388	4,252	511	401
Employee contributions	–	–	223	177
Benefits paid	(5,396)	(5,081)	(734)	(578)
Fair value of plan assets at end of year	$ 94,832	$ 81,115	$ –	$ –
Funded status	(73,469)	(51,631)	(27,223)	(11,715)
Unrecognized net actuarial loss	56,144	29,650	20,754	7,401
Unrecognized prior service cost (benefit)	2,734	2,518	(1,399)	(1,636)
Unrecognized net transition obligation	1,093	1,118	–	–
Net amount recognized	$(13,498)	$(18,345)	$ (7,868)	$ (5,950)
Net amount recognized in statement of financial postion consists of:				
Accrued benefit costs	(43,679)	(26,912)	(7,868)	(5,950)
Intangible assets	3,827	3,851	–	–
Accumulated other comprehensive loss	26,354	4,716	–	–
Net amount recognized	$(13,498)	$(18,345)	$ (7,868)	$ (5,950)

The accumulated benefit obligation for the defined benefit pension plan and restoration plan was $138.5 million and $108.0 million at December 31, 2005 and 2004, respectively.

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

	Retirement and Restoration Plan Benefits			Medical and Life Plan Benefits		
	2005	2004	2003	2005	2004	2003
	(in thousands)					
Service cost	$ 6,372	$ 6,248	$ 5,271	$ 963	$ 610	$ 534
Interest cost	7,807	7,303	6,772	943	577	524
Expected return on plan assets	(7,094)	(6,745)	(5,857)	–	–	–
Transition obligation recognition	24	25	24	–	–	–
Amortization of prior service cost	398	353	319	(236)	(236)	(110)
Recognized net actuarial loss	1,034	560	158	760	363	272
Net periodic benefit cost	$ 8,541	$ 7,744	$ 6,687	$2,430	$1,314	$1,220
Additional Information						
Increase in minimum liability included in other comprehensive income	$21,638	$ 4,716				
Weighted-average assumptions used to determine benefit obligations at December 31,						
Discount rate	5.50%	6.00%	6.25%	5.50%	5.75%	6.25%
Rate of compensation increase	5.00%	4.00%	4.00%	–	–	–
Weighted-average assumptions used to determine net periodic benefit costs for year ended December 31,						
Discount rate	6.00%	6.25%	6.75%	5.75%	6.25%	6.75%
Expected long-term return on plan assets	8.25%	8.50%	8.50%	–	–	–
Rate of compensation increase	4.00%	4.00%	4.00%	–	–	–

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 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. The Company assumes its long-term asset mix will be consistent with its target asset allocation of 70% equity and 30% fixed income, with a range of plus or minus 10% 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% per annum over the life of the plan.

Assumed health care cost trend rates were as follows at December 31:

	2005	2004
Health care cost trend rate assumed for next year	10%	10%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate)	5%	5%
Year rate reaches ultimate trend rate	2011	2010

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 effects:

	1% Increase	1% Decrease
	(in thousands)	
Effect on total service and interest cost components for 2005	$ 274	$ (233)
Effect on year-end 2005 postretirement benefit obligation	3,878	(3,325)

The following table reflects weighted-average asset allocations by asset category for the Company's tax-qualified defined benefit pension plan:

	Target Allocation	Plan Assets	
	2006	2005	2004
Asset category			
Equity securities	70%	73%	72%
Fixed income	30%	27%	28%
Other	–	–	–
Total	100%	100%	100%

The investment policy for the tax-qualified 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 1% decrease in the expected return on plan assets would have resulted in an increase in benefit expense of $0.9 million in 2005.

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, 2005, the Company had cumulative asset losses of approximately $3.4 million, which remain to be recognized in the calculation of the market-related value of assets.

Contributions

The Company contributed cash of $13.9 million to its tax-qualified defined benefit pension, restoration and other postretirement benefit plans during 2005. The Company expects to make additional cash contributions of $7.2 million during 2006 (unaudited).

Estimated Future Benefit Payments

As of December 31, 2005, the following future benefit payments are expected to be paid:

	Retirement and Restoration Plan Benefits	Medical and Life Plan Benefits
	(in thousands)	
2006	$ 6,073	$ 786
2007	6,824	937
2008	7,106	1,088
2009	7,445	1,255
2010	8,511	1,402
Years 2011 to 2015	57,932	12,907

The estimate of expected future benefit payments is based on the same assumptions used to measure the Company's benefit obligation at December 31, 2005 and includes estimated future employee service.

401(k) Plans

The Company sponsors 401(k) savings plans. Participation is voluntary and all regular employees are eligible to participate. The Company makes contributions to match certain employee contributions. In addition, the Company may make discretionary profit sharing contributions. The Company made cash contributions of $4.5 million, $2.4 million and $2.4 million in 2005, 2004 and 2003, respectively.

Deferred Compensation Plan

In connection with the Patina Merger, the Company acquired the assets and assumed the liabilities related to a Patina shareholder-approved non-qualified deferred compensation plan. This plan was available to officers and certain managers of Patina and allowed participants to defer all or a portion of their salary and annual bonuses (either in cash or common stock). Participant-directed investments are held in a rabbi trust and are available to satisfy the claims of the Company's creditors in the event of bankruptcy or insolvency. Participants may elect to receive distributions in either cash or shares of Noble Energy common stock. At December 31, 2005, the assets in the rabbi trust totaled $127.1 million, including 2,168,980 shares of common stock of Noble Energy valued at $87.4 million. The Company accounts for the deferred compensation plan in accordance with EITF 97-14, "Accounting for Deferred Compensation Arrangements Where Amounts Earned are Held in a Rabbi Trust and Invested."

Assets of the rabbi trust, other than common stock of the Company, are invested in certain mutual funds that cover an investment spectrum ranging from equities to money market instruments. These mutual funds are publicly quoted and reported at market value. The Company accounts for these investments in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." The Company's common stock held by the rabbi trust at December 31, 2005 has been classified as treasury stock in the shareholders' equity section of the accompanying consolidated balance sheets. The market value of the assets held by the rabbi trust, exclusive of the market value of the shares of the Company's common stock that are reflected as treasury stock, at December 31, 2005 was $39.7 million, and is included in other assets in the accompanying consolidated balance sheets. The amounts payable to the plan participants at December 31, 2005, including the market value of the shares of the Company's common stock that are reflected as treasury stock, total $127.1 million, and are included in deferred compensation liability in the accompanying consolidated balance sheets. Approximately 2,060,000 shares or 95% of the common stock held in the plan at December 31, 2005 were attributable to a member of the Company's Board of Directors. Since May 16, 2005, plan participants have sold investments in 20,434 shares of Noble Energy common stock in the rabbi trust and invested the proceeds in mutual funds.

In accordance with EITF 97-14, all fluctuations in market value of the rabbi trust assets have been reflected in the accompanying consolidated statements of operations. Increases or decreases in the value of the rabbi trust assets, exclusive of the shares of common stock of the Company, have been included in other expense (income), net in the accompanying consolidated statements of operations. This amount totaled $2.9 million from acquisition date through December 31, 2005. Increases or decreases in the market value of the deferred compensation liability, including the shares of common stock of the Company held by the rabbi trust, while recorded as treasury stock, are included as deferred compensation adjustments in the accompanying consolidated statements of operations. Based on the changes in the total market value of the rabbi trust assets, the Company recorded deferred compensation adjustments of $17.9 million from acquisition date through December 31, 2005.

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 variable to fixed price swaps and costless collars. 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 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.

It if becomes probable that the hedging instrument is no longer highly effective, the hedging instrument loses hedge accounting treatment. All current mark-to-market gains and losses are recorded in earnings and all accumulated gains or losses recorded in AOCI related to the hedging instrument are also reclassified to earnings. As a result of the impacts of Hurricanes Katrina and Rita on the timing of the Company's forecasted production during the fourth quarter of 2005, derivative instruments hedging approximately 6,000 barrels per day of crude oil and 40,000 MMBtu per day of natural gas, no longer qualified for hedge accounting. Accordingly, beginning October 1, 2005 the changes in fair value of these derivative contracts were recognized in the Company's results of operations, causing a mark-to-market gain of $20.0 million ($13.0 million, net of tax). In addition, the delay in the timing of the Company's production resulted in a loss of $51.8 million in fourth quarter 2005 ($33.7 million, net of tax) related to amounts previously recorded in AOCI. Both the gain and the loss are included in other expense (income) on the statement of operations. No gains or losses were reclassified from AOCI into earnings as a result of the discontinuance of hedge accounting treatment during 2004 or 2003. During 2004 and 2003, the Company's ineffectiveness related to its cash flow hedges was *de minimis*.

During 2005, 2004 and 2003, the Company entered into various NYMEX and Brent costless collars related to its crude oil and natural gas production. The tables below summarize the various transactions:

	2005	2004	2003
Natural Gas Collars:			
NYMEX –			
Hedge MMBtupd	79,932	120,284	190,038
Floor price range	$5.00 - $5.75	$3.75 - $5.00	$3.25 - $3.80
Ceiling price range	$7.20 - $9.50	$5.16 - $9.65	$4.00 - $5.25
Percent of daily worldwide production	16%	33%	56%
Crude Oil Collars:			
NYMEX –			
Hedge Bopd	15,519	15,005	15,793
Floor price range	$29.00 - $32.00	$24.00 - $28.00	$23.00 - $27.00
Ceiling price range	$37.25 - $46.15	$30.00 - $38.65	$27.20 - $35.05
Percent of daily worldwide production	26%	33%	44%
Brent –			
Hedge Bopd	5,000	1,260	–
Floor price range	$32.50 - $37.50	$37.50 - $37.50	–
Ceiling price range	$49.50 - $56.50	$54.00 - $54.00	–
Percent of daily worldwide production	8%	3%	–

During 2005, the Company entered into various NYMEX and Brent fixed price swaps related to its crude oil and natural gas production. There were no fixed price swaps during 2004 and 2003. The tables below summarize the various transactions:

	2005
Natural Gas Swaps:	
NYMEX –	
Hedge MMBtupd	87,260
Average price per MMBtu	$6.76
Percent of daily worldwide production	17%
Crude Oil Swaps:	
Brent –	
Hedge Bopd	8,793
Average price per Bbl	$39.62
Percent of daily worldwide production	15%

As of December 31, 2005, the Company had open costless collar positions 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	Bopd	Floor	Ceiling
2006 (NYMEX)	3,699	$5.00	$8.00	1,865	$29.00	$34.93
2007 (Brent)	–	–	–	6,748	45.00	70.63
2008 (Brent)	–	–	–	4,077	45.00	66.52
2009 (Brent)	–	–	–	3,074	45.00	63.04

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 days 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, 2005, the Company had open fixed price swap positions related to its natural gas and crude oil production as follows:

	Natural Gas		Crude Oil	
Production Period	MMBtupd	Average Price per MMBtu	Bopd	Average price per Bbl
2006 (NYMEX) (1)	170,000	$6.49	16,600	$40.47
2007 (NYMEX)	170,000	6.04	17,100	39.19
2008 (NYMEX)	170,000	5.67	16,500	38.23

(1) Includes derivative instruments of 40,000 MMBtupd of natural gas and 6,000 Bopd of crude oil that did not qualify for hedge accounting treatment at December 31, 2005. These derivative instruments were re-designated as cash flow hedges in February 2006.

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 days 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, 2005 and 2004, the balance in AOCI included net deferred losses of $763.8 million and $6.9 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 $411.3 million and $3.7 million, respectively.

If commodity prices were to stay the same as they were at December 31, 2005, approximately $203.7 million of deferred losses, net of tax, related to the fair values of crude oil and natural gas derivative instruments included in AOCI at December 31, 2005 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 derivative instruments in connection with its purchases and sales of production in order to establish a fixed margin and mitigate the risk of price volatility. Most of the purchases 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 in connection with 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. The Company recorded a net loss of $1.5 million during 2005 related to derivative instruments. Net gains and losses for 2004 and 2003 were *de minimis*.

Receivables/Payables Related to Crude Oil and Natural Gas Derivative Instruments – At December 31, 2005, the Company's consolidated balance sheet included the following assets and liabilities related to derivative instruments:

	2005	2004
	(in thousands)	
Derivative instruments (current asset)	$ 29,258	$ 28,733
Derivative instruments (long-term asset)	17,259	20,427
Derivative instruments (current liability)	(445,939)	(50,304)
Derivative instruments (long-term liability)	(757,509)	(9,678)

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. At December 31, 2005, AOCI included a deferred loss of $4.1 million, net of tax, related to an interest rate swap. This amount is being reclassified into earnings as adjustments to interest expense over the term of the Company's 5¼% senior notes due 2014. At December 31, 2004, the amount of deferred loss included in AOCI was $4.6 million, net of tax. The amounts amortized to interest expense were $0.8 million and $0.5 million for the years ending December 31, 2005 and 2004, respectively.

Note 13 – Equity Method Investments

Noble Energy owns a 45% interest in Atlantic Methanol Production Company, LLC ("AMPCO"), which owns and operates a methanol production facility and related facilities in Equatorial Guinea and a 28% interest in Alba Plant, LLC ("Alba Plant"), which owns and operates a liquefied petroleum gas ("LPG") processing plant. Construction of the Alba Plant was funded primarily through advances by the Company and other owners in exchange for notes payable by the Alba Plant. The notes mature on December 31, 2011 and bear interest at the 90-day LIBOR rate plus 3%. Noble Energy owns 50% interests in AMPCO Marketing, LLC and AMPCO Services, LLC, which provide technical and consulting services. These investments, which are accounted for using the equity method, are included in equity method investments on the Company's balance sheets, and the Company's share of earnings is reported as income from equity method investments on the Company's statements of operations.

Summarized, 100% combined financial information for equity method investees was as follows:

Balance Sheet Information

	December 31, 2005	December 31, 2004
	(in thousands)	
Current assets	$274,484	$174,864
Noncurrent assets	877,402	826,499
Current liabilities	119,912	118,784
Noncurrent liabilities	450,156	381,509

Statements of Operations Information

	Year ended December 31, 2005	2004	2003
	(in thousands)		
Total revenues	$467,512	$310,558	$221,401
Gross margin	315,909	202,788	132,931
Net income	224,552	185,027	104,790

Noble Energy's share of income taxes incurred directly by the equity method investees is reported in income from equity method investments and is not included in the Company's income tax provision in the consolidated statements of operations.

Note 14 – Commitments and Contingencies

Legal Proceedings – The ruling by the Colorado Supreme Court in *Rogers v. Westerman Farm Co.* in July 2001 resulted in uncertainty regarding the deductibility of certain post-production costs from payments to be made to royalty interest owners. In January 2003, Patina was named as a defendant in a lawsuit, which plaintiff sought to certify as a class action, based upon the *Rogers* ruling alleging that Patina had improperly deducted certain costs in connection with its calculation of royalty payments relating to its Wattenberg field operations *(Jack Holman, et al v. Patina Oil & Gas Corporation; Case No. 03-CV-09; District Court, Weld County, Colorado)*. In May 2004, the plaintiff filed an amended complaint narrowing the class of potential plaintiffs, and thereafter filed a motion seeking to certify the narrowed class as described in the amended complaint. Patina filed an answer to the amended complaint. A motion seeking class certification was heard on September 22, 2005 and granted on October 13, 2005. The Colorado Supreme Court denied the Company's petition for review on November 23, 2005.

The Illinois Environmental Protection Agency (IEPA) issued a notice of violation to Equinox Oil Company on September 25, 2001 alleging violation of air emission and permitting regulations for a facility known as the Zif Gas Plant located near Clay City, Illinois. Elysium Energy, LLC, acquired Equinox, and Elysium subsequently was acquired by Patina. The facility is a small amine processing unit used to treat and remove hydrogen sulfide from natural gas prior to transportation. The notice of violation alleges violation of permit requirements under the Clean Air Act dating back to 1986 as well as excessive hydrogen sulfide emissions at the plant. The Company is cooperatively working with the IEPA staff to address this matter. It is within the discretion of the IEPA to assess a fine for violating emission and permit regulations but the Company has not been assessed a fine or other penalty at this time.

The Company and its subsidiaries are involved in various legal proceedings, including the foregoing matters, in the ordinary course of business. These proceedings are subject to the uncertainties inherent 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.

Non-Cancelable Leases and Other Commitments – At December 31, 2005, the Company and its consolidated subsidiaries held leases and other commitments for buildings, equipment, drilling rigs and other properties. Net rental expense from leases was approximately \$9.5 million, \$6.8 million and \$6.0 million for 2005, 2004 and 2003, respectively.

Net minimum commitments as of December 31, 2005 consist of the following:

	Net Minimum Commitments			
	Drilling Rig and Equipment Contracts	Building Leases	Equipment Leases	Total
	(in thousands)			
2006	$235,717	$ 4,986	$1,704	$242,407
2007	7,053	4,401	1,308	12,762
2008	–	4,308	1,128	5,436
2009	1,027	4,235	–	5,262
2010	63,308	4,132	–	67,440
2011 and thereafter	310,722	10,092	–	320,814
Total	$617,827	$32,154	$4,140	$654,121

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, Ecuador and Suriname.

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.

	Total	United States	Equatorial Guinea	North Sea	Israel	Other Int'l, Corporate & Marketing
			(in thousands)			
Year Ended December 31, 2005						
Revenues from third parties	$2,095,911	$ 913,564	$281,902	$123,584	$65,050	$ 711,811
Intersegment revenue	–	460,808	–	–	–	(460,808)
Income from equity method investments	90,812	–	90,812	–	–	–
Total Revenues	2,186,723	1,374,372	372,714	123,584	65,050	251,003
DD&A	390,544	311,153	27,121	9,888	11,188	31,194
Accretion of discount on asset retirement obligations	11,214	9,590	51	1,134	281	158
Impairment of operating assets	5,368	5,368	–	–	–	–
Income from continuing operations before tax	968,660	585,988	309,239	88,524	46,468	(61,559)
Investments in equity method investees	420,362	–	420,362	–	–	–
Additions to long-lived assets	4,382,005	4,345,604	2,738	15,287	5,928	12,448
Total assets at December 31, 2005[(1)]	8,878,033	6,577,853	877,409	146,311	266,312	1,010,148
Year Ended December 31, 2004						
Revenues from third parties	$1,272,852	$ 335,329	$132,590	$115,181	$48,855	$ 640,897
Intersegment revenue	–	455,068	–	–	–	(455,068)
Income from equity method investments	78,199	–	78,199	–	–	–
Total Revenues	1,351,051	790,397	210,789	115,181	48,855	185,829
DD&A	308,103	240,058	13,925	18,244	9,058	26,818
Accretion of discount on asset retirement obligations	9,352	8,021	6	1,140	163	22
Impairment of operating assets	9,885	9,885	–	–	–	–
Income from continuing operations before tax	513,008	294,412	162,576	70,305	32,088	(46,373)
Investments in equity method investees	377,384	–	377,384	–	–	–
Additions to long-lived assets	469,445	280,280	114,188	10,795	(8,313)	72,495
Total assets at December 31, 2004	3,435,784	1,299,547	809,675	218,881	273,347	834,334
Year Ended December 31, 2003						
Revenues from third parties	$ 963,040	$ 120,982	$ 60,151	$100,558	$ –	$ 681,349
Intersegment revenue	–	495,261	–	–	–	(495,261)
Income from equity method investments	45,186	–	45,186	–	–	–
Total Revenues	1,008,226	616,243	105,337	100,558	–	186,088
DD&A	308,586	254,041	5,358	28,219	40	20,928
Accretion of discount on asset retirement obligations	9,331	8,449	–	882	–	–
Impairment of operating assets	31,937	31,937	–	–	–	–
Income from continuing operations before tax	140,405	105,024	84,865	42,373	(7,743)	(84,114)
Investments in equity method investees	260,169	–	260,169	–	–	–
Additions to long-lived assets	371,363	110,320	180,371	6,622	66,751	7,299
Total assets at December 31, 2003	2,820,800	1,037,106	598,814	163,381	267,915	753,584

(1) The domestic reporting unit includes goodwill of $862.9 million related to the Patina Merger.

Note 16 – 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 $130 million. 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 previously 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:

	2004	2003
	(in thousands)	
Oil and gas sales and royalties	$12,575	$106,339
Write down to market value and realized gain (loss)	14,996	(59,171)
Income (loss) before income taxes	22,862	(9,325)

The Company's long-term debt is recorded at the consolidated level and is not allocated to components. Therefore, the Company allocated no interest expense to the discontinued operations.

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 and Denver offices perform all reserve estimates for the Company's different geographical regions. These reserve estimates are reviewed and approved by appropriate senior engineering staff and Division management with final approval by the Senior Vice President with responsibility for corporate reserves. During 2005, Noble Energy retained Netherland, Sewell & Associates, Inc. ("NSAI"), independent third-party reserve engineers, to perform a reserve audit of proved reserves. The reserve audit included a detailed review of eleven of the Company's major international, deepwater, and domestic properties, which covered approximately 72% of Noble Energy's total proved reserves. In 2004, Noble Energy also retained NSAI 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% of Noble Energy's total proved reserves. For 2003, Noble Energy retained NSAI 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.

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.

<u>Proved Undeveloped Reserves.</u> 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	Equatorial Guinea	Israel	Ecuador	North Sea	Argentina	Total
Proved reserves as of:							
January 1, 2005	519,735	917,409	417,293	119,341	11,714	1,369	1,986,861
Revisions of previous estimates	18,644	7,732	481	32,800	3,200	(1,301)	61,556
Extensions, discoveries and other additions	144,335	–	–	–	–	–	144,335
Production	(125,543)	(23,938)	(24,228)	(8,321)	(3,394)	(68)	(185,492)
Sale of minerals in place	–	–	–	–	–	–	–
Purchase of minerals in place	1,083,959	–	–	–	–	–	1,083,959
December 31, 2005	1,641,130	901,203	393,546	143,820	11,520	–	3,091,219
Proved reserves as of:							
January 1, 2004	558,058	537,998	450,307	79,298	13,811	2,448	1,641,920
Revisions of previous estimates	(7,452)	(4,130)	(15,441)	(27,398)	1,552	(937)	(53,806)
Extensions, discoveries and other additions	74,277	400,288	–	75,081	685	–	550,331
Production	(89,458)	(16,747)	(17,573)	(7,640)	(4,130)	(142)	(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	917,409	417,293	119,341	11,714	1,369	1,986,861
Proved reserves as of:							
January 1, 2003	621,716	425,420	450,307	84,993	14,478	3,887	1,600,801
Revisions of previous estimates	3,070	182	–	2,147	4,392	(1,147)	8,644
Extensions, discoveries and other additions	44,463	126,962	–	–	–	–	171,425
Production	(106,609)	(14,566)	–	(7,842)	(5,059)	(292)	(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	537,998	450,307	79,298	13,811	2,448	1,641,920
Proved developed gas reserves as of:							
January 1, 2006	1,278,788	431,142	336,681	143,820	11,520	–	2,201,951
January 1, 2005	430,513	447,347	360,428	119,341	11,714	1,118	1,370,461
January 1, 2004	506,457	462,474	378,001	25,130	13,811	2,197	1,388,070
January 1, 2003	576,378	425,420	–	34,436	14,478	3,664	1,054,376

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	Equatorial Guinea	North Sea	Argentina	China	Total
Proved reserves as of:						
January 1, 2005	55,066	108,730	9,336	9,831	10,501	193,464
Revisions of previous estimates	4,192	(1,303)	278	153	15	3,335
Extensions, discoveries and other additions	11,272	–	12,955	–	–	24,227
Production	(9,468)	(6,492)	(1,964)	(1,059)	(1,807)	(20,790)
Sale of minerals in place	–	–	–	–	–	–
Purchase of minerals in place	90,594	–	–	–	–	90,594
December 31, 2005	151,656	100,935	20,605	8,925	8,709	290,830
Proved reserves as of:						
January 1, 2004	42,304	113,198	8,460	8,921	10,336	183,219
Revisions of previous estimates	976	(1,104)	1,037	1,995	(1,438)	1,466
Extensions, discoveries and other additions	16,760	–	4,414	–	3,024	24,198
Production	(8,073)	(3,364)	(2,459)	(1,085)	(1,421)	(16,402)
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	108,730	9,336	9,831	10,501	193,464
Proved reserves as of:						
January 1, 2003	62,023	111,019	8,223	9,283	10,930	201,478
Revisions of previous estimates	1,216	(666)	3,654	(91)	609	4,722
Extensions, discoveries and other additions	1,949	4,840	–	768	–	7,557
Production	(7,402)	(1,995)	(2,705)	(1,039)	(1,203)	(14,344)
Sale of minerals in place	(15,482)	–	(712)	–	–	(16,194)
Purchase of minerals in place	–	–	–	–	–	–
December 31, 2003	42,304	113,198	8,460	8,921	10,336	183,219
Proved developed oil reserves as of:						
January 1, 2006	114,223	100,935	7,650	6,914	8,709	238,431
January 1, 2005	32,390	108,730	9,336	7,539	10,501	168,496
January 1, 2004	34,246	113,198	8,460	8,004	10,336	174,244
January 1, 2003	52,847	78,746	8,223	8,331	10,930	159,077

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:

	United States	Equatorial Guinea	Israel	North Sea	Other Int'l	Total
			(in thousands)			
December 31, 2005						
Revenues	$1,374,374	$281,901	$65,050	$123,583	$121,514	$1,966,422
Production costs (1)	216,478	30,659	8,504	12,503	28,796	296,940
Transportation	9,350	–	–	6,562	852	16,764
E&P corporate	34,162	435	188	2,591	947	38,323
Exploration expenses	130,018	5,463	223	5,985	13,021	154,710
DD&A and valuation provision	328,645	26,978	11,120	9,866	24,255	400,864
Impairment of operating assets	5,368	–	–	–	–	5,368
Accretion expense	9,590	51	281	1,134	158	11,214
Income before income taxes	640,763	218,315	44,734	84,942	53,485	1,042,239
Income tax expense	140,916	76,518	7,752	36,834	23,307	285,327
Results of continuing operations from producing activities (excluding corporate overhead and interest costs)	$ 499,847	$141,797	$36,982	$ 48,108	$ 30,178	$ 756,912
Company's share of equity method investee's results of operations from producing activities	$ –	$ 33,916	$ –	$ –	$ –	$ 33,916
December 31, 2004						
Revenues	$ 790,397	$132,590	$48,855	$115,181	$ 77,952	$1,164,975
Production costs (1)	125,018	20,811	7,203	8,803	21,526	183,361
Transportation	8,631	–	–	10,480	697	19,808
E&P corporate	15,599	596	163	2,302	(77)	18,583
Exploration expenses	73,971	7,214	598	11,115	2,810	95,708
DD&A and valuation provision	259,365	13,925	9,549	18,215	20,729	321,783
Impairment of operating assets	9,885	–	–	–	–	9,885
Accretion expense	8,021	6	163	1,140	22	9,352
Income before income taxes	289,907	90,038	31,179	63,126	32,245	506,495
Income tax expense	106,603	46,011	9,896	28,542	13,860	204,912
Results of continuing operations from producing activities (excluding corporate overhead and interest costs)	$ 183,304	$ 44,027	$21,283	$ 34,584	$ 18,385	$ 301,583
Company's share of equity method investee's results of operations from producing activities	$ –	$ 9,099	$ –	$ –	$ –	$ 9,099
December 31, 2003						
Revenues	$ 616,243	$ 60,152	$ –	$100,558	$ 59,907	$ 836,860
Production costs (1)	112,725	13,441	–	8,453	18,538	153,157
Transportation	10,877	–	–	9,024	987	20,888
E&P corporate	15,884	835	5	2,209	1,866	20,799
Exploration expenses	71,802	134	6,925	9,239	28,011	116,111
DD&A and valuation provision	278,426	5,344	910	29,405	23,795	337,880
Impairment of operating assets	31,937	–	–	–	–	31,937
Accretion expense	8,449	–	–	882	–	9,331
Income (loss) before income taxes	86,143	40,398	(7,840)	41,346	(13,290)	146,757
Income tax expense	17,795	20,537	(4,121)	19,586	9,479	63,276
Results of continuing operations from producing activities (excluding corporate overhead and interest costs)	$ 68,348	$ 19,861	$(3,719)	$ 21,760	$(22,769)	$ 83,481
Company's share of equity method investee's results of operations from producing activities	$ –	$ 4,560	$ –	$ –	$ –	$ 4,560

(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:

	United States	Equatorial Guinea	Israel	North Sea	Other Int'l	Total
			(in thousands)			
December 31, 2005						
Property acquisition costs						
Proved	$2,642,572	$ –	$ –	$ –	$ –	$2,642,572
Unproved	1,084,545	–	–	140	250	1,084,935
Total acquisition costs	3,727,117	–	–	140	250	3,727,507
Exploration costs	164,820	18,126	223	6,308	13,021	202,498
Development costs (1)(2)(3)	657,858	2,738	5,928	19,729	12,198	698,451
Total consolidated operations	4,549,795	20,864	6,151	26,177	25,469	4,628,456
Company's share of equity method investee's development costs	–	27,639	–	–	–	27,639
Worldwide total	$4,549,795	$ 48,503	$ 6,151	$26,177	$25,469	4,656,095
December 31, 2004						
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 (1)(2)(3)	174,179	100,155	(5,887)	9,509	74,039	351,995
Total consolidated operations	392,496	121,828	(5,289)	26,416	76,873	612,324
Company's share of equity method investee's development costs	–	61,498	–	–	–	61,498
Worldwide 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 (1)(2)(3)	100,844	180,371	66,751	7,176	7,249	362,391
Total consolidated operations	239,897	180,505	73,676	17,137	16,127	527,342
Company's share of equity method investee's development costs	–	41,944	–	–	–	41,944
Worldwide total	$ 239,897	$222,449	$73,676	$17,137	$16,127	$ 569,286

(1) United States development costs include $39.4 million, $5.2 million and $2.1 million related to asset retirement obligations in 2005, 2004 and 2003 respectively. United States asset retirement costs of $66.0 million and $130.0 million in 2005 and 2004, respectively, were incurred as a result of hurricane damage and are excluded from the costs incurred schedule above as the Company expects to recover the costs from insurance proceeds. See "Note 4 – Effect of Gulf Coast Hurricanes."

(2) North Sea development costs include $4.6 million, $3.4 million and $0.4 million related to asset retirement obligations in 2005, 2004 and 2003 respectively.

(3) Worldwide development costs include $471.2 million, $11.4 million and $274.6 million spent to develop proved undeveloped reserves in 2005, 2004, and 2003, respectively.

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:

	2005	2004
	(in thousands)	
Unproved oil and gas properties	$ 1,066,888	$ 150,484
Proved oil and gas properties [1]	7,335,188	3,982,730
Total oil and gas properties	8,402,076	4,133,214
Accumulated DD&A	(2,239,596)	(1,972,823)
Net capitalized costs	$ 6,162,480	$ 2,160,391
Company's share of equity method investee's net capitalized costs	$ 134,067	$ 121,776

(1) Included in proved oil and gas properties at December 31, 2005 and 2004 are asset retirement costs of $131.1 million and $90.6 million, 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, 2005, 2004 and 2003 in accordance with SFAS No. 69, "Disclosures About Oil and Gas Producing Activities." The standard requires the use of a 10% 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:

	United States	Equatorial Guinea	Israel	North Sea	Ecuador	Other Int'l	Total
			(in millions)				
December 31, 2005							
Future cash inflows [1]	$22,931	$5,436	$1,031	$1,267	$539	$868	$32,072
Future production costs [2]	5,099	556	154	352	47	290	6,498
Future development costs	1,887	92	88	184	12	37	2,300
Future income tax expenses	4,645	1,589	182	381	142	159	7,098
Future net cash flows	11,300	3,199	607	350	338	382	16,176
10% annual discount for estimated timing of cash flows	5,201	1,554	236	138	162	114	7,405
Standardized measure of discounted future net cash flows	$ 6,099	$1,645	$ 371	$ 212	$176	$268	$ 8,771
December 31, 2004							
Future cash inflows [1]	$ 5,429	$4,358	$1,089	$ 439	$377	$662	$12,354
Future production costs [2]	1,135	490	133	153	42	310	2,263
Future development costs	364	83	88	23	16	33	607
Future income tax expenses	1,219	1,704	264	109	129	93	3,518
Future net cash flows	2,711	2,081	604	154	190	226	5,966
10% annual discount for estimated timing of cash flows	1,104	1,079	249	33	82	77	2,624
Standardized measure of discounted future net cash flows	$ 1,607	$1,002	$ 355	$ 121	$108	$149	$ 3,342
December 31, 2003							
Future cash inflows [1]	$ 4,425	$3,391	$1,177	$ 316	$317	$582	$10,208
Future production costs [2]	986	635	139	113	46	248	2,167
Future development costs	339	199	84	25	49	19	715
Future income tax expenses	998	1,200	307	78	86	93	2,762
Future net cash flows	2,102	1,357	647	100	136	222	4,564
10% annual discount for estimated timing of cash flows	847	774	294	11	50	76	2,052
Standardized measure of discounted future net cash flows	$ 1,255	$ 583	$ 353	$ 89	$ 86	$146	$ 2,512

(1) The standardized measure of discounted future net cash flows for 2005, 2004 and 2003 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:

	United States	Equatorial Guinea	Israel	North Sea	Ecuador	Other Int'l	Total
December 31, 2005							
Average crude oil price per Bbl	$58.20	$51.62	$ –	$58.47	$ –	$49.23	$55.39
Average natural gas price per Mcf	8.59	0.25	2.62	5.39	3.75	–	5.16
December 31, 2004							
Average crude oil price per Bbl	$41.25	$37.97	$ –	$40.93	$ –	$32.52	$38.48
Average natural gas price per Mcf	6.07	0.25	2.61	4.84	3.16	0.84	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	0.25	2.61	4.15	4.00	0.38	2.95

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 $157.4 million or $148.3 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 $419.6 million, $266.9 million and $193.3 million that the Company expects to spend in 2006, 2007 and 2008, 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, 2005, the Company estimated imbalance receivables of $18.1 million and estimated imbalance liabilities of $34.6 million; at year-end 2004, $21.2 million in receivables and $16.1 million in liabilities; and at year-end 2003, $23.0 million in receivables and $18.8 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, 2005, 2004 and 2003.

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:

	Year ended December 31, 2005	2004	2003
	(in millions)		
Standardized measure of discounted future net cash flows at the beginning of the year	$ 3,342	$ 2,512	$2,732
Extensions, discoveries and improved recovery, less related costs	1,173	839	247
Revisions of previous quantity estimates	273	(70)	115
Changes in estimated future development costs	(912)	99	(148)
Purchases (sales) of minerals in place	4,720	12	(115)
Net changes in prices and production costs	2,160	861	(312)
Accretion of discount	519	406	405
Sales of oil and gas produced, net of production costs	(1,563)	(1,014)	(793)
Development costs incurred during the period	751	92	243
Net change in income taxes	(2,099)	(380)	(216)
Change in timing of estimated future production, and other	407	(15)	354
Standardized measure of discounted future net cash flows at the end of the year	$ 8,771	$ 3,342	$2,512

Supplemental Quarterly Financial Information (Unaudited)

Supplemental quarterly financial information for the years ended December 31, 2005 and 2004 is as follows:

	Quarter Ended Mar. 31,	June 30,	Sept. 30,	Dec. 31,
	(in thousands except per share amounts)			
2005 [(1)]				
Revenues	$368,212	$485,443	$632,088	$700,980
Income from continuing operations before taxes	174,482	224,405	241,136	328,637
Income from continuing operations	109,968	136,877	176,956	221,919
Net income	109,968	136,877	176,956	221,919
Basic earnings per share:				
Income from continuing operations	0.93	0.94	1.01	1.27
Net income	0.93	0.94	1.01	1.27
Diluted earnings per share:				
Income from continuing operations	0.92	0.91	0.99	1.18
Net income	0.92	0.91	0.99	1.18
2004 [(2)]				
Revenues	$318,124	$336,052	$319,667	$377,208
Income from continuing operations before taxes	128,090	115,225	127,833	141,861
Income from continuing operations	75,312	70,628	80,971	86,938
Discontinued operations, net of tax	10,234	1,399	2,721	507
Net income	85,546	72,027	83,692	87,445
Basic earnings per share:				
Income from continuing operations	0.65	0.61	0.69	0.74
Discontinued operations, net of tax	0.09	0.01	0.03	–
Net income	0.74	0.62	0.72	0.74
Diluted earnings per share:				
Income from continuing operations	0.65	0.60	0.68	0.73
Discontinued operations, net of tax	0.08	0.01	0.03	–
Net income	0.73	0.61	0.71	0.73

(1) Revenues as previously reported totaled $365,234 for first quarter, $488,368 for second quarter, and $645,169 for third quarter 2005. These amounts have been reclassified to conform to fourth quarter 2005 presentation. Third quarter 2005 includes a non-cash charge of $5.2 million ($3.4 million, net of tax) related to the impairment of operating assets. Third quarter 2005 also includes a charge of $14.5 million related to the involuntary conversion of assets caused by Hurricane Katrina and a related credit for insurance recoveries of $13.5 million, resulting in a net loss of $1.0 million. Fourth quarter 2005 includes discontinuation of hedge accounting treatment on certain derivatives resulting in a mark-to-market gain of $20.0 million ($13.0 million, net of tax) recognized in the Company's results of operations. In addition, a loss of $51.8 million ($33.7 million, net of tax) associated with the discontinued hedge accounting treatment, which had been previously deferred in AOCI, was reclassified to earnings in fourth quarter 2005 as an increase in other expense (income), net in the consolidated statement of operations. See "Note 12 – Derivative Instruments and Hedging Activities."

(2) 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 assets caused by Hurricane Ivan and a related credit for insurance recoveries of $153.0 million, resulting in a net loss of $1.0 million.

Atlantic Methanol Production Company, LLC
Financial Statements
For the Years Ended December 31, 2005, 2004 and 2003

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying balance sheets of Atlantic Methanol Production Company, LLC (the "Company") as of December 31, 2005 and 2004, and the related statements of income, 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 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 financial statements referred to above present fairly, in all material respects, the financial position of Atlantic Methanol Production Company, LLC as of December 31, 2005 and 2004, 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 of America.

/s/ UHY Mann Frankfort Stein & Lipp, CPAs, LLP

Houston, Texas
January 25, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Members
Atlantic Methanol Production Company, LLC

We have audited the accompanying statement of income, members' equity and cash flows of Atlantic Methanol Production Company, LLC for the year ended December 31, 2003. 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 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the results of operations and cash flows of Atlantic Methanol Production Company, LLC for the year ended December 31, 2003 in conformity with U.S. generally accepted accounting principles.

Ernst & Young LLP

January 28, 2004
Fort Worth, Texas

ATLANTIC METHANOL PRODUCTION COMPANY, LLC
BALANCE SHEETS
(Dollars in thousands)

	December 31, 2005	December 31, 2004
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 15,933	$ 16,161
Accounts receivable – trade	2,524	12,669
Accounts receivable – affiliates	21,623	21,286
Other receivables	211	690
Inventories	15,016	11,740
Prepaid expenses and deposits	2,937	5,785
Deferred methanol cost	2,385	4,527
Deferred expenses	908	2,611
Deferred tax asset	3,267	16,495
TOTAL CURRENT ASSETS	64,804	91,964
PROPERTY PLANT AND EQUIPMENT, NET	380,889	370,495
TOTAL ASSETS	$445,693	$462,459
LIABILITIES AND MEMBERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable – trade	$ 899	$ 1,274
Accounts payable – affiliates	1,297	3,588
Accrued liabilities	16,923	17,490
Foreign income taxes payable	7,097	–
Other taxes payable	571	434
Deferred revenue	15,877	31,014
Deferred rent expense	266	–
Distributions payable	4,635	1,375
TOTAL CURRENT LIABILITIES	47,565	55,175
LONG TERM LIABILITIES		
Deferred rent expense, net of current portion	2,391	–
Deferred tax liability	173	–
TOTAL LONG TERM LIABILITIES	2,564	–
MEMBERS' EQUITY	395,564	407,284
TOTAL LIABILITIES AND MEMBERS' EQUITY	$445,693	$462,459

ATLANTIC METHANOL PRODUCTION COMPANY, LLC
STATEMENTS OF INCOME
(Dollars in thousands)

	Year Ended December 31,		
	2005	**2004**	**2003**
INCOME			
Methanol sales	$271,747	$217,702	$171,127
Shipping revenues	657	1,356	2,306
Legal settlements	–	10,895	–
Sales of purchased third-party methanol	–	–	341
Foreign exchange gains	–	316	–
Other revenues	7,435	13,733	11,829
TOTAL INCOME	279,839	244,002	185,603
COSTS AND EXPENSES			
Cost of methanol	24,987	21,815	27,550
Shipping	33,511	26,563	19,011
Marketing	7,533	6,210	5,189
Cost of third-party purchased methanol sold	–	–	428
Net bridge cost recovery loss	–	253	318
Foreign exchange losses	1,654	–	–
Depreciation	19,073	18,651	19,197
General and administrative	22,088	26,727	22,664
Net profit interest	13,070	11,485	5,201
Ship charter expense	511	333	1,079
TOTAL COSTS AND EXPENSES	122,427	112,037	100,637
INCOME BEFORE TAX	157,412	131,965	84,966
INCOME TAX PROVISION (BENEFIT)			
Current	23,231	–	–
Deferred	13,401	(16,495)	–
TOTAL INCOME TAX PROVISION (BENEFIT)	36,632	(16,495)	–
NET INCOME	$120,780	$148,460	$ 84,966

ATLANTIC METHANOL PRODUCTION COMPANY, LLC
STATEMENTS OF MEMBERS' EQUITY
(Dollars in thousands)

	Year Ended December 31,		
	2005	2004	2003
Balance at beginning of year	$407,284	$394,761	$412,295
Net income	120,780	148,460	84,966
Distributions declared to members	(132,500)	(128,500)	(102,500)
Return of capital	–	(7,437)	–
Balance at end of year	$395,564	$407,284	$394,761

ATLANTIC METHANOL PRODUCTION COMPANY, LLC
STATEMENTS OF CASH FLOWS
(Dollars in thousands)

	Year Ended December 31,		
	2005	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$120,780	$148,460	$ 84,966
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation expense	19,073	18,651	19,197
Deferred income tax	13,401	(16,495)	–
Changes in operating assets and liabilities:			
Accounts receivable – trade	10,145	(6,492)	7,374
Accounts receivable – affiliates	(337)	(11,257)	(2,569)
Other receivables	479	(462)	(228)
Inventories	(3,276)	314	(996)
Prepaid expenses and deposits	2,848	(760)	(2,148)
Deferred methanol cost	2,142	(1,231)	2,263
Deferred expenses	1,703	(1,037)	(1,574)
Accounts payable – trade	(375)	747	(3,786)
Accounts payable – affiliates	(2,291)	3,357	(214)
Accrued liabilities	(567)	6,071	7,131
Other taxes payable	7,234	(199)	–
Deferred revenue	(15,137)	15,668	(749)
Deferred rent expense	2,657	–	–
NET CASH PROVIDED BY OPERATING ACTIVITIES	158,479	155,335	108,667
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(29,467)	(15,582)	(4,758)
NET CASH USED IN INVESTING ACTIVITIES	(29,467)	(15,582)	(4,758)
CASH FLOWS FROM FINANCING ACTIVITIES			
Distributions to members	(129,240)	(127,125)	(105,030)
Return of capital	–	(7,437)	–
NET CASH USED IN FINANCING ACTIVITIES	(129,240)	(134,562)	(105,030)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(228)	5,191	(1,121)
CASH AND CASH EQUIVALENTS, beginning of year	16,161	10,970	12,091
CASH AND CASH EQUIVALENTS, end of year	$ 15,933	$ 16,161	$ 10,970
NON CASH INVESTING AND FINANCING ACTIVITIES			
Distributions payable	$ 3,260	$ 1,375	$ –

ATLANTIC METHANOL PRODUCTION COMPANY, LLC
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2005, 2004 AND 2003

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 Sociedad Nacional de Gas de Guinea Ecuatorial (SONAGAS). This 10% share was transferred in 2005 from Guinea Equatorial Oil and Gas Marketing Ltd. (GEOGM) to SONAGAS. 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.

Accounts Receivable: Accounts receivable primarily represent accrued revenues related to methanol sales and are not collateralized.

Inventories: Inventories consist of methanol held in tanks of approximately $3,809,000 and $2,247,000 as of December 31, 2005 and 2004, 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 $11,207,000 and $9,493,000 of costs as of December 31, 2005 and 2004, 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 2005 and 2004.

The estimated costs of major maintenance, including turnarounds at the production facility, are capitalized and amortized over the period until the next planned turnaround. The Company anticipates a turnaround in 2006.

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 64,428 and zero metric tons of methanol held by Marketing and MG, respectively, at December 31, 2005, and approximately 92,623 and 39,978 metric tons of methanol held by Marketing and

NOTE B – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

MG, respectively, at December 31, 2004 that had not been sold to third parties. At December 31, 2005 and 2004, revenue from provisional billings of approximately $16 million and $31 million, respectively, associated with these volumes were recorded as deferred revenue on the accompanying balance sheets. Cost of methanol related to these volumes of approximately $2.4 million and $4.5 million, at December 31, 2005 and 2004, 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 U.S. 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 of America 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.

Concentrations of Credit Risk: The Company maintains cash balances at financial institutions in the United States of America, which exceed federally insured amounts. The Company has not experienced any losses in such accounts.

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 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 basis 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 as of December 31, 2005 and 2004, as management believes 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, 2005 and 2004, the Company had approximately $0.1 million and $0.3 million in payables, respectively, for consulting services provided by Services, which is included in accounts payable – affiliates on the accompanying balance sheets. During 2005 and 2004, the Company incurred costs of approximately $3.3 million and $2.4 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 275,000 to 600,000 metric tons of methanol on an annual basis through 2006. The agreement automatically renews for successive additional periods of one year unless six months written notice is given by either party. No such notice has been given by either party as of December 31, 2005. In addition, Marketing also has the option to purchase additional quantities from the Company in excess of this commitment. 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,	
	2005	2004
	(in thousands)	
Plant	$421,393	$411,706
Machinery and equipment	4,557	4,255
Furniture and fixtures	2,665	2,471
Software costs	3,758	2,788
Vehicles	1,866	1,786
Other	2,014	2,014
	436,253	425,020
Less: accumulated depreciation	85,052	65,979
	351,201	359,041
Construction in progress	29,688	11,454
Property, plant and equipment, net	$380,889	$370,495

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 is liable for income taxes beginning in 2005. During the income tax holiday the Company recorded depreciation for book purposes but was not required to take any reductions to the related assets carrying value for tax purposes. Accordingly, during the tax holiday, the Company recorded a deferred tax asset equal to the amount of depreciation taken for book purposes multiplied by the statutory tax rate of 25%.

Temporary differences which give rise to deferred tax assets and liabilities are as follows:

	December 31,	
	2005	2004
Deferred tax assets – Current		
Property, plant, & equipment	$ –	$16,495,000
Net profit interest	3,267,000	–
	3,267,000	16,495,000
Deferred tax liability – Non Current		
Property, plant & equipment	173,000	–
Net deferred tax asset before valuation allowance	3,094,000	16,495,000
Valuation allowance	–	–
Net deferred tax asset	$3,094,000	$16,495,000

The change in the deferred tax asset valuation allowance was $0 and $(11,832,000) for the years ended December 31, 2005 and 2004, respectively. Management believes that 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. The

NOTE F – COMMITMENTS AND CONTINGENCIES (Continued)

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,	
2006	$ 7,000,000
2007	7,000,000
2008	7,000,000
2009	7,000,000
2010	7,000,000
Thereafter	107,333,000
	$142,333,000

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 three Global customers, unrelated third parties, to sell 315,000 and 368,000 metric tons, respectively, of methanol on an annual basis through 2006. 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.

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 currently, for each vessel, $17,300 per day accelerating to $17,500 per day in year 11 of the leases. At any time during the term of the leases, 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. During 2005, the Company exercised their 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 rental and

NOTE G – LEASES (Continued)

related operating costs of the vessels are reflected as shipping expense on the accompanying statements of income rental.

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,	
2006	$ 17,803,000
2007	17,739,000
2008	13,171,000
2009	12,564,000
2010	12,600,000
Thereafter	40,950,000
	$114,827,000

NOTE H – BRIDGE COST RECOVERY LOSS

The Company uses Marketing to sell the Company's methanol in the United States of America. 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 statement of income for the years ended 2004 and 2003.

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, and is paid by the Company in the following year. The Net Profits Interest went into effect in 2003.

NOTE J – SHIPPING REVENUE AND SHIP CHARTER EXPENSE

During 2005 and 2004, 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 2004, the Company identified an error in contributions that occurred in 2002. 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 $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.

None.

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.

Noble Energy's principal executive officer and principal financial officer have 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.

Management's Annual Report on Internal Control Over Financial Reporting

See "Item 8. Management's Report on Internal Control Over Financial Reporting."

Changes in Internal Control over Financial Reporting

Management of the Company is also responsible for establishing and maintaining adequate internal controls over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal controls were designed to provide reasonable assurance as to the reliability of our financial reporting and the preparation and presentation of the consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States.

Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Projections of any evaluation of the 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.

Our management has assessed the effectiveness of our internal controls over financial reporting as of December 31, 2005. Based on our assessment, our internal controls over financial reporting were effective based on the following qualification. Management included all consolidated entities of the Company except for those related to the Patina Merger, which occurred on May 16, 2005. We excluded this entity from our assessment as the merger was completed in second quarter 2005, and it was not possible to conduct our assessment between the date of the merger and December 31, 2005.

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 2006 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 2006 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 2006 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 2006 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 and Related Stockholder Matters.

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 2006 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 2006 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 2006 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, Financial Statements Schedules

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

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

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).
2.2	–	Amendment Agreement dated as of May 3, 2005 to the Agreement and Plan of Merger by and among Noble Energy, Inc., Noble Energy Production, Inc. and Patina Oil & Gas Corporation dated as of December 15, 2004 (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K (Date of Event: May 3, 2005) filed May 4, 2005, 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 7¼% Notes Due 2023, including form of the Registrant's 7¼% 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 7¼% 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).

Exhibit Number		Exhibit**
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).
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 April 25, 2005, and approved by the stockholders of the Company on April 29, 2003 (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 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, 2005) filed February 7, 2005 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, 2005) filed February 7, 2005 and incorporated herein by reference).
10.8*	–	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).
10.9*	–	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).
10.10*	–	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).

Exhibit Number		Exhibit**
10.11	–	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).
10.12	–	Stock Purchase Agreement dated as of July 1, 1996, between Samedan Oil Corporation and Enterprise Diversified Holdings Incorporated (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K (Date of Event: July 31, 1996) dated August 13, 1996 and incorporated herein by reference).
10.13	–	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).
10.14*	–	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).
10.15*	–	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).
10.16	–	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).
10.17	–	364-day Credit Agreement dated as of November 27, 2002 among the Registrant, as borrower, JPMorgan Chase Bank, as the administrative agent for the lenders, Wachovia Bank, National Association, as the syndication agent for the lenders, Societe Generale, Citibank, N.A., Deutsche Bank Ag New York Branch, and The Royal Bank of Scotland PLC, as co-documentation agents, and certain commercial lending institutions, as lenders, (filed as Exhibit 10.19 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).
10.18	–	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).
10.19	–	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).

Exhibit Number		Exhibit**
10.20	–	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).
10.21	–	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).
10.22	–	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).
10.23	–	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).
10.24	–	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).
10.25	–	$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).
10.26*	–	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).
10.27*	–	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, 2005) filed February 7, 2005 and incorporated herein by reference).
10.28	–	Purchase and Sale Agreement, dated February 7, 2006, among Noble Energy Production, Inc., U.S. Exploration Holdings, LLC, U.S. Exploration Holdings, Inc. and United States Exploration, Inc., filed herewith.
10.29	–	$2.1 billion Five-Year Credit Agreement, dated December 9, 2005, among Noble Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, Wachovia Bank, National Association and The Royal Bank of Scotland PLC, as co-syndication agents, Deutsche Bank Securities Inc. and Citibank, N.A., 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: December 9, 2005), filed December 14, 2005 and incorporated herein by reference).
10.30*	–	Noble Energy, Inc. 2005 Non-Employee Director Fee Deferral Plan, dated December 5, 2005 and effective as of January 1, 2005 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: December 5, 2005), filed December 8, 2005 and incorporated herein by reference).

Exhibit Number		Exhibit**
10.31*	–	Amendment No. 1 to the Noble Energy, Inc. Non-Employee Director Fee Deferral Plan, dated December 5, 2005 and effective as of January 1, 2005 (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Event: December 5, 2005), filed December 8, 2005 and incorporated herein by reference).
10.32*	–	Consulting Agreement, dated May 9, 2005 but commencing May 16, 2005, by and between Noble Energy, Inc. and Thomas J. Edelman (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: May 16, 2005), filed May 20, 2005 and incorporated herein by reference).
10.33*	–	2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: April 26, 2005) filed April 29, 2005 and incorporated herein by reference).
10.34*	–	Form of Stock Option Agreement under the Noble Energy, Inc. 2005 Non-Employee Director Stock Plan (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and incorporated herein by reference).
10.35*	–	Form of Restricted Stock Agreement under the Noble Energy, Inc. 2005 Non-Employee Director Stock Plan (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and incorporated herein by reference).
10.36*	–	Form of Restricted Stock Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan entered into by certain executive officers and key employees of the Company on May 16, 2005 and August 1, 2005, respectively (filed as Exhibit 10.4 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 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, filed herewith.
23.4	–	Consent of Netherland, Sewell & Associates, Inc., 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 and Chief Financial Officer, Noble Energy, Inc., 100 Glenborough Drive, Suite 100, Houston, Texas 77067.

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 1, 2006	By: /s/ CHARLES D. DAVIDSON Charles D. Davidson, Chairman of the Board, President, Chief Executive Officer and Director
Date: March 1, 2006	By: /s/ CHRIS TONG Chris Tong, Senior Vice President, Chief Financial Officer
Date: March 1, 2006	By: /s/ FREDERICK B. BRUNING Frederick B. Bruning, Chief Accounting Officer

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 1, 2006
/s/ CHRIS TONG Chris Tong	Senior Vice President, Chief Financial Officer (Principal Financial Officer)	March 1, 2006
/s/ FREDERICK B. BRUNING Frederick B. Bruning	Chief Accounting Officer (Principal Accounting Officer)	March 1, 2006
/s/ JEFFREY L. BERENSON Jeffrey L. Berenson	Director	March 1, 2006
/s/ MICHAEL A. CAWLEY Michael A. Cawley	Director	March 1, 2006
/s/ EDWARD F. COX Edward F. Cox	Director	March 1, 2006
/s/ THOMAS J. EDELMAN Thomas J. Edelman	Director	March 1, 2006
/s/ KIRBY L. HEDRICK Kirby L. Hedrick	Director	March 1, 2006
/s/ BRUCE A. SMITH Bruce A. Smith	Director	March 1, 2006
/s/ WILLIAM T. VAN KLEEF William T. Van Kleef	Director	March 1, 2006

GLOSSARY

In this report, the following abbreviations are used:

Bbl(s)	Barrel(s)
MBbls	Thousand barrels
MMBbls	Million barrels
Bpd	Barrels per day
MBpd	Thousand barrels per day
MMBpd	Million barrels per day
Bopd	Barrels oil per day
MBopd	Thousand barrels oil per day
MMBopd	Million barrels oil per day
Boe	Barrels oil equivalent
MBoe	Thousand barrels oil equivalent
MMBoe	Million barrels oil equivalent
Boepd	Barrels oil equivalent per day
MBoepd	Thousand barrels oil equivalent per day
MMBoepd	Million barrels oil equivalent per day
MGal	Thousand gallons
KW	Kilowatt
KWh	Kilowatt hours
MW	Megawatt
MWh	Megawatt hours
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Bcf	Billion cubic feet
Mcfpd	Thousand cubic feet per day
MMcfpd	Million cubic feet per day
Bcfpd	Billion cubic feet per day
Mcfe	Thousand cubic feet equivalent
MMcfe	Million cubic feet equivalent
Bcfe	Billion cubic feet equivalent
Mcfepd	Thousand cubic feet equivalent per day
MMcfepd	Million cubic feet equivalent per day
Bcfepd	Billion cubic feet equivalent per day
BTU	British thermal unit
MMBtu	Million British thermal units
MMBtupd	Million British thermal units per day
Btupcf	British thermal unit per cubic foot
Mt	Metric tons
Mtpd	Metric tons per day
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
NGL	Natural Gas Liquid
PSC	Production Sharing Contract

NOTES