NEWFIELD EXPLORATION CO /DE/
Form 10-K
March 01, 2007

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

Form 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2006

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number: 1-12534
Newfield Exploration Company
(Exact name of registrant as specified in its charter)

Delaware *(State of incorporation)*	**72-1133047** *(I.R.S. Employer Identification No.)*
363 North Sam Houston Parkway East, Suite 2020, Houston, Texas *(Address of principal executive offices)*	**77060** *(Zip Code)*

Registrant s telephone number, including area code:
281-847-6000

Securities registered Pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange on Which Registered**
Common Stock, par value $0.01 per share	New York Stock Exchange
Rights to Purchase Series A Junior Participating Preferred Stock, par value $0.01 per share	New York Stock Exchange

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 þ No o

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

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 þ No o

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. o

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 þ Accelerated filer o Non-accelerated filer o

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was approximately $6 billion as of June 30, 2006 (based on the last sale price of such stock as quoted on the New York Stock Exchange).

As of February 26, 2007, there were 129,995,347 shares of the registrant s common stock, par value $0.01 per share, outstanding.

Documents incorporated by reference: Proxy Statement of Newfield Exploration Company for the Annual Meeting of Stockholders to be held May 3, 2007, which is incorporated by reference into Part III of this Form 10-K.

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If you are not familiar with any of the oil and gas terms used in this report, we have provided explanations of many of them under the caption Commonly Used Oil and Gas Terms at the end of Item 7 of this report. Unless the context otherwise requires, all references in this report to Newfield, we, us or our are to Newfield Exploration Company ar its subsidiaries. Unless otherwise noted, all information in this report relating to oil and gas reserves and the estimated future net cash flows attributable to those reserves are based on estimates we prepared and are net to our interest.

PART I

Item 1. *Business*

We are an independent oil and gas company engaged in the exploration, development and acquisition of crude oil and natural gas properties. Our company was founded in 1989 and for the first ten years of our existence we focused on the shallow waters of the Gulf of Mexico. Today, we have a diversified asset base. Our domestic areas of operation include the Anadarko and Arkoma Basins of the Mid-Continent, the onshore Gulf Coast, the Uinta Basin of the Rocky Mountains and the Gulf of Mexico. Internationally, we are active offshore Malaysia and China and in the U.K. North Sea.

General information about us can be found at *www.newfield.com.* Our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after we file or furnish them. Information contained at our website is not incorporated by reference into this report and you should not consider information contained at our website as part of this report.

At year-end 2006, we had proved reserves of 2.3 Tcfe. Of those reserves:

- 70% were natural gas;
- 65% were proved developed;
- 35% were located in the Mid-Continent;
- 20% were located onshore in the Gulf Coast;
- 20% were located in the Rocky Mountains;
- 15% were located in the Gulf of Mexico; and
- 10% were located internationally.

Strategy

The elements of our growth strategy have remained substantially unchanged since our founding and consist of:

- growing reserves through the drilling of a balanced risk/reward portfolio and select acquisitions;
- focusing on select geographic areas;
- controlling operations and costs;

using advanced technologies; and

attracting and retaining a quality workforce through equity ownership and other performance-based incentives.

Drilling Program. In an effort to manage the risks associated with our strategy to grow reserves through the drill bit, each year we drill a greater number of lower risk, low to moderate potential wells and a lesser number of higher risk, higher potential prospects. Our low-risk drilling opportunities in the Mid-Continent, the Rocky Mountains and the shallow waters of Malaysia and the Gulf of Mexico are complemented with higher potential plays in areas like the Gulf of Mexico s deepwater and in international waters. We actively look for new drilling ideas on our existing property base and on properties that may be acquired. In 2006, substantially all of our reserve additions came through the drillbit.

Acquisitions. We actively pursue the acquisition of proved oil and gas properties in select geographic areas. The potential to add reserves through the drill bit is a critical consideration in our acquisition screening process. From 2000 through 2004, we made several large acquisitions that helped establish new focus areas. Since 2004, our production and reserve growth has come primarily through the success of our drilling programs. Recently, higher commodity prices and stiff competition for acquisitions have significantly increased the cost of available properties. As a result, we have looked to alternative ways to gain access to oil and gas properties such as joint venture alliances and leasing efforts. We did not complete any significant acquisitions during 2006.

Geographic Focus. We believe that our long-term success requires extensive knowledge of the geologic and operating conditions in the areas where we operate. Because of this belief, we focus our efforts on a limited number of geographic areas where we can use our core competencies and have a significant influence on operations. We also believe that geographic focus allows us to make the most efficient use of our capital and personnel.

Control of Operations and Costs. In general, we prefer to operate our properties. By controlling operations, we can better manage production performance, control operating expenses and capital expenditures, consider the application of technologies and influence timing. At year-end 2006, we operated about 70% of our net total production.

Technology. By investing in technology, we give our people the tools they need to succeed. We rely on 3-D seismic surveys in all of our major areas of operation and use the full range of technologies to identify opportunities.

Equity Ownership and Incentive Compensation. We want our employees to act like owners. To achieve this, we reward and encourage them through equity ownership and performance-based compensation. A significant portion of our employees compensation is contingent on our profitability. As of February 26, 2007, our employees owned or had options to acquire 7.3% of our outstanding common stock on a fully diluted basis.

Focus Areas

Mid-Continent. Through an acquisition in January 2001, we added the Mid-Continent as a focus area. Since that time, we have tripled our proved reserves and tripled our production from this area. The Mid-Continent now represents 35% of our total proved reserves. The Mid-Continent is a gas-rich province characterized by multiple productive zones. Our two most active plays, the Woodford Shale and the Mountain Front Wash, are characterized by multiple producing horizons and large acreage positions. We drilled 354 wells in the Mid-Continent in 2006 and have a multi-year inventory of lower risk drilling opportunities. Our Mid-Continent division is managed by our Tulsa, Oklahoma office.

Onshore Gulf Coast. We established onshore Gulf Coast operations in 1995 and made major acquisitions in 2000 and 2002 to establish a significant presence in the onshore Gulf Coast. Today, this region is a major focus area for us, representing about 20% of our total proved reserves. Our operations are concentrated in South Texas, the Val Verde Basin of West Texas and East Texas.

Rocky Mountains. Through an acquisition in August 2004, we entered the Uinta Basin of the Rocky Mountains. The Monument Butte Field, located in northeastern Utah, now accounts for approximately 20% of our total proved reserves. The field offers a multi-year drilling inventory of lower risk wells. We drilled 199 wells in the field in 2006. The multiple basins of the Rocky Mountains, which have significant remaining reserves, offer us opportunities for growth and we are actively pursuing acquisition opportunities in those basins. Our Rocky Mountain division is managed by our Denver, Colorado office.

Gulf of Mexico. We are active in all of the major plays in the Gulf of Mexico: the traditional shelf, the deep and ultra-deep shelf and deepwater. Although traditional shelf plays are mature, we remain active and are finding creative ways to leverage our geologic expertise and infrastructure. We operate about 180 production platforms in shallow water. This infrastructure facilitates cost effective operations and timely development of our discoveries. We have added significant new projects in deepwater over the last two years. At year-end 2006, we were producing from four deepwater fields, and our first operated development the Wrigley Field is being prepared for production.

Although we believe that significant opportunities remain in the deep shelf play, the economics of these prospects have been negatively impacted by significantly higher rates for offshore rigs. As a result, we have elected to defer most of these opportunities.

In 2005 and 2006, we drilled our first ultra-deep well on our Blackbeard prospect. This well was part of an exploration initiative we refer to as Treasure Project. The well was drilled to a total depth of 30,067 feet and encountered a thin gas-bearing sand below 30,000 feet. The well failed to reach its primary targets because of higher than expected pressure. The well has been temporarily abandoned. We are working with the MMS to extend the leases containing the prospect, all of which are beyond their primary terms. The ultra-deep targets are high risk but the potential reserve impact could be significant. We have more than 90 lease blocks associated with this concept. There is no production from these depths on the Gulf of Mexico shelf today.

International. Our international operations have grown significantly over the last several years. We now have production from offshore China and Malaysia and are preparing to bring the Grove Field, our first operated field in the U.K. North Sea, on-line. We continue to seek ways to grow our presence in these areas and have a team dedicated to finding new international regions where we can employ our expertise. We have international offices in Beijing, Kuala Lumpur and London.

We have interests in two offshore Malaysia blocks that together include current production, undeveloped discoveries and lower risk drilling prospects in shallow water and a large deepwater exploration concession. We have four fields under development and we drilled our first deepwater prospect in late 2006. The well, located on Block 2C, found non-commercial quantities of natural gas. The geologic information gathered from this well is being incorporated into our interpretation for other prospects on Block 2C. We have a commitment to drill one additional exploratory well on this block.

During the third quarter of 2006, we commenced production from two oil fields in China s Bohai Bay. During 2005, we added two license areas offshore Hong Kong in the Pearl River Mouth Basin and we acquired seismic data for these areas in 2006. We are seeking additional opportunities both onshore and offshore China.

For revenues from our domestic and international operations, see Note 16, Segment Information, to our consolidated financial statements appearing later in this report.

Plans for 2007

Our capital budget for 2007 is approximately $1.8 billion, including about $50 million for continuing hurricane repairs in the Gulf of Mexico and excluding approximately $100 million of capitalized interest and overhead. About $290 million has been earmarked for exploration (exclusive of exploitation) activities. We do not budget for potential acquisitions. We plan to drill approximately 450 wells in 2007, about 80% of which are lower risk wells in the Mid-Continent or the Uinta Basin.

Mid-Continent. Our largest focus area investment in 2007 will be the Mid-Continent. We expect to drill about 200 wells and invest approximately $700 million. The majority of the planned drilling is associated with the development of our Woodford Shale play. We expect to drill about 150 horizontal wells in the play in 2007.

Onshore Gulf Coast. In 2007, we will balance development drilling of lower risk opportunities with some higher risk, higher impact exploration tests. South Texas will be a significant part of this focus area in 2007. We plan to drill 10-12 wells in South Texas under a joint venture agreement with Exxon-Mobil. Overall, we plan to drill about 70 wells and invest approximately $350 million in the onshore Gulf Coast during 2007.

Rocky Mountains. Our primary capital program in the Monument Butte Field consists of drilling shallow, lower risk wells and water injection wells, waterflood optimization activities and investment in field infrastructure. We plan to drill about 150 wells in the field during 2007. A successful 20-acre infill drilling pilot program, conducted in 2006, indicates that field development will support an additional 1,000 wells.

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Production from Monument Butte has been negatively impacted by refining capacity in the Salt Lake City area. We expect our 2007 oil sales to benefit from recent agreements with refiners which allow for firm capacity of approximately 11,000 BOPD (gross) through 2008 and 7,400 BOPD (gross) through 2009. We are working with other area refiners to secure additional capacity. Please see the discussion under the caption *We may not achieve future production growth from our Monument Butte Field* in Item 1A of this report. Our 2007 capital budget includes $135 million for our activities in the Rocky Mountains.

Gulf of Mexico. We expect to drill about 20-25 wells in 2007, including 15-20 in the traditional shelf and 4-5 in deepwater. About $440 million of our capital budget for 2007 has been allocated to our Gulf of Mexico program. Our activities in the traditional shelf are helping to maintain production levels while generating significant cash flow to fund other growth areas.

International. In recent years, we have invested increasing amounts in international operations. Recent field developments offshore Malaysia and China and in the U.K. North Sea are expected to add significant production in 2007. Our planned investment in international ventures for 2007 is expected to be more than $200 million.

In 2007, our activities in Malaysia will focus on bringing our Abu Field on-line. In addition, development continues at the Puteri Field on PM 318 and the East Belumut and Chermingat Fields on PM 323. Offshore China, our drilling program for the Bohai Bay will focus on development of our two commercial fields, where production commenced in the middle of 2006. In the U.K. North Sea, our Grove Field is being prepared for production. We plan to drill three exploration prospects in the North Sea in 2007. Under an agreement signed in 2006, a significant portion of the costs associated with these exploration prospects will be funded by another company. The first of the three wells has been drilled and was unsuccessful.

Please see the discussion under the caption Forward-Looking Information in Item 7 of this report.

Marketing

Substantially all of our natural gas and oil production is sold to a variety of purchasers under short-term (less than 12 months) contracts at market sensitive prices. For a list of purchasers of our oil and gas production that accounted for 10% or more of our consolidated revenue for the three preceding calendar years, please see Note 1, Organization and Summary of Significant Accounting Policies *Major Customers*, to our consolidated financial statements. We believe that the loss of any of these purchasers would not have a material adverse effect on us because alternative purchasers of this production are readily available.

Competition

Competition in the oil and gas industry is intense, particularly access to drilling rigs and other services, the acquisition of properties and the hiring and retention of technical personnel. For a further discussion, please see the information set forth under the caption *Competitive industry conditions may negatively affect our ability to conduct operations* in Item 1A of this report.

Employees

As of February 15, 2007, we had 871 employees. All but 70 of our employees were located in the U.S. None of our employees are covered by a collective bargaining agreement. We believe that relationships with our employees are satisfactory.

Regulation

For a discussion of the significant governmental regulations to which our business is subject, please see the information set forth under the caption Regulation in Item 7 of this report.

Item 1A. ***Risk Factors***

An investment in our securities involves risks. You should carefully consider, in addition to the other information contained in this report, the risks described below.

Oil and gas prices fluctuate widely, and lower prices for an extended period of time are likely to have a material adverse impact on our business. Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas. These prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount that we can borrow under our credit facility could be limited by changing expectations of future prices. In addition, lower prices may reduce the amount of oil and gas that we can economically produce.

Among the factors that can cause fluctuations are:

- the domestic and foreign supply of oil and natural gas;
- the price and availability of alternative fuels;
- disruptions in supply and changes in demand caused by weather conditions;
- changes in demand as a result of changes in price;
- the price of foreign imports;
- world-wide economic conditions;
- political conditions in oil and gas producing regions; and
- domestic and foreign governmental regulations.

Our future success depends on our ability to find, develop and acquire oil and gas reserves. Most of our producing properties have declining production rates. To maintain production levels, we must locate and develop or acquire new oil and gas reserves to replace those depleted by production. Without successful exploration or acquisition activities, our reserves, production and revenues will decline rapidly. We may be unable to find and develop or acquire additional reserves at an acceptable cost. In addition, substantial capital is required to replace and grow reserves. If lower oil and gas prices or operating constraints or production difficulties result in our cash flow from operations being less than expected or limit our ability to borrow under our credit arrangements, we may be unable to expend the capital necessary to locate and develop or acquire new oil and gas reserves.

Our use of oil and gas price hedging contracts involves credit risk and may limit future revenues from price increases. We generally hedge a substantial, but varying, portion of our anticipated future oil and natural gas production for the next 12-24 months as part of our risk management program. In the case of acquisitions, we may hedge acquired production for a longer period. We use hedging to reduce price volatility, help ensure that we have adequate cash flow to fund our capital programs and manage price risks and returns on some of our acquisitions and drilling programs. While the use of hedging transactions limits the downside risk of price declines, their use also may limit future revenues from price increases. Hedging transactions also involve the risk that the counterparty may be unable to satisfy its obligations.

Actual quantities of recoverable oil and gas reserves and future cash flows from those reserves most likely will vary from our estimates. Estimating accumulations of oil and gas is complex. The process relies on interpretations of available geologic, geophysic, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

The proved reserve information set forth in this report is based on estimates we prepared. Estimates prepared by others might differ materially from our estimates.

Actual quantities of recoverable oil and gas reserves, future production, oil and gas prices, revenues, taxes, development expenditures and operating expenses most likely will vary from our estimates. Any significant variance could materially affect the quantities and net present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development and prevailing oil and gas prices. Our reserves also may be susceptible to drainage by operators on adjacent properties.

You should not assume that the present value of future net cash flows is the current market value of our estimated proved oil and gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on prices and costs in effect at December 31. Actual future prices and costs may be materially higher or lower than the prices and costs we used.

If oil and gas prices decrease, we may be required to take writedowns. We may be required to writedown the carrying value of our oil and gas properties when oil and gas prices decrease or if we have substantial downward adjustments to our estimated proved reserves, increases in our estimates of operating or development costs or deterioration in our exploration results.

We capitalize the costs to acquire, find and develop our oil and gas properties under the full cost accounting method. The net capitalized costs of our oil and gas properties may not exceed the present value of estimated future net cash flows from proved reserves, using period-end oil and gas prices and a 10% discount factor, plus the lower of cost or fair market value for unproved properties. If net capitalized costs of our oil and gas properties exceed this limit, we must charge the amount of the excess to earnings. We review the carrying value of our properties quarterly, based on prices in effect (including the effect of our hedging contracts that are designated for hedge accounting) as of the end of each quarter or as of the time of reporting our results. The carrying value of oil and gas properties is computed on a country-by-country basis. Therefore, while our properties in one country may be subject to a writedown, our properties in other countries could be unaffected. Once recorded, a writedown of oil and gas properties is not reversible at a later date even if oil and gas prices increase.

We may not achieve production growth from our Monument Butte Field. In August 2004, we acquired the 100,000-acre Monument Butte Field located in the Uinta Basin of Northeast Utah for approximately $575 million. The crude oil produced in the Uinta Basin is known as black wax because it has a higher paraffin content than crude oil found in most other major North American basins. Currently, area refineries have limited capacity to refine this type of crude oil. As a result we curtailed some production from the field in 2006. In early 2007, we reached agreements with two refiners that secure base load capacity of approximately 11,000 BOPD of capacity through 2008 and 7,400 BOPD through 2009. We are working with other area refiners to secure additional capacity. Without additional refining capacity, our ability to increase production from the field will be limited. In addition, the price we receive for our production from the field has been adversely affected by the increased availability of black wax and other competitive crude oil in the market.

Waterflooding, a secondary recovery operation that involves the injection of large volumes of water into an oil-producing reservoir, is necessary to recover the oil reserves in the Monument Butte Field. In 2006, we signed a water source agreement with the Duchesne Conservancy Water District that secures access to approximately 62,000 barrels of water per day through May 2051. This agreement provides sufficient water for our current operations and will permit some future growth but our ability to significantly increase production from the field may be limited if we do not obtain additional sources of water in the future.

Competition for experienced technical personnel may negatively impact our operations or financial results. Our continued drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced explorationists, engineers and other professionals. Competition for these professionals is extremely intense. We are likely to continue to experience increased costs to attract and retain these professionals.

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We may be unable to obtain the drilling rigs or support services necessary for our drilling and development programs in a timely manner or at acceptable rates. In periods of increased drilling activity resulting from high commodity prices, demand exceeds availability for drilling rigs, drilling vessels, dive boats, supply boats and experienced personnel. The market for oilfield services is currently very competitive. This may lead to difficulty and delays in consistently obtaining services and equipment from vendors, obtaining drilling rigs and other equipment at acceptable rates, and scheduling equipment fabrication at factories and fabrication yards. This, in turn, may lead to projects being delayed or experiencing increased costs.

The oil and gas exploration and production industry is very competitive, and some of our exploration and production competitors have greater financial and other resources than we do. The oil and gas business is highly competitive in the search for and acquisition of reserves. Our competitors include major oil and gas companies, independent oil and gas companies, financial buyers and individual producers. Some of our competitors may have greater and more diverse resources than we do. Recently, higher commodity prices and stiff competition for acquisitions have significantly increased the cost of available properties.

We may be subject to risks in connection with acquisitions. The successful acquisition of producing properties requires an assessment of several factors, including:

recoverable reserves;

future oil and gas prices and their appropriate differentials;

operating costs; and

potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every platform or well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an as is basis.

Drilling is a high-risk activity. Our future success will depend on the success of our drilling programs. In addition to the numerous operating risks described in more detail below, these activities involve the risk that no commercially productive oil or gas reservoirs will be encountered. In addition, we often are uncertain as to the future cost or timing of drilling, completing and producing wells. Furthermore, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

shortages or delays in the availability of drilling rigs and the delivery of equipment;

adverse weather conditions;

unexpected drilling conditions;

pressure or irregularities in formations;

equipment failures or accidents; and

compliance with governmental requirements.

The oil and gas business involves many operating risks that can cause substantial losses; insurance may not protect us against all these risks. These risks include:

fires;

explosions;

blow-outs;

- uncontrollable flows of oil, gas, formation water or drilling fluids;
- natural disasters;
- pipe or cement failures;
- casing collapses;
- embedded oilfield drilling and service tools;
- abnormally pressured formations; and
- environmental hazards such as oil spills, natural gas leaks, pipeline ruptures, discharges of toxic gases and build up of naturally occurring radioactive materials.

If any of these events occur, we could incur substantial losses as a result of:

- injury or loss of life;
- severe damage or destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- investigatory and clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations; and
- repairs to resume operations.

If we experience any of these problems, our ability to conduct operations could be adversely affected.

Offshore operations are subject to a variety of operating risks, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can and have caused substantial damage to facilities and interrupt production. Our operations in the Gulf of Mexico are dependent upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. Any significant change affecting these infrastructure facilities could materially harm our business. We deliver crude oil and natural gas through gathering systems and pipelines that we do not own. These facilities may be temporarily unavailable due to adverse weather conditions or may not be available to us in the future. As a result, we could incur substantial liabilities or experience reductions in revenue that could reduce or eliminate the funds available for our exploration and development programs and acquisitions, or result in the loss of properties.

We maintain insurance against some, but not all, of these potential risks and losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. As a result of the damage caused by hurricanes in 2005, insurance coverage for these types of storms is limited. Where available, the cost of this insurance coverage may be excessive relative to the risks presented.

Exploration in deepwater involves greater operating and financial risks than exploration at shallower depths. These risks could result in substantial losses. Deepwater drilling and operations require the application of recently developed technologies and involve a higher risk of mechanical failure. We will likely experience significantly higher drilling costs in connection with the deepwater wells that we drill. In addition, much of the deepwater play lacks the physical and oilfield service infrastructure present in shallower waters. As a result, development of a deepwater discovery may be a lengthy process and require substantial capital investment, resulting in significant financial and operating risks.

In addition, we may not serve as the operator of significant projects in which we invest. As a result, we may have limited ability to exercise influence over operations related to these projects or their associated costs. Our dependence on the operator and other working interest owners for these deepwater projects and our limited ability to influence operations and associated costs could prevent the realization of our targeted returns on capital. The success and timing of drilling and development activities on properties operated by others therefore depend upon a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel;
- the operator s expertise and financial resources;
- approval of other participants in drilling wells; and
- selection of technology.

We are subject to complex laws that can affect the cost, manner or feasibility of doing business. Exploration and development and the production and sale of oil and gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with environmental and other governmental regulations. Matters subject to regulation include:

- the amounts and type of substances and materials that may be released into the environment;
- reports and permits concerning exploration, drilling, production and other operations;
- the spacing of wells;
- unitization and pooling of properties;
- calculating royalties on oil and gas produced under federal and state leases; and
- taxation.

Under these laws, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs, natural resource damages and other environmental damages. We could also be required to install expensive pollution control measures or limit or cease activities on lands located within wilderness, wetlands or other environmentally or politically sensitive areas. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties as well as the imposition of corrective action orders. Moreover, these laws could change in ways that substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could have a material adverse effect on our financial condition, results of operations or cash flows.

We have risks associated with our foreign operations. We currently have international activities and we continue to evaluate and pursue new opportunities for international expansion in select areas. Ownership of property interests and production operations in areas outside the United States is subject to the various risks inherent in foreign operations. These risks may include:

- currency restrictions and exchange rate fluctuations;
- loss of revenue, property and equipment as a result of expropriation, nationalization, war or insurrection;

- increases in taxes and governmental royalties;
- renegotiation of contracts with governmental entities and quasi-governmental agencies;
- changes in laws and policies governing operations of foreign-based companies;
- labor problems; and
- other uncertainties arising out of foreign government sovereignty over our international operations.

Our international operations also may be adversely affected by the laws and policies of the United States affecting foreign trade, taxation and investment. In addition, if a dispute arises with respect to our foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of the courts of the United States.

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Our certificate of incorporation, bylaws, stockholder rights plan and some of our arrangements with employees contain provisions that could discourage an acquisition or change of control of our company. Our stockholder rights plan, together with certain provisions of our certificate of incorporation and bylaws, may make it more difficult to effect a change of control of our company, to acquire us or to replace incumbent management. In addition, our change of control severance plan and agreements, our omnibus stock plans and our incentive compensation plan contain provisions that provide for severance payments and accelerated vesting of benefits, including accelerated vesting of restricted stock and options, upon a change of control. These provisions could discourage or prevent a change of control or reduce the price our stockholders receive in an acquisition of our company.

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

Concentration

Our 10 largest fields accounted for approximately 57% of our proved reserves at year-end 2006. The largest of those fields, the Monument Butte Field, accounted for about 19% of our proved reserves and about 16% of the net present value of our proved reserves at December 31, 2006. Since 2000, we have diversified our asset base, and, as a result, our reserves are more evenly distributed across our focus areas.

Mid-Continent

We have a sizeable presence in the Anadarko and Arkoma Basins. As of December 31, 2006, we owned an interest in more than 825,000 gross acres and about 3,100 gross producing wells. Approximately 130,000 net acres are associated with our Woodford Shale play. The Mid-Continent accounted for approximately 35% of our proved reserves at December 31, 2006. We operate 91% of those reserves.

Onshore Gulf Coast

As of December 31, 2006, we owned an interest in nearly 300,000 gross acres and about 650 gross producing wells primarily along the Gulf Coast of Texas. The onshore Gulf Coast accounted for nearly 20% of our proved reserves at December 31, 2006. We operate about 76% of those reserves.

Rocky Mountains

As of December 31, 2006, we owned an interest in about 221,000 gross acres, 900 gross producing wells and 400 water injection wells. The vast majority of our assets in the Rocky Mountains are in our Monument Butte Field, located in the Uinta Basin of northeastern Utah. We operate 100% of our reserves in the Monument Butte Field. In early 2007, we closed several transactions that added 100,000 gross acres near our Monument Butte Field. The Rocky Mountain division accounted for approximately 20% of our proved reserves at year-end 2006.

Gulf of Mexico

As of December 31, 2006, we owned interests in about 290 leases on the shelf and 70 leases in deepwater (approximately 1.8 million gross acres) and about 617 gross producing wells. We operate about 75% of our Gulf of Mexico reserves. The Gulf of Mexico accounted for approximately 15% of our proved reserves at year-end 2006.

International

At year-end 2006, approximately 10% of our total proved reserves were located internationally.

Malaysia. Through three production sharing contracts, or PSCs, we own interests in three blocks offshore Malaysia. We own a 50% non-operated interest in PM 318 and a 60% operated interest in PM 323. Both blocks

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are located in shallow water offshore Peninsular Malaysia. PM 318 covers approximately 414,000 gross acres and had gross production of about 7,000 BOPD at year-end 2006. On the same block, we are developing the Abu Field and the 2005 Puteri discovery. PM 323 covers 320,000 acres and has four undeveloped discoveries. Also, we are developing the East Belumut and Chermingat Fields. Offshore Sarawak, we own a 40% operated interest in deepwater Block 2C, a 1.1 million acre area. No production exists on this acreage.

China. We have oil production from two fields on Block 05/36 in Bohai Bay, offshore China. These fields are within a 22,000 gross acre unit in which we have a 12% interest. First production from the fields commenced during 2006. In late 2005, we signed agreements to explore on two blocks offshore Hong Kong in the Pearl River Mouth Basin. We acquired seismic data across portions of the acreage in 2006. The two blocks cover more than 2 million gross acres.

North Sea. Our 2005 Grove discovery is being prepared for production. The field is located on license area 49/10a. We have an 85% interest in this field. At December 31, 2006, we owned interests in about 168,000 gross acres in the U.K. sector.

Proved Reserves and Future Net Cash Flows

The following table shows our estimated net proved oil and gas reserves and the present value of estimated future after-tax net cash flows related to those reserves as of December 31, 2006.

	Proved Reserves		
	Developed	**Undeveloped**	**Total**
United States:			
Oil and condensate (MMBbls)	61	32	93
Gas (Bcf)	1,094	441	1,535
Total proved reserves (Bcfe)	1,459	633	2,092
Present value of estimated future after-tax net cash flows (in millions)(1)			$ 3,186
International:			
Oil and condensate (MMBbls)	4	17	21
Gas (Bcf)		51	51
Total proved reserves (Bcfe)	25	155	180
Present value of estimated future after-tax net cash flows (in millions)(1)			$ 261
Total:			
Oil and condensate (MMBbls)	65	49	114
Gas (Bcf)	1,094	492	1,586
Total proved reserves (Bcfe)	1,484	788	2,272
Present value of estimated future after-tax net cash flows (in millions)(1)			$ 3,447

(1) This measure was prepared using year-end oil and gas prices applicable to our reserves and cash flows discounted at 10% per year. Weighted average year-end prices were $5.36 per Mcf for gas and $51.49 per Bbl for oil. This calculation does not include the effects of hedging. For a further description of how this measure is determined, see Supplementary Financial Information Supplementary Oil and Gas Disclosures Unaudited Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves.

All reserve information in this report is based on estimates prepared by our petroleum engineering staff. As a requirement of our credit facility, independent reserve engineers prepare separate reserve reports with respect to properties holding at least 70% of the present value of our proved reserves. At December 31, 2006, the independent reserve engineers reports covered properties representing 83% of our proved reserves and

87% of the present value. For such properties, the reserves reported by the independent reserve engineers were within 3% of the reserves we reported. Actual quantities of recoverable reserves and future cash flows from those reserves most likely will vary from the estimates set forth above. Reserve and cash flow estimates rely on interpretations of data and require many assumptions that may turn out to be inaccurate. For a discussion of these interpretations and assumptions, see *Actual quantities of recoverable oil and gas reserves and future cash flows from those reserves most likely will vary from our estimates* under Item 1A of this report.

Drilling Activity

The following table sets forth our drilling activity for each year in the three-year period ended December 31, 2006.

	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
United States:						
Productive(1)	420	290.5	390	296.3	211	151.8
Nonproductive(2)	36	21.1	32	23.3	22	13.9
China:						
Productive	14	1.7				
Nonproductive						
United Kingdom:						
Productive(3)	2	1.7	1	1.0		
Nonproductive(4)			1	0.6	1	1.0
Malaysia:						
Productive(5)	10	4.9	4	2.0		
Nonproductive(6)	3	1.6	2	1.0		
International Total:						
Productive	26	8.3	5	3.0		
Nonproductive	3	1.6	3	1.6	1	1.0
Exploratory Well Total	485	321.5	430	324.2	234	166.7
Development wells:						
United States:						
Productive	199	183.2	135	116.1	43	37.1
Nonproductive	3	2.7	1	1.0	1	1.0
Development Well Total	202	185.9	136	117.1	44	38.1

(1) Includes 62 gross (52.6 net), 27 gross (17.5 net) and 23 gross (14.1 net) wells in 2006, 2005 and 2004, respectively, that are not exploitation wells.

(2) Includes 16 gross (10.8 net), 16 gross (10.0 net) and 17 gross (11.0 net) wells in 2006, 2005 and 2004, respectively, that are not exploitation wells.

(3) The well in 2005 is not an exploitation well.

(4) These wells are not exploitation wells.

(5) Includes 2 gross (0.9 net) and 1 gross (0.5 net) wells in 2006 and 2005, respectively, that are not exploitation wells.

(6) Includes 2 gross (1.1 net) and 2 gross (1.0 net) wells in 2006 and 2005, respectively, that are not exploitation wells.

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We were in the process of drilling 25 gross (20.4 net) exploratory wells (includes 22 gross (18.3 net) exploitation wells) and five gross (3.9 net) development wells in the United States, two gross (0.2 net) exploitation wells in China, one gross (0.5 net) development well in Malaysia and one gross (0.9 net) development well in the United Kingdom at December 31, 2006.

Productive Wells

The following table sets forth the number of productive oil and gas wells in which we owned an interest as of December 31, 2006 and the location of, and other information with respect to, those wells.

	Company Operated Wells		Outside Operated Wells		Total Productive Wells	
	Gross	Net	Gross	Net	Gross	Net
United States:						
Gulf of Mexico:						
Oil	92	64.9	10	2.2	102	67.1
Gas	395	274.8	120	36.5	515	311.3
Louisiana:						
Oil	5	4.3			5	4.3
Gas	19	12.0	14	4.5	33	16.5
Texas:						
Oil	32	26.9	16	5.1	48	32.0
Gas	536	486.6	288	116.5	824	603.1
Oklahoma:						
Oil	323	239.5	588	21.4	911	260.9
Gas	1,315	1,139.1	589	109.8	1,904	1,248.9
Utah:						
Oil	1,356	1,140.7	9	2.9	1,365	1,143.6
Gas	20	15.0			20	15.0
Other domestic:						
Oil	3	2.8	2	0.7	5	3.5
Gas	10	7.2	24	4.3	34	11.5
Total domestic:						
Oil	1,811	1,479.1	625	32.3	2,436	1,511.4
Gas	2,295	1,934.7	1,035	271.6	3,330	2,206.3
International:						
Offshore China:						
Oil			15	1.8	15	1.8
Offshore Malaysia:						
Oil			10	5.0	10	5.0
Total International:						
Oil			25	6.8	25	6.8

Total:						
Oil	1,811	1,479.1	650	39.1	2,461	1,518.2
Gas	2,295	1,934.7	1,035	271.6	3,330	2,206.3
Total	4,106	3,413.8	1,685	310.7	5,791	3,724.5

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The day-to-day operations of oil and gas properties are the responsibility of an operator designated under pooling or operating agreements or production sharing contracts. The operator supervises production, maintains production records, employs or contracts for field personnel and performs other functions. Generally, an operator receives reimbursement for direct expenses incurred in the performance of its duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged by unaffiliated third parties. The charges customarily vary with the depth and location of the well being operated.

Acreage Data

As of December 31, 2006, we owned interests in developed and undeveloped oil and gas acreage in the locations set forth in the table below. Domestic ownership interests generally take the form of working interests in oil and gas leases that have varying terms. International ownership interests generally arise from participation in production sharing contracts.

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
	(In thousands)			
United States:				
Gulf of Mexico:				
Shelf	717	398	253	136
Treasure Project			479	167
Deepwater	46	9	259	114
Total Gulf of Mexico	763	407	991	417
Onshore:				
Louisiana	4	2	1	
Texas	173	104	186	130
Oklahoma	562	328	188	114
Utah	39	32	94	61
Other domestic	15	6	92	79
Total onshore	793	472	561	384
Total domestic	1,556	879	1,552	801
International:				
Offshore Brazil			206	206
Offshore China	22	3	2,266	2,266
Offshore Malaysia	15	8	1,814	970
Offshore United Kingdom			168	146
Total international	37	11	4,454	3,588
Total	1,593	890	6,006	4,389

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The table below summarizes by year and geographic area our undeveloped acreage scheduled to expire in the next five years. In most cases, the drilling of a commercial well, or the filing and approval of a development plan or suspension of operations, will hold acreage beyond the expiration date. We own fee mineral interests in 317,811 gross (99,380 net) undeveloped acres. These interests do not expire.

	Undeveloped Acres Expiring (In thousands)									
	2007		2008		2009		2010		2011	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States:										
Gulf of Mexico:										
Shelf	41	20	69	49	32	18	26	24	15	15
Treasure Project	30	8	263	69	57	17	41	11	5	1
Deepwater	58	26	6	1			35	12	17	13
Total Gulf of Mexico	129	54	338	119	89	35	102	47	37	29
Onshore	125	85	138	93	74	53	9	10	52	51
Total domestic	254	139	476	212	163	88	111	57	89	80
International:										
Offshore Brazil	206	206								
Offshore China	510	510			439	439				
Offshore Malaysia					398	199	338	196	1,079	575
Offshore United Kingdom					77	70			20	17
Total international	716	716			914	708	338	196	1,099	592
Total	970	855	476	212	1,077	796	449	253	1,188	672

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry in the case of undeveloped properties, often little investigation of record title is made at the time of acquisition. Investigations are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use, or affect the value, of the properties. Burdens on properties may include:

customary royalty interests;

liens incident to operating agreements and for current taxes;

obligations or duties under applicable laws;

development obligations under oil and gas leases;

burdens such as net profits interests; and

capital commitments under production sharing contracts or exploration licenses.

Item 3. ***Legal Proceedings***

We have been named as a defendant in a number of lawsuits arising in the ordinary course of our business. While the outcome of these lawsuits cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

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

There were no matters submitted to a vote of our security holders during the fourth quarter of 2006.

Item 4A. ***Executive Officers of the Registrant***

The following table sets forth the names and ages (as of February 28, 2007) of and positions held by our executive officers. Our executive officers serve at the discretion of our Board of Directors.

Name	Age	Position	Total Years of Service with Newfield
David A. Trice	58	Chairman, President and Chief Executive Officer and a Director	12
David F. Schaible	46	Executive Vice President Operations and Acquisitions and a Director	17
Terry W. Rathert	54	Senior Vice President, Chief Financial Officer and Secretary	17
Michael D. Van Horn	55	Senior Vice President Exploration	–
W. Mark Blumenshine	48	Vice President Land	5
Mona Leigh Bernhardt	40	Vice President Human Resources	7
Lee K. Boothby	45	Vice President Mid-Continent	7
Stephen C. Campbell	38	Vice President Investor Relations	7
George T. Dunn	49	Vice President Gulf Coast	14
John H. Jasek	37	Vice President Gulf of Mexico	6
James J. Metcalf	49	Vice President Drilling	11
Gary D. Packer	44	Vice President Rocky Mountains	11
William D. Schneider	55	Vice President International	17
Mark J. Spicer	47	Vice President Information Technology	6
James T. Zernell	49	Vice President Production	10
Brian L. Rickmers	38	Controller and Assistant Secretary	13
Susan G. Riggs	49	Treasurer	10

The executive officers have held the positions indicated above for the past five years, except as follows:

David A. Trice was appointed Chairman in September 2004.

David F. Schaible was promoted from Vice President to Executive Vice President in November 2004. He has served as a director since May 2002.

Terry W. Rathert was promoted from Vice President to Senior Vice President in November 2004.

Michael D. Van Horn joined the Company as Senior Vice President in November 2006. He served at EOG Resources, and its predecessor Enron Oil and Gas, since 1993. Most recently, he served as Vice President of

International Exploration. Prior to that position, he was Director of Exploration.

W. Mark Blumenshine was promoted from Manager to Vice President in December 2005.

Mona Leigh Bernhardt was promoted from Manager to Vice President in December 2005.

Lee K. Boothby was promoted to Vice President in November 2004. He has managed our Mid-Continent operations since February 2002.

Stephen C. Campbell was promoted from Manager to Vice President in December 2005.

George T. Dunn was promoted to Vice President in November 2004. He has managed our onshore Gulf Coast operations since 2001.

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John H. Jasek was promoted from General Manager to Vice President in November 2006. He has managed our Gulf of Mexico operations since March 2005. Prior to that, he was a Petroleum Engineer in the Western Gulf of Mexico.

James J. Metcalf was promoted from Manager to Vice President in December 2005.

Gary D. Packer was promoted from a Gulf of Mexico General Manager to Vice President Rocky Mountains in November 2004.

Mark J. Spicer was promoted from Manager to Vice President in December 2005.

James T. Zernell was promoted from Manager to Vice President in December 2005.

PART II

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

Our common stock is listed on the New York Stock Exchange under the symbol NFX. The following table sets forth, for each of the periods indicated, the high and low reported sales price of our common stock on the NYSE.

	High	Low
2005		
First Quarter	38.43	27.43
Second Quarter	41.28	32.03
Third Quarter	50.90	39.00
Fourth Quarter	53.52	39.98
2006		
First Quarter	54.50	35.07
Second Quarter	51.75	38.65
Third Quarter	49.72	34.99
Fourth Quarter	50.16	34.90
2007		
First Quarter (Through February 26, 2007)	45.36	39.30

On February 26, 2007, the last reported sales price of our common stock on the NYSE was $44.20 per share.

As of February 26, 2007, there were approximately 1,900 holders of record of our common stock.

We completed a two-for-one split of our common stock following the close of trading on May 25, 2005. The split was effected by a common stock dividend.

We have not paid any cash dividends on our common stock and do not intend to do so in the foreseeable future. We intend to retain earnings for the future operation and development of our business. Any future cash dividends to holders of our common stock would depend on future earnings, capital requirements, our financial condition and other factors determined by our Board of Directors. The covenants contained in our credit facility and in the indenture governing our 65/8% Senior Subordinated Notes due 2014 and 2016 could restrict our ability to pay cash dividends.

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended December 31, 2006.

	Total Number of	Maximum Number (or Approximate) Dollar Value) of

Period	Total Number of Shares Purchased[1]	Average Price Paid per Share	Shares Purchased as Part of Publicly Announced Plans or Programs[2]	Shares that May Yet be Purchased Under the Plans or Programs
October 1 October 31, 2006				
November 1 November 30, 2006				
December 1 December 31, 2006	793	$ 48.00		

(1) All of the shares repurchased were surrendered by employees to pay tax withholding upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced program to repurchase shares of our common stock.

(2) On November 20, 2006, we announced a program pursuant to which stockholders owning fewer than 100 shares of our common stock could sell their shares at no cost to them. We did not purchase any shares under the program but we did pay for the costs to administrate the program. The program expired on January 26, 2007.

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Item 5A. ***Stockholder Return Performance Presentation***

The performance graph shown below is being furnished pursuant to Regulation S-K, Item 201(e). As required by applicable rules of the SEC, the performance graph was prepared based upon the following assumptions:

$100 was invested in our common stock, the S&P 500 Index and our peer group on December 31, 2001 at the closing price on such date;

investment in our peer group was weighted based on the stock market capitalization of each individual company within the peer group at the beginning of the period; and

dividends were reinvested on the relevant payment dates.

Our peer group is comprised of Anadarko Petroleum Corporation, Apache Corporation, Cabot Oil & Gas Corporation; Chesapeake Energy Corporation; EOG Resources, Inc., Forest Oil Corporation, Murphy Oil Corporation, Noble Energy, Inc., Pioneer Natural Resources Company; Pogo Producing Company, St. Mary Land & Exploration Company, Stone Energy Corporation, Swift Energy Company, The Houston Exploration Company and XTO Energy Inc.

Total Return Analysis	**12/31/2001**	**12/31/2002**	**12/31/2003**	**12/31/2004**	**12/31/2005**	**12/31/2006**
Newfield Exploration	$ 100.00	$ 101.52	$ 125.39	$ 166.27	$ 281.93	$ 258.73
Peer Group	$ 100.00	$ 106.06	$ 141.20	$ 186.79	$ 291.45	$ 287.35
S&P 500	$ 100.00	$ 77.95	$ 100.27	$ 111.15	$ 116.60	$ 134.87

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Item 6. ***Selected Financial Data***

SELECTED FIVE-YEAR FINANCIAL AND RESERVE DATA

The following table shows selected consolidated financial data derived from our consolidated financial statements and reserve data derived from our supplementary oil and gas disclosures set forth in Item 8 of this report. The data should be read in conjunction with Item 2, *Properties* Proved Reserves and Future Net Cash Flows and Item 7, *Management s Discussion and Analysis of Financial Condition and Results of Operations*, of this report.

	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(In millions, except per share data)				
Income Statement Data:					
Oil and gas revenues	$ 1,673	$ 1,762	$ 1,353	$ 1,017	$ 627
Income from continuing operations	591	348	312	211	69
Net income	591	348	312	200	74
Earnings per share:					
Basic					
Income from continuing operations	4.67	2.78	2.68	1.94	0.76
Net income	4.67	2.78	2.68	1.83	0.82
Diluted					
Income from continuing operations	4.58	2.73	2.63	1.88	0.76
Net income	4.58	2.73	2.63	1.78	0.81
Weighted average number of shares outstanding for basic earnings per share	127	125	117	109	90
Weighted average number of shares outstanding for diluted earnings per share	129	128	119	113	99
Cash Flow Data:					
Net cash provided by continuing operating activities	$ 1,384	$ 1,109	$ 997	$ 659	$ 383
Net cash used in continuing investing activities	(1,662)	(1,036)	(1,599)	(615)	(502)
Net cash provided by (used in) continuing financing activities	317	(88)	644	(85)	137
Balance Sheet Data (at end of period):					
Total assets	$ 6,635	$ 5,081	$ 4,327	$ 2,733	$ 2,316
Long-term debt	1,048	870	992	643	710
Convertible preferred securities					144
Reserve Data (at end of period):					
Proved reserves:					
Oil and condensate (MMBbls)	114	102	91	38	34
Gas (Bcf)	1,586	1,391	1,241	1,090	977
Total proved reserves (Bcfe)	2,272	2,001	1,784	1,317	1,181

Present value of estimated future after-tax net cash flows	$ 3,447	$ 5,053	$ 3,602	$ 2,935	$ 2,247

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

Overview

We are an independent oil and gas company engaged in the exploration, development and acquisition of crude oil and natural gas properties. Our domestic areas of operation include the onshore Gulf Coast, the Anadarko and Arkoma Basins of the Mid-Continent, the Uinta Basin of the Rocky Mountains and the Gulf of Mexico. Internationally, we are active offshore Malaysia and China and in the U.K. North Sea.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and on our ability to find, develop and acquire oil and gas reserves that are economically recoverable. The preparation of our financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect our reported results of operations and the amount of our reported assets, liabilities and proved oil and gas reserves. We use the full cost method of accounting for our oil and gas activities.

Oil and Gas Prices. Prices for oil and gas fluctuate widely. Oil and gas prices affect:

- the amount of cash flow available for capital expenditures;
- our ability to borrow and raise additional capital;
- the quantity of oil and gas that we can economically produce; and
- the accounting for our oil and gas activities.

We generally hedge a substantial, but varying, portion of our anticipated future oil and gas production as a part of our risk management program. We use hedging to reduce price volatility, help ensure that we have adequate cash flow to fund our capital programs and manage price risks and returns on some of our acquisitions and drilling programs.

Reserve Replacement. Most of our producing properties have declining production rates. As a result, to maintain and grow our production and cash flow we must locate and develop or acquire new oil and gas reserves to replace those being depleted by production. Substantial capital expenditures are required to find, develop and acquire oil and gas reserves.

Significant Estimates. We believe the most difficult, subjective or complex judgments and estimates we must make in connection with the preparation of our financial statements are:

- the quantity of our proved oil and gas reserves;
- the timing of future drilling, development and abandonment activities;
- the cost of these activities in the future;
- the fair value of the assets and liabilities of acquired companies;
- the value of our derivative positions; and

the fair value of stock-based compensation.

Accounting for Hedging Activities. Beginning October 1, 2005, we elected not to designate any future price risk management activities as accounting hedges. Because hedges not designated for hedge accounting are accounted for on a mark-to-market basis, we are likely to experience significant non-cash volatility in our reported earnings during periods of commodity price volatility. Please see Critical Accounting Policies and Estimates *Commodity Derivative Activities*.

Results of Operations

Revenues. All of our revenues are derived from the sale of our oil and gas production, which includes the effects of the settlement of derivative contracts associated with our production that are accounted for as hedges. Settlement of derivative contracts that are not accounted for as hedges has no effect on our reported revenues. Please see Note 5, Commodity Derivative Instruments and Hedging Activities, to our consolidated financial statements appearing later in this report for a discussion of the accounting applicable to our oil and gas derivative contracts.

Our revenues may vary significantly from year to year as a result of changes in commodity prices or volumes of production sold. Revenues of $1.7 billion for 2006 were 5% lower than 2005 revenues due to lower gas prices and lower oil production partially offset by higher oil prices and increased gas production.

	Year Ended December 31,		
	2006	**2005**	**2004**
Production[1]:			
United States:			
Natural gas (Bcf)	198.7	190.9	197.6
Oil and condensate (MBbls)	6,218	7,152	6,686
Total (Bcfe)	236.0	233.7	237.7
International:			
Natural gas (Bcf)		0.1	0.6
Oil and condensate (MBbls)	1,097	1,294	879
Total (Bcfe)	6.6	7.9	5.9
Total:			
Natural gas (Bcf)	198.7	191.0	198.2
Oil and condensate (MBbls)	7,315	8,446	7,565
Total (Bcfe)	242.6	241.6	243.6
Average Realized Prices[2]:			
United States:			
Natural gas (per Mcf)	$ 6.47	$ 7.18	$ 5.40
Oil and condensate (per Bbl)	51.40	44.06	36.61
Natural gas equivalent (per Mcfe)	6.80	7.21	5.52
International:			
Natural gas (per Mcf)	$	$ 4.71	$ 4.38
Oil and condensate (per Bbl)	56.58	55.68	44.26
Natural gas equivalent (per Mcfe)	9.43	9.20	7.07
Total:			
Natural gas (per Mcf)	$ 6.47	$ 7.17	$ 5.39
Oil and condensate (per Bbl)	52.18	45.84	37.50
Natural gas equivalent (per Mcfe)	6.87	7.27	5.55

(1) Represents volumes sold regardless of when produced.

(2) Average realized prices include the effects of hedging other than contracts that are not designated for hedge accounting. Had we included the effect of these contracts, our average realized price for total gas would have been $7.22, $6.65 and $5.36 per Mcf for 2006, 2005 and 2004, respectively. Our total oil and condensate average realized price would have been $50.25, $44.36 and $35.27 per Bbl for 2006, 2005 and 2004, respectively. Without the effects of hedging contracts, our average realized prices for 2006, 2005 and 2004 would have been $6.42, $7.54 and $5.75 per Mcf, respectively, for gas and $59.13, $53.36 and $40.95 per barrel, respectively, for oil.

Production. Our 2006 total oil and gas production (stated on a natural gas equivalent basis) was essentially the same as total production for 2005. Successful drilling efforts in the Mid-Continent were offset by continued Gulf of Mexico production deferrals of approximately 16 Bcfe during 2006 related to Hurricanes Katrina and Rita in 2005, natural field declines and the timing of liftings of oil production in Malaysia. Our 2005 total oil and gas production (stated on a natural gas equivalent basis) decreased 1% from 2004. The decrease was a result of Gulf of Mexico production deferrals of approximately 22 Bcfe related to the 2005 storms offset by a full year s production from our 2004 acquisitions and successful drilling efforts.

Natural Gas. Our 2006 natural gas production increased 4% over 2005. The increase was primarily the result of successful drilling efforts in the Mid-Continent partially offset by continued Gulf of Mexico production deferrals during the first half of 2006 related to the 2005 storms and natural field declines. Our 2005 natural gas production decreased 4% when compared to 2004. The decrease was the result of production deferrals related to the 2005 storms and natural field declines offset by a full year s production from our 2004 acquisitions.

Crude Oil and Condensate. Our 2006 oil and condensate production decreased 13% primarily as a result of the timing of liftings of oil production in Malaysia. Our 2005 oil and condensate production increased 12% when compared to 2004 primarily due to a full year s production from the Inland Resources acquisition and a full year of liftings in Malaysia partially offset by production deferrals related to the 2005 storms.

Operating Expenses. Generally, our proved reserves and production have grown steadily since our founding. As a result, our operating expenses also have increased. We believe the most informative way to analyze changes in our operating expenses from period to period is on a unit-of-production, or per Mcfe, basis.

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Year ended December 31, 2006 compared to December 31, 2005

The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2006.

	Unit-of-Production			Amount		
	Year Ended December 31,		Percentage Increase	Year Ended December 31,		Percentage Increase
	2006	2005	(Decrease)	2006	2005	(Decrease)
	(Per Mcfe)			(In millions)		
United States:						
Lease operating	$ 1.11	$ 0.81	37%	$ 261	$ 190	38%
Production and other taxes	0.21	0.25	(16%)	49	58	(15%)
Depreciation, depletion and amortization	2.59	2.18	19%	611	510	20%
General and administrative	0.49	0.43	14%	116	101	14%
Other	(0.04)	(0.12)	(67%)	(11)	(29)	(63%)
Total operating expenses	4.36	3.55	23%	1,026	830	24%
International:						
Lease operating	$ 2.40	$ 1.90	26%	$ 16	$ 15	5%
Production and other taxes	1.77	0.82	116%	12	6	81%
Depreciation, depletion and amortization	2.00	1.36	47%	13	11	23%
General and administrative	1.28	0.44	191%	8	3	144%
Ceiling test writedown	0.94	1.22	(23%)	6	10	(35%)
Total operating expenses	8.39	5.74	46%	55	45	22%
Total:						
Lease operating	$ 1.14	$ 0.85	34%	$ 277	$ 205	36%
Production and other taxes	0.25	0.26	(4%)	61	64	(5%)
Depreciation, depletion and amortization	2.57	2.15	20%	624	521	20%
General and administrative	0.51	0.43	19%	124	104	18%
Ceiling test writedown	0.03	0.04	(25%)	6	10	(35%)
Other	(0.04)	(0.12)	(67%)	(11)	(29)	(63%)
Total operating expenses	4.46	3.61	24%	1,081	875	24%

Domestic Operations. Our domestic operating expenses for 2006, stated on an Mcfe basis, increased 24% over the same period of 2005. This increase was primarily related to the following items:

Lease operating expense (LOE) increased due to higher operating costs for all of our operations and significantly higher insurance costs for our Gulf of Mexico operations. Additionally, 2006 LOE was impacted by the difference ($0.07 per Mcfe) between insurance proceeds received from the settlement of all claims related to the 2005 hurricanes and actual repair expenditures during 2006. Without the impact of the costs related to the repairs for the 2005 storms in excess of our insured amount, our LOE would have been $1.04 per

Mcfe for 2006.

Production and other taxes decreased primarily due to refunds related to production tax exemptions on certain of our onshore high cost gas wells in Texas.

The increase in our depreciation, depletion and amortization (DD&A) rate resulted from higher cost reserve additions. The cost of reserve additions was adversely impacted by escalating costs of drilling goods and services experienced during 2006. The component of DD&A associated with accretion expense related to our asset retirement obligation was $0.06 per Mcfe for 2006 and 2005. Please see

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Note 1, Organization and Summary of Significant Accounting Policies *Asset Retirement Obligations*, to our consolidated financial statements.

General and administrative (G&A) expense increased approximately $0.06 per Mcfe primarily due to stock-based compensation expense recognized as a result of our adoption of Statement of Financial Accounting Standards (SFAS) No. 123(R) on January 1, 2006. Please see Note 11, Stock-based Compensation, to our consolidated financial statements. The increase attributable to stock-based compensation expense was partially offset by a decrease in incentive compensation expense as a result of lower adjusted net income (as defined in our incentive compensation plan) in 2006 as compared to the prior year. Adjusted net income for purposes of our incentive compensation plan excludes unrealized gains and losses on commodity derivatives. During 2006, we capitalized $40 million of direct internal costs as compared to $38 million in 2005.

Other expenses for 2006 and 2005 include the following items:

In 2006, we redeemed all $250 million of our 83/8% Senior Subordinated Notes due 2012. We recorded a charge for the $19 million early redemption premium we paid and a charge of $8 million for the remaining unamortized original issuance costs related to the notes. In addition, we recorded a $37 million benefit from our business interruption insurance coverage in 2006 relating to the disruptions to our operations caused by the 2005 storms.

In 2005, we recorded a $22 million benefit from our business interruption insurance coverage and sold our interest in the floating production system and related equipment we acquired in the EEX transaction for a net gain of $7 million.

International Operations. Our international operating expenses for 2006, stated on an Mcfe basis, increased 46% over 2005. The increase was primarily related to the following items:

LOE increased because our production in Malaysia decreased while total LOE remained relatively unchanged. Our Malaysian LOE primarily consists of fixed costs related to our FPSO.

Production and other taxes increased as a result of higher crude oil prices.

DD&A increased as a result of higher cost reserve additions in Malaysia and initial liftings of oil production in China during the third quarter of 2006.

G&A expense increased due to stock compensation expense recognized as a result of the adoption of SFAS No. 123(R) on January 1, 2006 and growth in our international workforce.

We recorded a ceiling test writedown of $6 million associated with ceasing our exploration efforts in Brazil in 2006. In 2005, we recorded a ceiling test writedown of $10 million associated with our decreased emphasis on exploration efforts in Brazil and in other non-core international regions.

Year ended December 31, 2005 compared to December 31, 2004

The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2005.

	Unit-of-Production Year Ended December 31, 2005	(Per Mcfe) 2004	Percentage Increase (Decrease)	Amount Year Ended December 31, 2005	(In millions) 2004	Percentage Increase (Decrease)
United States:						
Lease operating	$ 0.81	$ 0.60	35%	$ 190	$ 143	33%
Production and other taxes	0.25	0.17	47%	58	40	44%
Depreciation, depletion and amortization	2.18	1.95	12%	510	463	10%
General and administrative	0.43	0.34	26%	101	82	24%
Other	(0.12)	0.15	(180%)	(29)	35	(181%)
Total operating expenses	3.55	3.21	11%	830	763	9%
International:						
Lease operating	$ 1.90	$ 1.59	19%	$ 15	$ 9	61%
Production and other taxes	0.82	0.38	116%	6	2	183%
Depreciation, depletion and amortization	1.36	1.37	(1%)	11	9	35%
General and administrative	0.44	0.43	2%	3	2	36%
Ceiling test writedown	1.22	2.90	(58%)	10	17	(44%)
Total operating expenses	5.74	6.67	(14%)	45	39	15%
Total:						
Lease operating	$ 0.85	$ 0.63	35%	$ 205	$ 152	35%
Production and other taxes	0.26	0.17	53%	64	42	51%
Depreciation, depletion and amortization	2.15	1.94	11%	521	472	10%
General and administrative	0.43	0.34	26%	104	84	24%
Ceiling test writedown	0.04	0.07	(43%)	10	17	(44%)
Other	(0.12)	0.14	(186%)	(29)	35	(181%)
Total operating expenses	3.61	3.29	10%	875	802	9%

Domestic Operations. Our domestic operating expenses for 2005, stated on an Mcfe basis, increased 11% over the same period of 2004. This increase was primarily related to the following items:

LOE was adversely impacted by deferred production of approximately 22 Bcfe related to the 2005 storms, higher operating costs, increased well workover activity and natural field declines in our Gulf of Mexico properties.

Production and other taxes increased due to higher commodity prices and an increase in the proportion of our production volumes subject to production taxes as a result of our acquisition of the Monument Butte Field, increased production from our Mid-Continent and onshore Gulf Coast operations and storm related deferrals in the Gulf of Mexico.

The increase in our DD&A rate resulted from higher cost reserve additions. The component of DD&A associated with accretion expense related to our asset retirement obligation was $0.06 per Mcfe and $0.05 per Mcfe for 2005 and 2004, respectively.

The increase in G&A expense was primarily due to growth in our workforce as a result of acquisitions and an increase in incentive compensation as a result of higher adjusted net income (as defined in our incentive compensation plan) in 2005 as compared to the prior year. Adjusted net income for purposes of our incentive compensation plan excludes unrealized gains and losses on commodity derivatives. During 2005, we capitalized $38 million of direct internal costs as compared to $30 million in 2004.

Other expenses for 2005 and 2004 include the following items:

In December 2005, we recorded a $22 million benefit related to our business interruption insurance coverage as a result of the disruptions in our operations caused by Hurricanes Katrina and Rita.

As a result of our acquisition of EEX Corporation in November 2002, we owned a 60% interest in a floating production system, some offshore pipelines and a processing facility located at the end of the pipelines in shallow water. At the time of acquisition, we estimated the fair value of these assets to be $35 million. Since their acquisition, we had undertaken to sell these assets. In December 2004, when what we believed was the last commercial opportunity for sale was not realized, we determined that there was no active market for these assets. As a result, in connection with the preparation of our financial statements for the year ended December 31, 2004, we recorded an impairment charge of $35 million. In early April 2005, we entered into an agreement with Diamond Offshore Services Company to sell our interest in the floating production facility and related equipment. In August 2005, we closed the sale and received net proceeds of $7 million, which were recorded as a gain on our consolidated statement of income.

International Operations. In May 2004, we entered into PSCs with Malaysia s state-owned oil company with respect to two offshore blocks. Liftings of oil production began in August 2004. Prior thereto, our producing international operations consisted of one field in the U.K. North Sea, which we sold in June 2005.

The increase in LOE primarily resulted from a full year of operations in Malaysia in 2005.

Production and other taxes increased due to the significant increase in oil prices during 2005.

A ceiling test writedown of $10 million associated with our decreased emphasis on exploration efforts in Brazil and in other non-core international regions was recorded in December 2005. In 2004, we recorded a ceiling test writedown of $17 million associated with a dry hole in the U.K. North Sea.

Interest Expense. The following table presents information about our interest expense for each of the years in the three-year period ended December 31, 2006.

	Year Ended December 31,		
	2006	2005	2004
	(In millions)		
Gross interest expense	$ 87	$ 72	$ 58
Capitalized interest	(44)	(46)	(26)
Net interest expense	$ 43	$ 26	$ 32

The increase in gross interest expense in 2006 resulted primarily from the April 13, 2006 issuance of $550 million principal amount of our 65/8% Senior Subordinated Notes due 2016, partially offset by the May 3, 2006 redemption of $250 million principal amount of our 83/8% Senior Subordinated Notes due 2012. The 2005 increase is primarily due to an entire year of accrued interest related to our 65/8% Senior Subordinated Notes due 2014 issued in August 2004 in connection with our acquisition of the Monument Butte Field.

During the second half of 2004, we financed the cash consideration for our acquisitions of properties in Oklahoma and the Gulf of Mexico (aggregating approximately $226 million) primarily with borrowings under our credit arrangements. By the end of the second quarter of 2005, we had repaid all of the borrowings under our credit arrangements for the 2004 acquisitions.

We capitalize interest with respect to unproved properties. Interest capitalized increased in 2005 over 2004 primarily due to an increase in our unproved property base as a result of the Inland Resources acquisition in late August 2004.

Commodity Derivative Income (Expense). The following table presents information about the components of commodity derivative income (expense) for each of the years in the three-year period ended December 31, 2006.

	Year Ended December 31,		
	2006	2005	2004
	(In millions)		
Cash flow hedges:			
Hedge ineffectiveness	$ 5	$ (8)	$ 4
Other derivative contracts:			
Realized (loss) on settlement of discontinued cash flow hedges		(51)	
Unrealized gain (loss) due to changes in fair market value	249	(202)	(4)
Realized gain (loss) on settlement	135	(61)	(24)
Total commodity derivative income (expense)	$ 389	$ (322)	$ (24)

Hedge ineffectiveness is associated with our hedging contracts that qualify for hedge accounting under SFAS No. 133. As a result of the production deferrals experienced in the Gulf of Mexico related to Hurricanes Katrina and Rita, hedge accounting was discontinued during the third quarter of 2005 on a portion of our contracts that had previously qualified as effective cash flow hedges of our Gulf of Mexico production and other contracts were redesignated as hedges of our onshore Gulf Coast production. As a result, realized losses of $51 million associated with derivative contracts for the third and fourth quarters of 2005, which were in excess of hedged physical deliveries for those periods, were reported as commodity derivative expense. The unrealized gain (loss) due to changes in fair market value is associated with our derivative contracts that are not designated for hedge accounting and represents changes in the fair value of these open contracts during the period.

Taxes. The effective tax rates for the years ended December 31, 2006, 2005 and 2004 were 38%, 36% and 37%, respectively. Our effective tax rate was more than the federal statutory tax rate for all three years primarily due to state income taxes and the excess of the Malaysia and U.K. statutory tax rates over the U.S. federal statutory rate. In addition, our effective tax rate for 2006 increased as a result of an $18 million ($15 million U.K. and $3 million Brazilian) valuation allowance for deferred tax assets related to net operating loss carryforwards in those countries that are not expected to be realized. The $15 million U.K. valuation allowance is due to a substantial decrease in estimated future taxable income as a result of the disappointing results of the recent #7 well in our Grove field in the U.K. North Sea.

Our effective tax rate for the year 2005 was less than our effective tax rate for 2004 primarily due to the realization of a net change of $5 million in our valuation allowance for tax assets related to certain of our international operations. An $8 million valuation allowance related to our U.K. net operating loss carryforwards was reversed in 2005 as a result of a substantial increase in estimated future taxable income as a result of our 2005 Grove discovery in the U.K. North Sea. In 2005, we recorded a $3 million valuation allowance for various international and Brazilian deferred tax assets related to net operating loss carryforwards that were not expected to be realized.

Estimates of future taxable income can be significantly affected by changes in oil and natural gas prices, the timing and amount of future production and future operating expenses and capital costs.

Liquidity and Capital Resources

We must find new and develop existing reserves to maintain and grow production and cash flow. We accomplish this through successful drilling programs and the acquisition of properties. These activities require substantial capital expenditures. Over the long-term, we have successfully grown our reserve base and production, resulting in growth in our net cash flows from operating activities. Fluctuations in commodity prices and the 2005 hurricanes have been the primary reason for short-term changes in our cash flow from operating activities.

In August 2006, we reached an agreement with our insurance underwriters to settle all claims related to Hurricanes Katrina and Rita (business interruption, property damage and control of well/operator s extra expense) for $235 million.

We establish a capital budget at the beginning of each calendar year based in part on expected cash flow from operations for that year. In the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. Because of the nature of the properties we own, contractual capital commitments beyond 2007 are not significant. Our 2007 capital budget exceeds currently expected cash flow from operations by approximately $350 million. We anticipate that the shortfall will be made up with cash and short-term investments on hand and borrowings under our credit arrangements.

On October 15, 2007, our 7.45% Senior Notes with an aggregate principal amount of $125 million become due. We currently plan to fund the repayment with borrowings under our credit arrangements.

Credit Arrangements. In December 2005, we entered into a revolving credit facility that matures in December 2010. Our credit facility provides for initial loan commitments of $1 billion from a syndication of participating banks, led by JPMorgan Chase as the agent bank. The loan commitments may be increased to a maximum aggregate amount of $1.5 billion if the current lenders increase their loan commitments or new financial institutions are added to the credit facility. Loans under our credit facility bear interest, at our option, based on (a) a rate per annum equal to the higher of the prime rate or the weighted average of the rates on overnight federal funds transactions during the last preceding business day plus 50 basis points or (b) a base Eurodollar rate, substantially equal to the London Interbank Offered Rate, plus a margin that is based on a grid of our debt rating (100 basis points per annum at December 31, 2006). At February 26, 2007, we had no outstanding borrowings and $52 million of undrawn letters of credit under our credit facility.

The credit facility has restrictive covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed 0.6 to 1.0; maintenance of a ratio of total debt to earnings before gain or loss on the disposition of assets, interest expense, income taxes, depreciation, depletion and amortization expense, exploration and abandonment expense and other noncash charges and expenses to consolidated interest expense of at least 3.5 to 1.0; and, as long as our debt rating is below investment grade, the maintenance of an annual ratio of the net present value of our oil and gas properties to total debt of at least 1.75 to 1.00. At December 31, 2006, we were in compliance with all of our debt covenants.

We also have a total of $110 million of borrowing capacity under money market lines of credit with various banks. At February 26, 2007, we had outstanding borrowings of $45 million under our money market lines.

As of February 26, 2007, we had approximately $951 million of available borrowing capacity under our credit arrangements.

Working Capital. Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements. Generally, we use excess cash to pay down borrowings under our credit arrangements. As a result, we often have a working capital deficit or a relatively small amount of positive working capital. We had a working capital deficit of $272 million as of December 31, 2006. This compares to working capital deficits of $130 million at the end of 2005 and $82 million at the end of 2004. The majority of the working capital deficit at December 31, 2006 relates to the reclassification of our $125 million 7.45% Senior Notes due October 15, 2007 as a current liability and an increase in accrued liabilities as a result of our significant capital activities towards the end of 2006. The increase in accrued liabilities is due to our increased exploration and development activity and higher service costs over 2005. Our working capital balances are also affected by fluctuations in the fair value of our outstanding commodity derivative instruments. At December 31, 2006, the fair value of our short-term derivatives was a net asset of $200 million. At December 31, 2005, this amount was a net short-term derivative liability of $89 million. At December 31, 2004, the fair value of our short-term derivatives was a net asset of $8 million (see Note 5, Commodity Derivative Instruments and Hedging Activities, to our consolidated financial statements). Our 2006 working capital deficit also includes $40 million in asset retirement obligations compared to $47 million in 2005 and $23 million in 2004 (see Note 1, Organization and Summary of Significant Accounting Policies *Asset Retirement Obligations*, to our consolidated financial statements).

Cash Flows from Operations. Cash flows from operations are primarily affected by production and commodity prices, net of the effects of settlements of our derivative contracts. Our cash flows from operations also are impacted by changes in working capital. We sell substantially all of our natural gas and oil production under floating market contracts. However, we enter into commodity hedging arrangements to reduce our exposure to fluctuations in natural gas and oil prices, to help ensure that we have adequate cash flow to fund our capital programs and to manage price risks and returns on some of our acquisitions and drilling programs. See Item 7A, *Quantitative and Qualitative Disclosures About Market Risk.* We typically receive the cash associated with accrued oil and gas sales within 45-60 days of production. As a result, cash flows from operations and income from operations generally correlate, but cash flows from operations is impacted by changes in working capital and is not affected by DD&A, writedowns or other non-cash charges or credits.

Our net cash flow from operations was $1,384 million in 2006, a 25% increase over the prior year. The increase was primarily due to 2006 realized oil and gas prices (on a natural gas equivalent basis), including the effects of hedging contracts (regardless of whether designated for hedge accounting), which increased 9% over 2005. See Results of Operations above.

Our net cash flows from operations were $1,109 million in 2005, an 11% increase over the prior year. Although our 2005 production volumes were impacted by the 2005 storms, higher commodity prices offset the cash flow impact of the deferred production. Realized oil and gas prices (on a natural gas equivalent basis), including the effects of hedging contracts (regardless of whether designated for hedge accounting), increased 25% over 2004. See Results of Operations above.

Capital Expenditures. Our 2006 capital spending was $1,890 million, a 69% increase from our 2005 capital spending of $1,119 million. These amounts exclude recorded asset retirement obligations of $16 million in 2006 and $44 million in 2005. During 2006, we invested $1,161 million in domestic exploitation and development, $379 million in domestic exploration (exclusive of exploitation and leasehold activity), $71 million in other domestic leasehold activity and $279 million internationally.

Our 2005 capital spending was $1,119 million, a 38% decrease from our 2004 capital spending of $1,796 million (excluding recorded asset retirement obligations of $48 million). During 2005, we invested $696 million in domestic exploitation and development, $257 million in domestic exploration (exclusive of exploitation and leasehold activity), $81 million in other domestic leasehold activity and $85 million internationally.

We budgeted $1.8 billion for capital spending in 2007, excluding acquisitions. This total includes $50 million for continuing hurricane repairs in the Gulf of Mexico and excludes $100 million for capitalized interest and overhead. Approximately 24% of the $1.8 billion is allocated to the Gulf of Mexico (including the traditional shelf, the deep and ultra-deep shelf and deepwater), 19% to the onshore Gulf Coast, 38% to the Mid-Continent, 8% to the Rocky Mountains and 11% to international projects. See Item 1, *Business* Plans for 2007. Since our 2007 capital budget exceeds currently forecasted cash flow, we plan to make up the shortfall with borrowings under our credit arrangements. Actual levels of capital expenditures may vary significantly due to many factors, including the extent to which proved properties are acquired, drilling results, oil and gas prices, industry conditions and the prices and availability of goods and services. We continue to pursue attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable. Historically, with the exception of 2006, we have completed several acquisitions of varying sizes each year. Depending on the timing of an acquisition, we may spend additional capital during the year of the acquisition for drilling and development activities on the acquired properties.

Cash Flows from Financing Activities. Net cash flows provided by financing activities for 2006 were $317 million compared to $88 million of net cash flows used in financing activities for 2005.

In October 2007, our $125 million principal amount 7.45% Senior Notes will become due. We currently anticipate repaying these notes with borrowings under our credit arrangements.

During 2006, we:

issued $550 million aggregate principal amount of our 65/8% Senior Subordinated Notes due 2016;

used the proceeds from this offering to redeem $250 million principal amount of our 83/8% Senior Subordinated Notes due 2012;

borrowed and repaid $519 million under our credit arrangements; and

received proceeds of $15 million from the issuance of shares of our common stock.

During 2005, we:

repaid a net $120 million under our credit arrangements; and

received proceeds of $32 million from the issuance of shares of our common stock.

Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of December 31, 2006.

	Total	Less Than 1 Year	1-3 Years (In millions)	4-5 Years	More Than 5 Years
Debt:					
7.45% Senior Notes due 2007	$ 125	$ 125	$	$	$
75/8% Senior Notes due 2011	175			175	
65/8% Senior Subordinated Notes due 2014	325				325
65/8% Senior Subordinated Notes due 2016	550				550
Total debt	1,175	125		175	875
Other obligations:					
Interest payments	566	79	214	118	155
Net derivative (assets) liabilities	(44)	(203)	159		
Asset retirement obligations	272	40	94	34	104
Operating leases[1]	190	80	91	8	11
Deferred acquisition payments[2]	9	3	4	2	
Oil and gas activities[3]	257				
Total other obligations	1,250	(1)	562	162	270
Total contractual obligations	$ 2,425	$ 124	$ 562	$ 337	$ 1,145

(1) See Note 14, Commitments and Contingencies *Lease Commitments*, to our consolidated financial statements.

(2) See Note 3, Acquisitions, to our consolidated financial statements.

(3) See *Oil and Gas Activities* below.

Oil and Gas Activities. As is common in the oil and gas industry, we have various contractual commitments pertaining to exploration, development and production activities. We have work related commitments for, among other things, drilling wells, obtaining and processing seismic data and fulfilling other cash commitments. At December 31, 2006, these work related commitments total $257 million and are comprised of $160 million in the United States and $97 million internationally. These amounts are not included by maturity because their timing cannot be accurately predicted.

Credit Arrangements. Please see Liquidity and Capital Resources *Credit Arrangements* above for a description of our revolving credit facility and money market lines of credit.

Senior Notes. In October 1997, we issued $125 million aggregate principal amount of our 7.45% Senior Notes due 2007. In February 2001, we issued $175 million aggregate principal amount of our 75/8% Senior Notes due 2011. Interest on our senior notes is payable semi-annually.

Our senior notes are unsecured and unsubordinated obligations and rank equally with all of our other existing and future unsecured and unsubordinated obligations. We may redeem some or all of our senior notes at any time before their maturity at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. The indentures governing our senior notes contain covenants that limit our ability to, among other things:

incur debt secured by certain liens;

enter into sale/leaseback transactions; and

enter into merger or consolidation transactions.

The indentures also provide that if any of our subsidiaries guarantee any of our indebtedness at any time in the future, then we will cause our senior notes to be equally and ratably guaranteed by that subsidiary.

During the third quarter of 2003, we entered into interest rate swap agreements that provide for us to pay variable and receive fixed interest payments and are designated as fair value hedges of a portion of our senior notes (see Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* and Note 8, Debt *Interest Rate Swaps*, to our consolidated financial statements).

Senior Subordinated Notes. In August 2004, we issued $325 million aggregate principal amount of our 65/8% Senior Subordinated Notes due 2014. In April 2006, we issued $550 million aggregate principal amount of our 65/8% Senior Subordinated Notes due 2016. Interest on our senior subordinated notes is payable semi-annually. The notes are unsecured senior subordinated obligations that rank junior in right of payment to all of our present and future senior indebtedness.

We may redeem some or all of our 65/8% notes due 2014 at any time on or after September 1, 2009 and some or all of our 65/8% notes due 2016 at any time on or after April 15, 2011, in each case, at a redemption price stated in the applicable indenture governing the notes. We also may redeem all but not part of our 65/8% notes due 2014 prior to September 1, 2009 and all but not part of our 65/8% notes due 2016 prior to April 15, 2011, in each case, at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. In addition, before September 1, 2007, we may redeem up to 35% of the original principal amount of our 65/8% notes due 2014 with the net cash proceeds from certain sales of our common stock at 106.625% of the principal amount plus accrued and unpaid interest to the date of redemption. Likewise, before April 15, 2009, we may redeem up to 35% of the original principal amount of our 65/8% notes due 2016 with similar net cash proceeds at 106.625% of the principal amount plus accrued and unpaid interest to the date of redemption.

The indenture governing our senior subordinated notes limits our ability to, among other things:

incur additional debt;

make restricted payments;

pay dividends on or redeem our capital stock;

make certain investments;

create liens;

make certain dispositions of assets;

engage in transactions with affiliates; and

engage in mergers, consolidations and certain sales of assets.

Commitments under Joint Operating Agreements. Most of our properties are operated through joint ventures under joint operating or similar agreements. Typically, the operator under a joint operating agreement enters into contracts, such as drilling contracts, for the benefit of all joint venture partners. Through the joint operating agreement, the non-operators reimburse, and in some cases advance, the funds necessary to meet the contractual obligations entered into by the operator. These obligations are typically shared on a working interest basis. The joint operating agreement provides remedies to the operator if a non-operator does not satisfy its share of the contractual obligations. Occasionally, the operator is permitted by the joint operating agreement to enter into lease obligations and other contractual commitments that are then passed on to the non-operating joint interest owners as lease operating expenses, frequently without any identification as to the long-term nature of any commitments underlying such expenses.

Oil and Gas Hedging

We generally hedge a substantial, but varying, portion of our anticipated future oil and natural gas production for the next 12-24 months as part of our risk management program. In the case of acquisitions, we may hedge acquired production for a longer period. We use hedging to reduce price volatility, help ensure that we have adequate cash flow to fund our capital programs and manage price risks and returns on some of our acquisitions and drilling programs. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. Approximately 57% of our 2006 production was subject to derivative contracts (including both contracts that are designated and not designated for hedge accounting). In 2005, 81% of our production was subject to derivative contracts, compared to 72% in 2004.

While the use of hedging arrangements limits the downside risk of adverse price movements, they also may limit future revenues from favorable price movements. In addition, the use of hedging transactions may involve basis risk. Substantially all of our hedging transactions are settled based upon reported settlement prices on the NYMEX. Historically, all of our hedged natural gas and crude oil production has been sold at market prices that have had a high positive correlation to the settlement price for such hedges. Therefore, we believe that our hedged production is not subject to material basis risk. The price that we receive for natural gas production from the Gulf of Mexico and onshore Gulf Coast, after basis differentials, transportation and handling charges, typically averages $0.40 - $0.60 less per MMBtu than the Henry Hub Index. Realized gas prices for our Mid-Continent properties, after basis differentials, transportation and handling charges, typically average $0.70 - $0.80 less per MMBtu than the Henry Hub Index. The price we receive for our Gulf Coast oil production typically averages about $2 per barrel below the NYMEX West Texas Intermediate (WTI) price. The price we receive for our oil production in the Rocky Mountains is currently averaging about $13 - $15 per barrel below the WTI price. Oil production from the Mid-Continent typically sells at a $1.00 - $1.50 per barrel discount to WTI. Oil production from our operations in Malaysia typically sells at Tapis, or about even with WTI. Oil sales from our operations in China are currently averaging about $15 per barrel less than the WTI.

The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. At December 31, 2006, Bank of Montreal, JPMorgan Chase, Citibank, N.A. and J Aron & Company were the counterparties with respect to 73% of our future hedged production.

Please see the discussion and tables in Note 5, Commodity Derivative Instruments and Hedging Activities, to our consolidated financial statements for a description of the accounting applicable to our hedging program and a listing of open contracts as of December 31, 2006 and the fair value of those contracts as of that date.

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Between January 1, 2007 and February 26, 2007, we entered into additional natural gas price derivative contracts set forth in the table below.

		NYMEX Contract Price per MMBtu				
			Collars			
		Swaps	Floors		Ceilings	
Period and Type of Contract	Volume in MMMBtus	(Weighted Average)	Range	Weighted Average	Range	Weighted Average
January 2007 March 2007						
Price swap contracts	590	$ 7.16				
April 2007 June 2007						
Price swap contracts	1,820	7.70				
July 2007 September 2007						
Price swap contracts	1,230	7.77				
October 2007 December 2007						
Price swap contracts	920	8.80				
Collar contracts	8,235		$ 8.00	$ 8.00	$ 10.00 - $11.85	$ 10.68
January 2008 March 2008						
Price swap contracts	910	9.29				
Collar contracts	12,285		8.00	8.00	10.00 - 11.85	10.68
April 2008 June 2008						
Price swap contracts	1,820	7.67				
July 2008 September 2008						
Price swap contracts	1,840	7.67				
October 2008 December 2008						
Price swap contracts	620	7.67				

None of the contracts above have been designated for hedge accounting.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions, or for any other purpose. However, as is customary in the oil and gas industry, we have various contractual work commitments as described above under Contractual Obligations *Oil and Gas Activities*.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Described below are the most significant policies we apply in preparing our financial statements, some of which are subject to alternative treatments under generally accepted accounting principles. We also describe the most significant estimates and assumptions we make in applying these policies. We discussed the development, selection and disclosure of each of these with the Audit Committee of our Board of Directors.

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See Results of Operations above and Note 1, Organization and Summary of Significant Accounting Policies, to our consolidated financial statements for a discussion of additional accounting policies and estimates we make.

For discussion purposes, we have divided our significant policies into four categories. Set forth below is an overview of each of our significant accounting policies by category.

We account for our oil and gas activities under the full cost method. This method of accounting requires the following significant estimates:

- quantity of our proved oil and gas reserves;
- costs withheld from amortization; and
- future costs to develop and abandon our oil and gas properties.

Accounting for business combinations requires estimates and assumptions regarding the value of the assets and liabilities of the acquired company.

Accounting for commodity derivative activities requires estimates and assumptions regarding the value of derivative positions.

Stock-based compensation cost requires estimates and assumptions regarding the grant date fair value of awards, the determination of which requires significant estimates and subjective judgements.

Oil and Gas Activities

Accounting for oil and gas activities is subject to special, unique rules. Two generally accepted methods of accounting for oil and gas activities are available successful efforts and full cost. The most significant differences between these two methods are the treatment of exploration costs and the manner in which the carrying value of oil and gas properties are amortized and evaluated for impairment. The successful efforts method requires exploration costs to be expensed as they are incurred while the full cost method provides for the capitalization of these costs. Both methods generally provide for the periodic amortization of capitalized costs based on proved reserve quantities. Impairment of oil and gas properties under the successful efforts method is based on an evaluation of the carrying value of individual oil and gas properties against their estimated fair value, while impairment under the full cost method requires an evaluation of the carrying value of oil and gas properties included in a cost center against the net present value of future cash flows from the related proved reserves, using period-end prices and costs and a 10% discount rate.

Full Cost Method. We use the full cost method of accounting for our oil and gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties are capitalized into cost centers (the amortization base) that are established on a country-by-country basis. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. Capitalized costs also include salaries, employee benefits, costs of consulting services and other expenses that are estimated to directly relate to our oil and gas activities. Interest costs related to unproved properties also are capitalized. Although some of these costs will ultimately result in no additional reserves, we expect the benefits of successful wells to more than offset the costs of any unsuccessful ones. Costs associated with production and general corporate activities are expensed in the period incurred. The capitalized costs of our oil and gas properties, plus an estimate of our future development costs, are amortized on a unit-of-production method based on our estimate of total proved reserves. Amortization is calculated separately on a country-by-country basis. Our financial position and results of operations would have been significantly different had we used the successful efforts method of accounting for our oil and gas activities.

Proved Oil and Gas Reserves. Our engineering estimates of proved oil and gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization expense and the full cost ceiling limitation. Proved oil and gas reserves are the estimated quantities of natural gas and crude oil reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under period-end economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The data for a given reservoir may change substantially over time as a result of numerous factors including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil and gas prices, operating costs and expected performance from a given reservoir also will result in revisions to the amount of our estimated proved reserves.

All reserve information in this report is based on estimates prepared by our petroleum engineering staff. As a requirement of our revolving credit facility, independent reserve engineers prepare separate reserve reports with respect to properties holding at least 70% of the present value of our proved reserves. For December 31, 2006, the independent reserve engineers reports covered properties representing 83% of our proved reserves and 87% of the present value. For such properties, the reserves reported by the independent reserve engineers were within 3% of the reserves we reported.

Depreciation, Depletion and Amortization. Estimated proved oil and gas reserves are a significant component of our calculation of depletion expense and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves are revised upward, earnings would increase due to lower depletion expense. Likewise, if reserves are revised downward, earnings would decrease due to higher depletion expense or due to a ceiling test writedown. To increase our domestic DD&A rate by $0.01 per Mcfe for 2006 would require a decrease in our estimated proved reserves at December 31, 2005 of approximately 13 Bcfe. Due to the relatively small size of our international full cost pools for the U.K., Malaysia and China, any decrease in reserves associated with the respective country s full cost pool would significantly increase the DD&A rate in that country. However, since production from our International operations represented less than 5% of our consolidated production for 2006, a change in our international DD&A expense would not have materially affected our consolidated results of operations.

Full Cost Ceiling Limitation. Under the full cost method, we are subject to quarterly calculations of a ceiling or limitation on the amount of costs associated with our oil and gas properties that can be capitalized on our balance sheet. If net capitalized costs exceed the applicable cost center ceiling, we are subject to a ceiling test writedown to the extent of such excess. If required, it would reduce earnings and stockholders equity in the period of occurrence and result in lower amortization expense in future periods. The ceiling limitation is applied separately for each country in which we have oil and gas properties. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated prices of oil and natural gas reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that prices and costs in effect as of the last day of the quarter are held constant. However, we may not be subject to a writedown if prices increase subsequent to the end of a quarter in which a writedown might otherwise be required. The full cost ceiling test impairment calculations also take into consideration the effects of hedging contracts that are designated for hedge accounting. Given the fluctuation of natural gas and oil prices, it is reasonably possible that the estimated discounted future net cash flows from our proved reserves will change in the near term. If natural gas and oil prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that writedowns of our oil and gas properties could occur in the future.

At December 31, 2006, the ceiling value of our domestic oil and gas reserves was calculated based upon quoted market prices of $5.64 per MMBtu for gas and $61.05 per barrel for oil, adjusted for market differentials. Using these prices, the unamortized net capitalized costs of our domestic oil and gas properties would have exceeded the ceiling amount by approximately $5 million (net of tax) at December 31, 2006. However, on February 22, 2007, the market price for gas (Gas Daily Henry Hub) increased to $7.48 per MMBtu and the market price for oil (Platt s WTI at Cushing) decreased to $60.95 per barrel. Utilizing these prices, the unamortized costs of our domestic oil and gas properties would not have exceeded the ceiling amount at December 31, 2006. As a result, we did not record a writedown in the fourth quarter of 2006. The ceiling with respect to our oil and gas properties in the U.S. using the

February 22, 2007 prices exceeded the net capitalized costs of those properties by approximately $900 million.

At December 31, 2006, the ceiling with respect to our oil and gas properties in Malaysia, the U.K. and China exceeded the net capitalized costs of the properties by approximately $68 million, $11 million and $19 million, respectively. Due to the relatively small size of these international pools, holding all other factors constant, if the applicable index for natural gas prices were to decline to approximately $4.80 per Mcf and/or oil prices were to decline to approximately $50 per Bbl, it is possible that we could experience ceiling test writedowns in one or all of these international areas.

Costs Withheld From Amortization. Costs associated with unevaluated properties are excluded from our amortization base until we have evaluated the properties. The costs associated with unevaluated leasehold acreage and seismic data, wells currently drilling and capitalized interest are initially excluded from our amortization base. Leasehold costs are either transferred to our amortization base with the costs of drilling a well on the lease or are assessed quarterly for possible impairment or reduction in value. Leasehold costs are transferred to our amortization base to the extent a reduction in value has occurred or a charge is made against earnings if the costs were incurred in a country for which a reserve base has not been established. If a reserve base for a country in which we are conducting operations has not yet been established, an impairment requiring a charge to earnings may be indicated through evaluation of drilling results, relinquishing drilling rights or other information.

In addition, a portion of incurred (if not previously included in the amortization base) and future development costs associated with qualifying major development projects may be temporarily excluded from amortization. To qualify, a project must require significant costs to ascertain the quantities of proved reserves attributable to the properties under development (e.g., the installation of an offshore production platform from which development wells are to be drilled). Incurred and future costs are allocated between completed and future work. Any temporarily excluded costs are included in the amortization base upon the earlier of when the associated reserves are determined to be proved or impairment is indicated.

Our decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involve a significant amount of judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and results of drilling on adjacent acreage. At December 31, 2006, our domestic full cost pool had approximately $906 million of costs excluded from the amortization base, including $26 million associated with development costs for our deepwater Gulf of Mexico project known as Glider, located at Green Canyon 247/248. At December 31, 2006, capital costs not subject to amortization include $292 million related to our acquisition of the Monument Butte Field. Due to the significant size of the field, evaluation of the entire amount will require a number of years. Because the application of the full cost ceiling test at December 31, 2006 (before considering the natural gas price increases experienced subsequent to year end) resulted in an excess of the carrying value of our domestic oil and gas properties over the cost-center ceiling, inclusion of some or all of our unevaluated property costs in our amortization base would have further increased the excess of the carrying value over the cost-center ceiling. Utilizing commodity prices in effect as of February 22, 2007, the inclusion of some or all of these unevaluated property costs in our amortization base, without adding any associated reserves, would not have resulted in a ceiling test writedown. However, our future DD&A rate would increase to the extent such costs are transferred without any associated reserves.

Future Development and Abandonment Costs. Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, water depth, reservoir depth and characteristics, market demand for equipment, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and abandonment costs on an annual basis.

The accounting for future abandonment costs is set forth by SFAS No. 143. This standard requires that a liability for the discounted fair value of an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset.

Holding all other factors constant, if our estimate of future abandonment and development costs is revised upward, earnings would decrease due to higher DD&A expense. Likewise, if these estimates are revised downward, earnings would increase due to lower DD&A expense. To increase our domestic DD&A rate by $0.01 per Mcfe for the year ended December 31, 2006 would require an increase in the present value of our estimated future abandonment and development costs at December 31, 2005 of approximately $40 million. Due to the relatively small size of our international full cost pools in the U.K., Malaysia and China, any change in future abandonment or development costs associated with the respective country s full cost pool would significantly change the DD&A rate in that country. However, since production from our International operations represented less than 5% of our consolidated production for 2006, a change in our international DD&A expense would not have materially affected our consolidated results of operations.

Allocation of Purchase Price in Business Combinations

As part of our growth strategy, we actively pursue the acquisition of oil and gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and gas reserves and unproved properties. To the extent the consideration paid exceeds the fair value of the net assets acquired, we are required to record the excess as an asset called goodwill. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain. The value allocated to recoverable oil and gas reserves and unproved properties is subject to the cost center ceiling as described under *Full Cost Ceiling Limitation* above.

Goodwill of each reporting unit (each country is a separate reporting unit) is tested for impairment on an annual basis, or more frequently if an event occurs or circumstances change that would reduce the fair value of the reporting unit below its carrying amount. In making this assessment, we rely on a number of factors including operating results, business plans, economic projections and anticipated cash flows. As there are inherent uncertainties related to these factors and our judgment in applying them to the analysis of goodwill impairment, there is risk that the carrying value of our goodwill may be overstated. If it is overstated, such impairment would reduce earnings during the period in which the impairment occurs and would result in a corresponding reduction to goodwill. We elected to make December 31 our annual assessment date.

Commodity Derivative Activities

We utilize derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future natural gas and oil production. We generally hedge a substantial, but varying, portion of our anticipated oil and natural gas production for the next 12-24 months. In the case of acquisitions, we may hedge acquired production for a longer period. We do not use derivative instruments for trading purposes. Under accounting rules, we may elect to designate those derivatives that qualify for hedge accounting as cash flow hedges against the price that we will receive for our future oil and natural gas production. To the extent that changes in the fair values of the cash flow hedges offset changes in the expected cash flows from our forecasted production, such amounts are not included in our consolidated results of operations. Instead, they are recorded directly to stockholders equity until the hedged oil or natural gas quantities are produced and sold. To the extent that changes in the fair values of the derivative exceed the changes in the expected cash flows from the forecasted production, the changes are recorded in income in the period in which they occur. Derivatives that do not qualify (such as three-way collar contracts see Note 5, Commodity Derivative Instruments and Hedging Activities, to our consolidated financial statements) or have not been designated as cash flow hedges for hedge accounting are carried at their fair value on our consolidated balance sheet. We recognize all changes in the fair value of these contracts on our consolidated statement of income in the period in which the changes occur. Beginning on October 1, 2005, we elected not to designate any future price risk management activities as accounting hedges. Because derivative contracts not designated for hedge accounting are accounted for on a mark-to-market basis, we are likely to experience significant non-cash volatility in our reported earnings during periods of commodity price volatility.

In determining the amounts to be recorded for cash flow hedges, we are required to estimate the fair values of both the derivative and the associated hedged production at its physical location. Where necessary, we adjust NYMEX prices to other regional delivery points using our own estimates of future regional prices. Our estimates are based upon various factors that include closing prices on the NYMEX, over-the-counter quotations, volatility and the time value of options. The calculation of the fair value of our option contracts requires the use of an option-pricing model. The estimated future prices are compared to the prices fixed by the hedge agreements and the resulting estimated future cash inflows or outflows over the lives of the hedges are discounted to calculate the fair value of the derivative contracts. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts, regional price differences and interest rates. We periodically validate our valuations using independent, third-party quotations.

Stock-Based Compensation

Effective January 1, 2006, we adopted SFAS No. 123 (revised 2004), Share-Based Payment, (SFAS No. 123(R)) to account for stock-based compensation. Under this method, compensation cost is measured at the grant date based on the fair value of an award and is recognized over the service period, which is usually the vesting period. We elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. The determination of the fair value of an award requires significant estimates and subjective judgments regarding, among other things, the appropriate option pricing model, the expected life of the award and performance vesting criteria assumptions. As there are inherent uncertainties related to these factors and our judgment in applying them to the fair value determinations, there is risk that the recorded stock compensation may not accurately reflect the amount ultimately earned by the employee. For years prior to 2006, we accounted for our stock-based compensation in accordance with the intrinsic value method. Under this method, we recognized compensation cost as the excess, if any, of the quoted market price of our stock at the grant date over the amount an employee must pay to acquire the stock. Please see Note 1, Organization and Summary of Significant Accounting Policies *Stock-Based Compensation*, to our consolidated financial statements.

New Accounting Standard

In July 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes, an interpretation of SFAS No. 109, Accounting for Income Taxes. FIN 48 prescribes a comprehensive model for how companies should recognize, measure, present and disclose in their financial statements uncertain tax positions taken or expected to be taken on a tax return. Under FIN 48, tax positions are recognized in our consolidated financial statements as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement with tax authorities assuming full knowledge of the position and all relevant facts. These amounts are subsequently reevalvated and changes are recognized as adjustments to current period tax expense. FIN 48 also revises disclosure requirements to include an annual tabular rollforward of unrecognized tax benefits. We are required to adopt FIN 48 on January 1, 2007. Upon adoption, we will be required to apply the provisions of FIN 48 to all tax positions and any cumulative effect adjustment will be recognized as an adjustment to retained earnings. We have completed our initial evaluation of the impact of FIN 48 and determined that its adoption is not expected to have a material impact on our financial position or results of operations.

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Regulation

Exploration and development and the production and sale of oil and natural gas are subject to extensive federal, state, local and international regulation. An overview of this regulation is set forth below. We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Please see the discussion under the caption *We are subject to complex laws that can affect the cost, manner or feasibility of doing business* in Item 1A of this report.

Federal Regulation of Sales and Transportation of Natural Gas. Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated pursuant to several laws enacted by Congress and the regulations promulgated under these laws by the FERC. In the past, the federal government has regulated the prices at which gas could be sold. Congress removed all price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993. Congress could, however, reenact price controls in the future.

Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive federal and state regulation. From 1985 to the present, several major regulatory changes have been implemented by Congress and the FERC that affect the economics of natural gas production, transportation and sales. In addition, the FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies, that remain subject to the FERC s jurisdiction. These initiatives also may affect the intrastate transportation of gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect more light-handed regulation.

The ultimate impact of the complex rules and regulations issued by the FERC since 1985 cannot be predicted. In addition, some aspects of these regulatory developments have not become final but are still pending judicial and FERC final decisions. We cannot predict what further action the FERC will take on these matters. Some of the FERC s more recent proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any action taken materially differently than other natural gas producers, gatherers and marketers with which we compete.

The Outer Continental Shelf Lands Act, or OCSLA, requires that all pipelines operating on or across the shelf provide open-access, non-discriminatory service. There are currently no regulations implemented by the FERC under its OCSLA authority on gatherers and other entities outside the reach of its Natural Gas Act jurisdiction. Therefore, we do not believe that any FERC or MMS action taken under OCSLA will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers with which we compete.

On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 (2005 EPA). This comprehensive act contains many provisions that will encourage oil and gas exploration and development in the U.S. The 2005 EPA directs the FERC, MMS and other federal agencies to issue regulations that will further the goals set out in the 2005 EPA. We believe that neither the 2005 EPA nor the regulations promulgated, or to be promulgated, as a result of the 2005 EPA will affect us in a way that materially differs from the way they affect other natural gas producers, gatherers and marketers with which we compete.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Federal Regulation of Sales and Transportation of Crude Oil. Our sales of crude oil and condensate are currently not regulated. In a number of instances, however, the ability to transport and sell such products are dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. Certain regulations implemented by the FERC in recent years could result in an increase in the cost of transportation service on certain petroleum products pipelines. However, we do not believe that these regulations affect us any differently than other crude oil and condensate producers.

Federal Leases. Most of our oil and gas leases in Utah and the Gulf of Mexico are granted by the federal government and administered by the MMS or the BLM, both federal agencies. MMS and BLM leases contain relatively standardized terms and require compliance with detailed BLM or MMS regulations and, in the case of offshore leases, orders pursuant to OCSLA (which are subject to change by the MMS). Many onshore leases contain stipulations limiting activities that may be conducted on the lease. Some stipulations are unique to particular geographic areas and may limit the time during which activities on the lease may be conducted, the manner in which certain activities may be conducted or, in some cases, may ban surface activity. For offshore operations, lessees must obtain MMS approval for exploration, development and production plans prior to the commencement of such operations. In addition to permits required from other agencies (such as the Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency), lessees must obtain a permit from the BLM or the MMS, as applicable, prior to the commencement of drilling, and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the Shelf and removal of facilities. To cover the various obligations of lessees on the Shelf, the MMS generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be met. The cost of such bonds or other surety can be substantial and there is no assurance that bonds or other surety can be obtained in all cases. We are currently exempt from the supplemental bonding requirements of the MMS. Under certain circumstances, the BLM or the MMS, as applicable, may require that our operations on federal leases be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition, cash flows and results of operations.

The MMS regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases provide that the MMS will collect royalties based upon the market value of oil produced from federal leases. The 2005 EPA formalizes the royalty in-kind program of the MMS, providing that the MMS may take royalties in-kind if the Secretary of the Interior determines that the benefits are greater than or equal to the benefits that are likely to have been received had royalties been taken in value. We believe that the MMS royalty in-kind program will not have a material effect on our financial position, cash flows or results of operations.

In 2006, the MMS amended its regulations to require additional filing fees. The MMS has estimated that these additional filing fees will represent less than 0.1% of the revenues of companies with offshore operations in most cases. We do not believe that these additional filing fees will affect us in a way that materially differs from the way they affect other producers, gatherers and marketers with which we compete.

State and Local Regulation of Drilling and Production. We own interests in properties located onshore in Louisiana, Texas, New Mexico, Oklahoma and Utah. We also own interests in properties in state waters offshore Texas and Louisiana. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Some states prorate production to the market demand for oil and gas.

Environmental Regulations. Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. The cost of compliance could be significant. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial and damage payment obligations, or the issuance of injunctive relief (including orders to cease operations). Environmental laws and regulations are complex, change frequently and have tended to become more stringent over time. We also are subject to various environmental permit requirements. Both onshore and offshore drilling in certain areas has been opposed by environmental groups and, in certain areas, has been restricted. Moreover, some environmental laws and regulations may impose strict liability, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties. To the extent laws are enacted or other governmental action is taken that prohibits or restricts onshore or offshore drilling or imposes environmental protection requirements that result in increased costs to the oil and gas industry in general, our business and prospects could be adversely affected.

The Oil Pollution Act, or OPA, imposes regulations on responsible parties related to the prevention of oil spills and liability for damages resulting from spills in U.S. waters. A responsible party includes the owner or operator of an onshore facility, vessel or pipeline, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns strict, joint and several liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation, or if the party fails to report a spill or to cooperate fully in the cleanup. Even if applicable, the liability limits for offshore facilities require the responsible party to pay all removal costs, plus up to $75 million in other damages for offshore facilities and up to $350 million for onshore facilities. Few defenses exist to the liability imposed by OPA. Failure to comply with ongoing requirements or inadequate cooperation during a spill event may subject a responsible party to administrative, civil or criminal enforcement actions.

OPA also requires operators in the Gulf of Mexico to demonstrate to the MMS that they possess available financial resources that are sufficient to pay for costs that may be incurred in responding to an oil spill. Under OPA and implementing MMS regulations, responsible parties are required to demonstrate that they possess financial resources sufficient to pay for environmental cleanup and restoration costs of at least $10 million for an oil spill in state waters and at least $35 million for an oil spill in federal waters. Since we currently have extensive operations in federal waters, we currently provide a total of $150 million in financial assurance to MMS.

In addition to OPA, our discharges to waters of the U.S. are further limited by the federal Clean Water Act, or CWA, and analogous state laws. The CWA prohibits any discharge into waters of the United States except in compliance with permits issued by federal and state governmental agencies. Failure to comply with the CWA, including discharge limits set by permits issued pursuant to the CWA, may also result in administrative, civil or criminal enforcement actions. The OPA and CWA also require the preparation of oil spill response plans and spill prevention, control and countermeasure or SPCC plans. We have such plans in existence and are currently amending these plans or, as necessary, developing new SPCC plans that will satisfy new SPCC plan certification and implementation requirements that become effective in July 2009.

OCSLA authorizes regulations relating to safety and environmental protection applicable to lessees and permittees operating on the Shelf. Specific design and operational standards may apply to vessels, rigs, platforms, vehicles and structures operating or located on the Shelf. Violations of lease conditions or regulations issued pursuant to OCSLA can result in substantial administrative, civil and criminal penalties, as well as potential court injunctions curtailing operations and the cancellation of leases.

The Resource Conservation and Recovery Act, or RCRA, generally regulates the disposal of solid and hazardous wastes and imposes certain environmental cleanup obligations. Although RCRA specifically excludes from the definition of hazardous waste drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy, the U.S. Environmental Protection Agency, also known as the EPA and state agencies may regulate these wastes as solid wastes. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

The Comprehensive Environmental Response, Compensation, and Liability Act, also known as CERCLA or the "Superfund" law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on persons that are considered to have contributed to the release of a "hazardous substance into the environment. Such responsible persons may be subject to joint and several liability under the Superfund law for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We currently own or lease onshore properties that have been used for the exploration and production of oil and gas for a number of years. Many of these onshore properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and any wastes that may have been disposed or released on them may be subject to the Superfund law, RCRA and analogous state laws and common law obligations, and we potentially could be required to investigate and remediate such properties, including soil or groundwater contamination by prior owners or operators, or to perform remedial plugging or pit closure operations to prevent future contamination.

The Clean Air Act (CAA) and comparable state statutes restricts the emission of air pollutants and affects both onshore and offshore oil and gas operations. New facilities may be required to obtain separate construction and operating permits before construction work can begin or operations may start, and existing facilities may be required to incur capital costs in order to remain in compliance. Also, the EPA has developed and continues to develop more stringent regulations governing emissions of toxic air pollutants. These regulations may increase the costs of compliance for some facilities.

The Occupational Safety and Health Act (OSHA) and comparable state statutes regulate the protection of the health and safety of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

International Regulations. Our exploration and production operations outside the United States are subject to various types of regulations similar to those described above imposed by the respective governments of the countries in which we operate, and may affect our operations and costs within that country. We currently have operations in Malaysia, China and the United Kingdom.

Forward-Looking Information

This report contains information that is forward-looking or relates to anticipated future events or results such as planned capital expenditures, the availability of capital resources to fund capital expenditures, estimates of proved reserves and the estimated present value of such reserves, wells planned to be drilled in the future, our financing plans and our business strategy and other plans and objectives for future operations. Although we believe that the expectations reflected in this information are reasonable, this information is based upon assumptions and anticipated results that are subject to numerous uncertainties. Actual results may vary significantly from those anticipated due to many factors, including:

- drilling results;
- oil and gas prices;
- well and waterflood performance;
- severe weather conditions (such as hurricanes);
- the prices of goods and services;

the availability of drilling rigs and other support services;

the availability of capital resources; and

the other factors affecting our business described above under the caption Risk Factors.

All written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by such factors.

Commonly Used Oil and Gas Terms

Below are explanations of some commonly used terms in the oil and gas business.

Basis risk. The risk associated with the sales point price for oil or gas production varying from the reference (or settlement) price for a particular hedging transaction.

Barrel or Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

BLM. The Bureau of Land Management of the United States Department of the Interior.

BOPD. Barrels of oil per day.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Carried interest. An arrangement under which an interest in oil and gas rights is assigned in consideration for the assignee advancing all or a portion of the funds to explore on, develop or operate an oil or gas property.

Completion. The installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Deep shelf. We consider the deep shelf to be structures located on the Shelf at depths generally greater than 14,000 feet in over pressured horizons where there has been limited or no production from deeper stratigraphic zones.

Deepwater. Generally considered to be water depths in excess of 1,000 feet.

Developed acreage. The number of acres that are allocated or assignable to producing wells or wells capable of production.

Development well. A well drilled within the proved area of an oil or natural gas field to the depth of a stratigraphic horizon known to be productive.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploitation well. An exploration well drilled to find and produce probable reserves. Most of the exploitation wells we drilled in 2005 and 2006 and expect to drill in 2007 are located in the Mid-Continent or the Monument Butte Field. Exploitation wells in those areas have less risk and less reserve potential and typically may be drilled at a lower cost than other exploration wells. For internal reporting and budgeting purposes, we combine exploitation and development activities.

Exploration well. A well drilled to find and produce oil or natural gas reserves that is not a development well. For internal reporting and budgeting purposes, we exclude exploitation activities from exploration activities.

Farm-in or farm-out. An agreement whereunder the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a farm-in, while the interest transferred by the assignor is a farm-out.

FERC. The Federal Energy Regulatory Commission.

FPSO. A floating production, storage and off-loading vessel commonly used overseas to produce oil from locations where pipeline infrastructure is not available.

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Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

Gross acres or gross wells. The total acres or wells in which we own a working interest.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

MMS. The Minerals Management Service of the United States Department of the Interior.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMcf. One million cubic feet.

MMcfe. One million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

Net acres or net wells. The sum of the fractional working interests we own in gross acres or gross wells, as the case may be.

NYMEX. The New York Mercantile Exchange.

Probable reserves. Reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Proved developed producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production to market.

Proved developed reserves. In general, proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. The SEC provides a complete definition of proved developed reserves in Rule 4-10(a)(3) of Regulation S-X.

Proved developed nonproducing reserves. Proved developed reserves expected to be recovered from zones behind casing in existing wells.

Proved reserves. In general, the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The SEC provides a complete definition of proved reserves in Rule 4-10(a)(2) of Regulation S-X.

Proved undeveloped reserves. In general, proved 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. The SEC provides a complete definition of proved undeveloped reserves in Rule 4-10(a)(4) of Regulation S-X.

Shelf. The U.S. Outer Continental Shelf of the Gulf of Mexico. Water depths generally range from 50 feet to 1,000 feet.

Tcfe. One trillion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

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Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover. Operations on a producing well to restore or increase production.

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

We are exposed to market risk from changes in oil and gas prices, interest rates and foreign currency exchange rates as discussed below.

Oil and Gas Prices

We generally hedge a substantial, but varying, portion of our anticipated oil and gas production for the next 12-24 months as part of our risk management program. In the case of acquisitions, we may hedge acquired production for a longer period. We use hedging to reduce price volatility, help ensure that we have adequate cash flow to fund our capital programs and manage price risks and returns on some of our acquisitions and drilling programs. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While hedging limits the downside risk of adverse price movements, it may also limit future revenues from favorable price movements. For a further discussion of our hedging activities, see the information under the caption Oil and Gas Hedging in Item 7 of this report and Note 5, Commodity Derivative Instruments and Hedging Activities, to our consolidated financial statements.

Interest Rates

At December 31, 2006, our current and long-term debt was comprised of:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
Bank revolving credit facility	$	$
7.45% Senior Notes due 2007[1][2]	75	50
75/8% Senior Notes due 2011[1]	125	50
65/8% Senior Subordinated Notes due 2014	325	
65/8% Senior Subordinated Notes due 2016	550	
Total current and long-term debt	$ 1,075	$ 100

(1) $50 million principal amount of our 7.45% Senior Notes due 2007 and $50 million principal amount of our 75/8% Senior Notes due 2011 are subject to interest rate swaps. These swaps provide for us to pay variable and receive fixed interest payments, and are designated as fair value hedges of a portion of our outstanding senior notes.

(2) Classified as current debt on our consolidated balance sheet at December 31, 2006.

We consider our interest rate exposure to be minimal because as of December 31, 2006 about 91% of our long-term debt obligations, after taking into account our interest rate swap agreements, were at fixed rates. The impact on annual cash flow of a 10% change in the floating rate applicable to our variable rate debt would be less than $1 million.

Foreign Currency Exchange Rates

The British pound is the functional currency for our operations in the United Kingdom. The functional currency for all other foreign operations is the U.S. dollar. To the extent that business transactions in these countries are not denominated in the respective country s functional currency, we are exposed to foreign currency exchange risk. We consider our current risk exposure to exchange rate movements, based on net cash flows, to be immaterial. We did not have any open derivative contracts relating to foreign currencies at December 31, 2006.

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Item 8. ***Financial Statements and Supplementary Data***

NEWFIELD EXPLORATION COMPANY
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CONSOLIDATED FINANCIAL STATEMENTS
AND SUPPLEMENTARY DATA

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our company s management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our company s management, including the Chief Executive Officer and the Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Our 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 our assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of our financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our 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.

Based on our evaluation under the framework in *Internal Control Integrated Framework,* the management of our company concluded that our internal control over financial reporting was effective as of December 31, 2006.

The assessment by the management of our company of the effectiveness of our internal control over financial reporting as of December 31, 2006 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report that follows.

David A. Trice	Terry W. Rathert
President and Chief Executive Officer	Senior Vice President and Chief Financial Officer

Houston, Texas
March 1, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors of Newfield Exploration Company:

We have completed integrated audits of Newfield Exploration Company s 2006 consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of stockholders equity and of cash flows present fairly, in all material respects, the financial position of Newfield Exploration Company and its subsidiaries (the Company) at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. 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 of these statements 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 of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for stock-based compensation effective January 1, 2006 in conjunction with the Company s adoption of SFAS No. 123(R), *Share-Based Payment.*

Internal control over financial reporting

Also, in our opinion, management s assessment, included in the accompanying Management s Report on Internal Control Over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the COSO. The Company 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 opinions on management s assessment and on the effectiveness of the Company s internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting 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. An audit of internal control over financial reporting includes 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 consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company;

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(ii) 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 (iii) 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.

Houston, Texas
March 1, 2007

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEET
(In millions, except share data)

	December 31, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 80	$ 39
Short-term investments	10	
Accounts receivable	378	370
Inventories	44	22
Derivative assets	280	10
Deferred taxes		46
Other current assets	59	53
Total current assets	851	540
Oil and gas properties (full cost method, of which $1,002 and $901 were excluded from amortization at December 31, 2006 and December 31, 2005, respectively)	8,890	7,042
Less accumulated depreciation, depletion and amortization	(3,235)	(2,632)
	5,655	4,410
Furniture, fixtures and equipment, net	28	20
Derivative assets	19	17
Other assets	20	23
Deferred taxes		9
Goodwill	62	62
Total assets	$ 6,635	$ 5,081
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 59	$ 41
Current debt	124	
Accrued liabilities	667	454
Advances from joint owners	90	29
Asset retirement obligation	40	47
Derivative liabilities	80	99
Deferred taxes	63	
Total current liabilities	1,123	670

Other liabilities	28	21
Derivative liabilities	179	209
Long-term debt	1,048	870
Asset retirement obligation	232	213
Deferred taxes	963	720
Total long-term liabilities	2,450	2,033
Commitments and contingencies (Note 14)		
Stockholders equity:		
Preferred stock ($0.01 par value, 5,000,000 shares authorized; no shares issued)		
Common stock ($0.01 par value, 200,000,000 shares authorized at December 31, 2006 and 2005; 131,063,555 and 129,356,162 shares issued and outstanding at December 31, 2006 and 2005, respectively)	1	1
Additional paid-in capital	1,198	1,186
Treasury stock (at cost, 1,879,874 and 1,815,594 shares at December 31, 2006 and 2005, respectively)	(30)	(27)
Unearned compensation		(34)
Accumulated other comprehensive income (loss):		
Foreign currency translation adjustment	14	(4)
Commodity derivatives	(5)	(40)
Minimum pension liability	(3)	
Retained earnings	1,887	1,296
Total stockholders equity	3,062	2,378
Total liabilities and stockholders equity	$ 6,635	$ 5,081

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF INCOME
(In millions, except per share data)

	Year Ended December 31,		
	2006	2005	2004
Oil and gas revenues	$ 1,673	$ 1,762	$ 1,353
Operating expenses:			
Lease operating	277	205	152
Production and other taxes	61	64	42
Depreciation, depletion and amortization	624	521	472
Ceiling test writedown	6	10	17
General and administrative	124	104	84
Other	(11)	(29)	35
Total operating expenses	1,081	875	802
Income from operations	592	887	551
Other income (expense):			
Interest expense	(87)	(72)	(58)
Capitalized interest	44	46	26
Commodity derivative income (expense)	389	(322)	(24)
Other	11	4	4
	357	(344)	(52)
Income before income taxes	949	543	499
Income tax provision:			
Current	30	70	62
Deferred	328	125	125
	358	195	187
Net income	$ 591	$ 348	$ 312
Earnings per share:			
Basic	$ 4.67	$ 2.78	$ 2.68
Diluted	$ 4.58	$ 2.73	$ 2.63
Weighted average number of shares outstanding for basic earnings per share	127	125	117

Weighted average number of shares outstanding for diluted earnings per share	129	128	119

The accompanying notes to consolidated financial statements are an integral part of this statement.

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NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY
(In millions)

	Common Stock		Treasury Stock		Additional Paid-In	Unearned	Retained	Accumulated Other Comprehensive Income (Loss)	Total Stockholders
	Shares	Amount	Shares	Amount	Capital	Compensation	Earnings		Equity
Balance, December 31, 2003	114.2	$ 1	(1.8)	$ (27)	$ 796	$ (11)	$ 636	$ (26)	$ 1,369
Issuance of common stock	12.2				297				297
Issuance of restricted stock, less amortization and cancellations	0.2				3	(3)			
Amortization of stock compensation						4			4
Tax benefit from exercise of stock options					6				6
Comprehensive income:									
Net income							312		312
Foreign currency translation adjustment, net of tax of ($1)								2	2
Reclassification adjustments for settled hedging positions, net of tax of $31								(57)	(57)
Changes in fair value of outstanding hedging positions, net of tax of ($45)								83	83
Minimum pension liability, net of tax								1	1
Total comprehensive income									341
Balance, December 31, 2004	126.6	1	(1.8)	(27)	1,102	(10)	948	3	2,017
Issuance of common stock	2.1				33				33

Issuance of restricted stock, less amortization and cancellations	0.7				34	(26)			8
Amortization of stock compensation						2			2
Tax benefit from exercise of stock options					17				17
Comprehensive income:									
Net income							348		348
Foreign currency translation adjustment, net of tax of $3								(7)	(7)
Reclassification adjustments for settled hedging positions, net of tax of $60								(110)	(110)
Reclassification adjustments for discontinued cash flow hedges, net of tax of $3								(7)	(7)
Changes in fair value of outstanding hedging positions, net of tax of ($41)								77	77
Total comprehensive income									301
Balance, December 31, 2005	129.4	1	(1.8)	(27)	1,186	(34)	1,296	(44)	2,378
Issuance of common stock	0.7				15				15
Issuance of restricted stock, less amortization and cancellations	1.0				26				26
Amortization of stock compensation					(34)	34			
Treasury stock			(0.1)	(3)					(3)
Stock-based compensation excess tax benefit					5				5
Minimum pension liability, net of tax of $1								(3)	(3)
Comprehensive income:									
Net income							591		591
Foreign currency translation adjustment, net of tax of ($10)								18	18
Reclassification adjustments for settled hedging positions, net of								(29)	(29)

tax of $16																
Changes in fair value of outstanding hedging positions, net of tax of ($35)														64		64
Total comprehensive income																644
Balance, December 31, 2006	131.1	$	1	(1.9)	$	(30)	$	1,198	$		$	1,887	$	6	$	3,062

The accompanying notes to consolidated financial statements are an integral part of this statement.

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NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF CASH FLOWS
(In millions)

	Year Ended December 31, 2006	2005	2004
Cash flows from operating activities:			
Net income	$ 591	$ 348	$ 312
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	624	521	472
Deferred taxes	328	125	125
Stock-based compensation	21	10	4
Commodity derivative (income) expense	(254)	210	
Impairment (gain on sale) of floating production system and pipelines		(7)	35
Ceiling test writedown	6	10	17
Early redemption cost on senior subordinated notes	8		
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	6	(122)	(100)
Increase in inventories	(24)	(15)	(5)
(Increase) decrease in other current assets	(6)	(14)	59
(Increase) decrease in other assets	12	2	(3)
Increase in accounts payable and accrued liabilities	17	41	80
Decrease in commodity derivative liabilities	(13)	(14)	(11)
Increase in advances from joint owners	60	11	12
Increase in other liabilities	8	3	
Net cash provided by operating activities	1,384	1,109	997
Cash flows from investing activities:			
Additions to oil and gas properties	(1,693)	(1,047)	(853)
Purchase of business, net of cash acquired of $2 for 2004			(756)
Proceeds from sale of oil and gas properties	23	11	17
Proceeds from sale of floating production system and pipelines		7	
Insurance recoveries	45		
Additions to furniture, fixtures and equipment	(13)	(7)	(7)
Purchases of short-term investments	(714)		
Redemption of short-term investments	690		
Net cash used in investing activities	(1,662)	(1,036)	(1,599)
Cash flows from financing activities:			
Proceeds from borrowings under credit arrangements	519	868	1,254
Repayments of borrowings under credit arrangements	(519)	(988)	(1,229)

Proceeds from issuances of common stock	15	32	297
Proceeds from issuance of senior subordinated notes	550		325
Repayments of senior subordinated notes	(250)		
Repurchases of secured notes			(3)
Stock-based compensation excess tax benefit	5		
Purchases of treasury stock	(3)		
Net cash provided by (used in) financing activities	317	(88)	644
Effect of exchange rate changes on cash and cash equivalents	2	(4)	1
Increase (decrease) in cash and cash equivalents	41	(19)	43
Cash and cash equivalents, beginning of period	39	58	15
Cash and cash equivalents, end of period	$ 80	$ 39	$ 58

The accompanying notes to consolidated financial statements are an integral part of this statement.

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NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies:

Organization and Principles of Consolidation

We are an independent oil and gas company engaged in the exploration, development and acquisition of crude oil and natural gas properties. Our diversified domestic areas of operation include the Anadarko and Arkoma Basins of the Mid-Continent, the onshore Gulf Coast, the Uinta Basin of the Rocky Mountains and the Gulf of Mexico. Internationally, we are active offshore Malaysia and China and in the U.K. North Sea.

Our financial statements include the accounts of Newfield Exploration Company, a Delaware corporation, and its subsidiaries. We proportionately consolidate our interests in oil and gas exploration and production ventures and partnerships in accordance with industry practice. All significant intercompany balances and transactions have been eliminated. Unless otherwise specified or the context otherwise requires, all references in these notes to Newfield, we, us or our are to Newfield Exploration Company and its subsidiaries.

Common Stock Split

Following the close of trading on May 25, 2005, we completed a two-for-one split of our common stock. The split was effected by a common stock dividend. As a result, the stated par value per share of our common stock was not changed from $0.01. These financial statements and notes have been restated to retroactively reflect the stock split.

Dependence on Oil and Gas Prices

As an independent oil and gas producer, our revenue, profitability and future rate of growth are substantially dependent on prevailing prices for natural gas and oil. The energy markets have historically been very volatile, and there can be no assurance that oil and gas prices will not be subject to wide fluctuations in the future. A substantial or extended decline in oil or gas prices could have a material adverse effect on our financial position, results of operations, cash flows and access to capital and on the quantities of oil and gas reserves that we can economically produce.

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, the reported amounts of revenues and expenses during the reporting period and the reported amounts of proved oil and gas reserves. Actual results could differ from these estimates. Our most significant financial estimates are based on our proved oil and gas reserves.

Reclassifications

Certain reclassifications have been made to prior years reported amounts in order to conform with the current year presentation. These reclassifications did not impact our net income, stockholders equity or cash flows.

Revenue Recognition

Substantially all of our natural gas and oil production is sold to a variety of purchasers under short-term (less than 12 months) contracts at market sensitive prices. We record revenue when we deliver our production to the customer and collectibility is reasonably assured. Revenues from the production of oil and gas on properties in which we have joint ownership are recorded under the sales method. Differences between these sales and our entitled share of production are not significant.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Insurance Recoveries

On August 11, 2006, we reached an agreement with our insurance underwriters to settle all claims related to Hurricanes Katrina and Rita (business interruption, property damage and control of well/operator s extra expense) for $235 million. Based on the nature of the coverage provided under the policies, the settlement proceeds were recorded as follows:

- a cumulative inception to date credit of $58 million to other operating expense for amounts attributable to business interruption coverage;
- a credit of $48 million to our domestic full cost pool for amounts attributable to property damage coverage; and
- a cumulative credit of $129 million to lease operating expense for amounts attributable to all other hurricane repair and cleanup related coverage.

In our consolidated statement of cash flows the cash related to the settlement of the property damage portion of our policies is reflected as a source of investing cash flows and the cash related to the settlement of our business interruption policy and our control of well/operator s extra expense policies is reflected as a source of operating cash flows. All remaining costs expected to be incurred in future periods related to the hurricanes will be accounted for based on the nature of the cost (i.e. capitalized to the extent related to field redevelopment and expensed to the extent related to repair or debris removal).

Cash and Cash Equivalents

Cash and cash equivalents include highly liquid investments with a maturity of three months or less when acquired and are stated at cost, which approximates fair value. We invest cash in excess of near-term capital and operating requirements in U.S. Treasury Notes, Eurodollar time deposits and money market funds which are classified as cash on our consolidated balance sheet.

Allowance for Doubtful Accounts

We routinely assess the recoverability of all material trade and other receivables to determine their collectibility. Many of our receivables are from joint interest owners of properties we operate. Thus, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Generally, our natural gas and crude oil receivables are collected within 45-60 days of production.

We accrue 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 the reserve may be reasonably estimated. As of December 31, 2006 and 2005, our allowance for doubtful accounts was immaterial.

Investments

Investments consist of highly liquid investment grade commercial paper and municipal and corporate bonds with a maturity of less than one year. These investments are classified as available-for-sale. Accordingly, unrealized gains and losses and the related deferred income tax effects are excluded from earnings and reported as a separate component of stockholders equity. Realized gains or losses are computed based on specific identification of the securities sold.

Inventories

Inventories consist primarily of tubular goods and well equipment held for use in our oil and gas operations and oil produced in our operations offshore Malaysia and China but not sold. Inventories are carried at the lower of cost or market. Crude oil from our operations offshore Malaysia and China is produced into

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

floating production, storage and off-loading vessels and sold periodically as barge quantities are accumulated. The product inventory consisted of approximately 176,000 barrels and 36,000 barrels of crude oil valued at cost of $5 million and $0.7 million at December 31, 2006 and 2005, respectively. Cost for purposes of the carrying value of oil inventory is the sum of production costs and depreciation, depletion and amortization expense.

Foreign Currency

The British pound is the functional currency for our operations in the United Kingdom. Translation adjustments resulting from translating our United Kingdom subsidiaries British pound financial statements into U.S. dollars are included as accumulated other comprehensive income on our consolidated balance sheet and statement of stockholders equity. The functional currency for all other foreign operations is the U.S. dollar. Gains and losses incurred on currency transactions in other than a country s functional currency are recorded under the caption Other income (expense) Other on our consolidated statement of income.

Oil and Gas Properties

We use the full cost method of accounting for our oil and gas producing activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties, including salaries, benefits and other internal costs directly attributable to these activities, are capitalized into cost centers that are established on a country-by-country basis. We capitalized $58 million, $46 million and $32 million of internal costs in 2006, 2005 and 2004, respectively. Interest expense related to unproved properties also is capitalized into oil and gas properties.

Capitalized costs and estimated future development and retirement costs are amortized on a unit-of-production method based on proved reserves associated with the applicable cost center. For each cost center, the net capitalized costs of oil and gas properties are limited to the lower of the unamortized cost or the cost center ceiling. A particular cost center ceiling is equal to the sum of:

- the present value (10% per annum discount rate) of estimated future net revenues from proved reserves using end of period oil and gas prices applicable to our reserves (including the effects of hedging contracts that are designated for hedge accounting); plus

- the lower of cost or estimated fair value of properties not included in the costs being amortized, if any; less

- related income tax effects.

Proceeds from the sale of oil and gas properties are applied to reduce the costs in the applicable cost center unless the sale involves a significant quantity of reserves in relation to the cost center, in which case a gain or loss is recognized.

If net capitalized costs of oil and gas properties exceed the cost center ceiling, we are subject to a ceiling test writedown to the extent of such excess. If required, a ceiling test writedown would reduce earnings and stockholders equity in the period of occurrence and result in lower depreciation, depletion and amortization expense in future periods.

The risk that we will be required to writedown the carrying value of our oil and gas properties increases when oil and gas prices decrease significantly or if we have substantial downward revisions in our estimated proved reserves. At December 31, 2006, the ceiling value of our reserves was calculated based upon quoted market prices of $5.64 per MMBtu for gas and $61.05 per barrel for oil, adjusted for market differentials. Using these prices, the unamortized net capitalized costs of our domestic oil and gas properties would have exceeded the ceiling amount by approximately $5 million (net of tax of $3 million) at December 31, 2006. Cash flow hedges of oil production in place at December 31, 2006 decreased the calculated ceiling value by

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

approximately $5 million (net of tax of $3 million). However, on February 22, 2007, the market price for gas (Gas Daily Henry Hub) increased to $7.48 per MMBtu and the market price for oil (Platt s WTI at Cushing) decreased to $60.95 per barrel. Utilizing these prices, the unamortized costs of our oil and gas properties would not have exceeded the ceiling amount at December 31, 2006. As a result, we did not record a writedown in the fourth quarter of 2006. The ceiling value calculated using the February 22, 2007 prices includes approximately $5 million (net of tax of $3 million) related to the negative effects of cash flow hedges of oil production.

In September 2006, we decided to cease our exploration efforts in Brazil. As a result, we recognized a ceiling test writedown of $6 million for our Brazil cost center in the third quarter of 2006.

In December 2005, we decided to decrease our emphasis on exploration efforts in Brazil and to no longer pursue opportunities in several other countries. As a result, we recognized a ceiling test writedown of $10 million in the fourth quarter of 2005. In November 2004, we announced that our Cumbria Prospect in the U.K. North Sea was a dry hole. Because the unamortized costs of our U.K. cost pool at that time exceeded the full cost ceiling, we recognized a ceiling test writedown of $17 million in 2004.

Furniture, Fixtures and Equipment

Furniture, fixtures and equipment are recorded at cost and are depreciated using the straight-line method over their estimated useful lives, which range from three to seven years. At December 31, 2006 and 2005, furniture, fixtures and equipment of $53 million and $39 million, respectively, are presented net of accumulated depreciation of $25 million and $19 million, respectively.

Asset Retirement Obligations

If a reasonable estimate of the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells can be made, we record a liability (an asset retirement obligation or ARO) on our consolidated balance sheet and capitalize the asset retirement cost in oil and gas properties in the period in which the retirement obligation is incurred. In general, the amount of an ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation assuming the normal operation of the asset, using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an assumed cost of funds for our company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds and the additional capitalized costs are depreciated on a unit-of-production basis within the related full cost pool. Both the accretion and the depreciation are included in depreciation, depletion and amortization on our consolidated statement of income.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The change in our ARO for the three years ended December 31, 2006 is set forth below (in millions):

Balance at January 1, 2004	$ 164
Accretion expense	11
Additions	48
Settlements	(6)
Balance at December 31, 2004	217
Accretion expense	13
Additions	10
Revisions[(1)]	34
Settlements	(14)
Balance at December 31, 2005	260
Accretion expense	14
Additions	19
Revisions	(2)
Settlements	(19)
Balance of ARO at December 31, 2006	$ 272

(1) Reflects an increase in the abandonment estimate of Gulf of Mexico platforms and facilities that were damaged or destroyed by Hurricanes Katrina and Rita.

Goodwill

We recorded goodwill in connection with our acquisitions of Inland Resources (August 2004) and a company holding Mid-Continent oil and gas properties (2003). Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of the liabilities assumed. In the third quarter of 2005, the goodwill associated with Inland Resources was adjusted to reflect the recognition of an additional $3 million in tax assets.

We assess the carrying amount of goodwill by testing the goodwill for impairment. The impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. We have deemed each country to be a goodwill reporting unit. The fair value of each reporting unit is determined and compared to the book value of that reporting unit. If the fair value of the reporting unit is less than its book value (including goodwill) then goodwill is reduced to its implied fair value and the amount of the writedown is charged to earnings. Goodwill is tested for impairment on an annual basis on December 31, or more frequently if an event occurs or circumstances change that have an adverse effect on the fair value of the reporting unit such that the fair value could be less than the book value of such unit.

The fair value of a reporting unit is based on our estimates of future net cash flows from proved reserves and from future exploration for and development of unproved reserves. Downward revisions of estimated reserves or production, increases in estimated future costs or decreases in oil and gas prices could lead to an impairment of all or a portion of goodwill in future periods.

We have not impaired any goodwill.

Income Taxes

We use the liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are determined by applying tax regulations existing at the end of a reporting period to the cumulative

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

temporary differences between the tax bases of assets and liabilities and their reported amounts in our financial statements. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

In July 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes, an interpretation of SFAS No. 109, Accounting for Income Taxes. FIN 48 prescribes a comprehensive model for how companies should recognize, measure, present and disclose in their financial statements uncertain tax positions taken or expected to be taken on a tax return. Under FIN 48, tax positions are recognized in our consolidated financial statements as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement with tax authorities assuming full knowledge of the position and all relevant facts. These amounts are subsequently reevaluated and changes are recognized as adjustments to current period tax expense. FIN 48 also revises disclosure requirements to include an annual tabular rollforward of unrecognized tax benefits. We are required to adopt FIN 48 on January 1, 2007. Upon adoption, we will be required to apply the provisions of FIN 48 to all tax positions and any cumulative effect adjustment will be recognized as an adjustment to retained earnings. We have completed our initial evaluation of the impact of FIN 48 and determined that its adoption is not expected to have a material impact on our financial position or results of operations.

Stock-Based Compensation

On January 1, 2006, we adopted SFAS No. 123 (revised 2004), *Share-Based Payment*, (SFAS No. 123(R)) to account for stock-based compensation. Among other items, SFAS No. 123(R) eliminates the use of APB 25 and the intrinsic value method of accounting and requires companies to recognize in their financial statements the cost of services received in exchange for awards of equity instruments based on the grant date fair value of those awards. We elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, has been or will be recognized in our financial statements over the remaining vesting period. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense, based on the fair value on the date of grant or modification, has been or will be recognized in our financial statements over the vesting period. We utilize the Black-Scholes option pricing model to measure the fair value of stock options and a lattice-based model for our performance and market-based restricted shares. Prior to the adoption of SFAS No. 123(R), we followed the intrinsic value method in accordance with APB 25 to account for stock-based compensation. Prior period financial statements have not been restated. See Note 11, Stock-Based Compensation, for a full discussion of our stock-based compensation.

Concentration of Credit Risk

We operate a substantial portion of our oil and gas properties. As the operator of a property, we make full payment for costs associated with the property and seek reimbursement from the other working interest owners in the property for their share of those costs. Our joint interest partners consist primarily of independent oil and gas producers. If the oil and gas exploration and production industry in general was adversely affected, the ability of our joint interest partners to reimburse us could be adversely affected.

The purchasers of our oil and gas production consist primarily of independent marketers, major oil and gas companies, refiners and gas pipeline companies. We perform credit evaluations of the purchasers of our production and monitor their financial condition on an ongoing basis. Based on our evaluations and monitoring, we obtain cash escrows, letters of credit or parental guarantees from some purchasers. Historically, we have sold a substantial portion of our oil and gas production to several purchasers (see *Major Customers* below). We have not experienced any significant losses from uncollectible accounts.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

All of our hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions involves the risk that the counterparties may be unable to meet the financial terms of the transactions. The counterparties for all of our hedging transactions have an investment grade credit rating. We monitor on an ongoing basis the credit ratings of our hedging counterparties. At December 31, 2006, Bank of Montreal, JPMorgan Chase Bank, Citibank, N.A. and J Aron & Company were the counterparties with respect to 73% of our future hedged production.

Major Customers

For the years ended December 31, 2006, 2005 and 2004, we sold oil and gas production that accounted for more than 10% of our consolidated revenues (before the effects of hedging) to Superior Natural Gas Corporation (18% in 2006, 23% in 2005 and 20% in 2004), Louis Dreyfus Energy Services (less than 10% in 2006, 12% in 2005 and 15% in 2004) and ConocoPhillips Inc. (less than 10% in 2006 and 2005 and 14% in 2004). We believe that the loss of any of these purchasers would not have a material adverse effect on us because alternative purchasers of this production are readily available.

Derivative Financial Instruments

We account for our derivative activities under the provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS Nos. 137, 138 and 149. The statement, as amended, establishes accounting and reporting standards requiring that every derivative instrument be recorded on the balance sheet as either an asset or a liability measured at its fair value. The statement requires that changes in the derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Substantially all of the derivative instruments that we utilize are to manage the price risk attributable to our expected oil and gas production. We also have utilized derivatives to manage our exposure associated with interest rates (see Note 8, Debt *Interest Rate Swaps*).

Historically, we applied hedge accounting to derivatives utilized to manage price risk associated with our oil and gas production. Accordingly, we recorded changes in the fair value of our collar and floor contracts (other than contracts that are part of three-way collar contracts), including changes associated with time value, under the caption Accumulated other comprehensive income (loss) Commodity derivatives on our consolidated balance sheet. Gains or losses on these collar and floor contracts are reclassified out of Accumulated other comprehensive income (loss) Commodity derivatives and into oil and gas revenues when the forecasted sale of production occurs.

Any hedge ineffectiveness associated with contracts qualifying for and designated as a cash flow hedge (which represents the amount by which the change in the fair value of the derivative differs from the change in the cash flows of the forecasted sale of production) is reported currently each period under the caption Commodity derivative income (expense) on our consolidated statement of income.

Some of our derivatives (three-way collar contracts) do not qualify for hedge accounting but are effective as economic hedges of our commodity price exposure. These contracts are accounted for using the mark-to-market accounting method. Under this method, the contracts are carried at their fair value on our consolidated balance sheet under the captions Derivative assets and Derivative liabilities. We recognize all unrealized and realized gains and losses related to these contracts on our consolidated statement of income under the caption Commodity derivative income (expense).

Beginning with the fourth quarter of 2005, we elected not to designate any future price risk management activities as accounting hedges under SFAS No. 133, and accordingly, account for them using the mark-to-market accounting method described above. We continue to account for previously designated and qualifying derivatives as cash flow hedges.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The related cash flow impact of all of our derivative activities are reflected as cash flows from operating activities. See Note 5, Commodity Derivative Instruments and Hedging Activities, for a full discussion of our hedging activities.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net earnings (loss) as well as unrealized gains and losses on derivative instruments and cumulative foreign currency translation adjustments, all recorded net of tax.

2. Earnings Per Share:

Basic earnings per share (EPS) is calculated by dividing net income (the numerator) by the weighted average number of shares of common stock (other than unvested restricted stock) outstanding during the period (the denominator). Diluted earnings per share incorporates the dilutive impact of outstanding stock options and unvested restricted shares (using the treasury stock method). See Note 11, Stock-Based Compensation.

The following is the calculation of basic and diluted weighted average shares outstanding and EPS for each of the years in the three-year period ended December 31, 2006:

	2006	2005	2004
	(In millions, except per share data)		
Income (numerator):			
Net income basic and diluted	$ 591	$ 348	$ 312
Weighted average shares (denominator):			
Weighted average shares basic	127	125	117
Dilution effect of stock options and unvested restricted shares outstanding at end of period	2	3	2
Weighted average shares diluted	129	128	119
Earnings per share:			
Basic	$ 4.67	$ 2.78	$ 2.68
Diluted	$ 4.58	$ 2.73	$ 2.63

The calculation of shares outstanding for diluted EPS for the years ended December 31, 2006, 2005 and 2004 does not include the effect of 137 thousand, 69 thousand and 728 thousand outstanding stock options and unvested restricted shares, respectively, because to do so would be antidilutive.

3. Acquisitions:

Malaysian PSCs

Over the past several years, we have entered into several production sharing contracts, or PSCs, with Malaysia s state-owned oil company relating to blocks offshore Malaysia and Sarawak.

In May 2004, we entered into several PSCs that relate to two blocks PM 318 and deepwater Block 2C. Petronas Carigali, a state-owned, Malaysian exploration and production company, operates PM 318, which consists of approximately 414,000 acres, located offshore Peninsular Malaysia. We have a 50% interest in the block. The consideration for our interests in PM 318 was comprised of a one-time reimbursement of sunk costs of $39 million and a deferred payment of $11 million. Block 2C covers 1.1 million acres in deepwater offshore Sarawak. In November 2006, we farmed out 20% of our interest in Block 2C. Block 2C is operated by us with a 40% interest. We have committed to future exploration on these two blocks.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In June 2005, we entered into a PSC with respect to PM 323. We operate the block with a 60% interest. The PSC covers approximately 320,000 acres in the Malay Basin and is located approximately 40 miles from PM 318. The consideration for our interest was comprised of a deferred payment of $8 million and a future development and exploration commitment.

See Note 14, Commitments and Contingencies *Other Commitments*.

Oklahoma Assets

During the second half of 2004, we acquired producing oil and gas properties in Oklahoma in two separate transactions for total cash consideration of approximately $58 million. These acquisitions were financed through cash on hand and borrowings under our credit arrangements.

Denbury Offshore, Inc.

On July 20, 2004, we acquired all of the outstanding stock of Denbury Offshore, Inc., the subsidiary of Denbury Resources Inc. that held substantially all of its Gulf of Mexico assets. We accounted for the acquisition as a purchase using the accounting standards established in SFAS No. 141, Business Combinations. Our consolidated financial statements include Denbury Offshore s results of operations subsequent to July 20, 2004. After purchase price adjustments, total consideration was approximately $174 million, substantially all of which was allocated to oil and gas properties. The acquisition was financed through cash on hand and borrowings under our credit arrangements.

Inland Resources Inc.

On August 27, 2004, we completed the $575 million acquisition of privately held Inland Resources Inc. Inland s sole oil and gas property was the 100,000 acre Monument Butte Field, located in the Uinta Basin of northeast Utah. The purchase price was funded through concurrent offerings of our common stock and our 65/8% Senior Subordinated Notes due 2014. See Note 8, Debt, and Note 9, Common Stock Activity.

We accounted for the acquisition as a purchase using the accounting standards established in SFAS Nos. 141 and 142. Our consolidated financial statements include Inland s results of operations subsequent to August 27, 2004. We recorded the estimated fair value of the assets acquired and the liabilities assumed at August 27, 2004, which primarily consisted of oil and gas properties of $723 million, a deferred tax liability of $171 million, derivative liabilities of $31 million and goodwill of $49 million. We recorded the deferred tax liability to recognize the difference between the historical tax basis of Inland s net assets and the acquisition costs recorded for accounting purposes. Inland s historical book value of the proved and unproved oil and gas properties was increased to estimated fair value and goodwill was recorded to recognize this tax basis differential. In the third quarter of 2005, goodwill was reduced to reflect the recognition of an additional $3 million tax asset related to the acquisition. Goodwill is not deductible for tax purposes. See Note 1, Organization and Summary of Significant Accounting Policies *Goodwill.*

Pro Forma Results

The unaudited pro forma results presented below for the year ended December 31, 2004 have been prepared to give effect to our 2004 acquisitions and the issuance of our common stock and notes as described above on our results of operations under the purchase method of accounting as if they had been consummated on January 1, 2004. The unaudited pro forma results do not purport to represent what our results of operations actually would have been if these acquisitions had in fact occurred on such date or to project our results of operations for any future date or period.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31, 2004 (Unaudited) (In millions, except per share)
Pro forma:	
Revenue	$ 1,457
Income from operations	589
Net income	344
Basic earnings per share	$ 2.79
Diluted earnings per share	$ 2.75

4. Oil and Gas Assets:

Oil and Gas Properties

Oil and gas properties consisted of the following at:

	December 31, 2006	December 31, 2005 (In millions)	December 31, 2004
Subject to amortization	$ 7,888	$ 6,141	$ 5,073
Not subject to amortization:			
Exploration in progress	182	147	91
Development in progress	49	16	7
Capitalized interest	94	71	39
Fee mineral interests	23	23	23
Other capital costs:			
Incurred in 2006	102		
Incurred in 2005	92	110	
Incurred in 2004	378	413	479
Incurred in 2003 and prior	82	121	196
Total not subject to amortization	1,002	901	835
Gross oil and gas properties	8,890	7,042	5,908
Accumulated depreciation, depletion and amortization	(3,235)	(2,632)	(2,133)
Net oil and gas properties	$ 5,655	$ 4,410	$ 3,775

A portion of incurred (if not previously included in the amortization base) and future development costs associated with qualifying major development projects may be temporarily excluded from amortization. To qualify, a project must require significant costs to ascertain the quantities of proved reserves attributable to the properties under development (e.g., the installation of an offshore production platform from which development wells are to be drilled). Incurred and future costs are allocated between completed and future work. Any temporarily excluded costs are included in the amortization base upon the earlier of when the associated reserves are determined to be proved or impairment is indicated. As of December 31, 2006 and 2005, we excluded from the amortization base $26 million (which is included in costs not subject to amortization in the table above) associated with our deepwater Gulf of Mexico project known as Glider, located at Green Canyon 247/248.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We believe that substantially all of the properties associated with costs not currently subject to amortization will be evaluated within four years except the Monument Butte Field. Because of its size (100,000 acres), evaluation of the Monument Butte Field in its entirety will take significantly longer than four years. At December 31, 2006, 2005 and 2004, $292 million, $316 million and $341 million, respectively, of costs associated with the Monument Butte Field were not subject to amortization.

Malaysia Block 2C

During the fourth quarter of 2006, we sold a 20% interest in Block 2C in deepwater offshore Sarawak. The sales proceeds of $4 million have been recorded as an adjustment to our Malaysia cost center.

U.K. Southern Gas Basin Sale Agreement

In September 2006, we sold a 15% interest in our Grove Field and recorded sales proceeds of $17 million as an adjustment to our U.K. cost center. As part of the sale, the purchaser agreed to participate in the ongoing development of our Grove Field and our 2007 exploration and appraisal drilling program.

Floating Production System and Pipelines

As a result of our acquisition of EEX Corporation in November 2002, we owned a 60% interest in a floating production system, some offshore pipelines and a processing facility located at the end of the pipelines in shallow water. At the time of acquisition, we estimated the fair value of these assets to be $35 million.

From their acquisition, we undertook to sell these assets. In December 2004, when what we believed was the last commercial opportunity for sale was not realized, we determined that there was no active market for these assets. As a result, in connection with the preparation of our financial statements for the year ended December 31, 2004, we recorded a $35 million impairment charge under the caption Operating expenses Other on our consolidated statement of income. In August 2005, we sold our interest in the floating production facility and related equipment for net proceeds of $7 million, which were recorded as a gain under the caption Operating expenses Other on our consolidated statement of income.

5. Commodity Derivative Instruments and Hedging Activities:

We utilize swap, floor, collar and three-way collar derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future oil and gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, their use also may limit future revenues from favorable price movements.

With respect to a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price for such contract, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price for such contract. For a floor contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price for such contract. We are not required to make any payment in connection with the settlement of a floor contract. For a collar contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price for such contract, we are required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price for such contract and neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract. A three-way collar contract consists of a standard collar contract plus a put sold by us with a price below the floor price of the collar. This additional put requires us to make a payment to the counterparty if the settlement price for any settlement period is below the put price. Combining the collar contract with the additional put results in us being entitled to a net payment equal to the difference

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

between the floor price of the standard collar and the additional put price if the settlement price is equal to or less than the additional put price. If the settlement price is greater than the additional put price, the result is the same as it would have been with a standard collar contract only. This strategy enables us to increase the floor and the ceiling price of the collar beyond the range of a traditional no cost collar while defraying the associated cost with the sale of the additional put.

Substantially all of our oil and gas derivative contracts are settled based upon reported prices on the NYMEX. The estimated fair value of these contracts is based upon various factors, including closing exchange prices on the NYMEX, over-the-counter quotations, volatility and, in the case of collars and floors, the time value of options. The calculation of the fair value of collars and floors requires the use of an option-pricing model.

Cash Flow Hedges

Prior to the fourth quarter of 2005, all derivatives that qualified for hedge accounting were designated on the date we entered into the contract as a hedge of the variability in cash flows associated with the forecasted sale of our future oil and gas production. After-tax changes in the fair value of a derivative that is highly effective and is designated and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded under the caption Accumulated other comprehensive income (loss) Commodity derivatives on our consolidated balance sheet until the sale of the hedged oil and gas production. Upon the sale of the hedged production, the net after-tax change in the fair value of the associated derivative recorded under the caption Accumulated other comprehensive income (loss) Commodity derivatives is reversed and the gain or loss on the hedge, to the extent that it is effective, is reported in Oil and gas revenues on our consolidated statement of income. At December 31, 2006, we had a net $5 million after-tax loss recorded under the caption Accumulated other comprehensive income (loss) Commodity derivatives. We expect hedged production associated with commodity derivatives accounting for such net loss to be sold within the next 12 months. The actual gain or loss on these commodity derivatives could vary significantly as a result of changes in market conditions and other factors.

For those contracts designated as a cash flow hedge, we formally document all relationships between the derivative instruments and the hedged production, as well as our risk management objective and strategy for the particular derivative contracts. This process includes linking all derivatives that are designated as cash flow hedges to the specific forecasted sale of oil or gas at its physical location. We also formally assess (both at the derivative s inception and on an ongoing basis) whether the derivatives being utilized have been highly effective at offsetting changes in the cash flows of hedged production and whether those derivatives may be expected to remain highly effective in future periods. If it is determined that a derivative has ceased to be highly effective as a hedge, we will discontinue hedge accounting prospectively. If hedge accounting is discontinued and the derivative remains outstanding, we will carry the derivative at its fair value on our consolidated balance sheet and recognize all subsequent changes in its fair value on our consolidated statement of income for the period in which the change occurs.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At December 31, 2006, we had outstanding contracts that qualify and were designated as cash flow hedges with respect to our future production as follows:

Oil

		NYMEX Contract Price per Bbl					Estimated Fair Value Asset
			Collars				
		Swaps	Floors		Ceilings		
Period and Type of Contract	Volume in MBbls	(Weighted Average)	Range	Weighted Average	Range	Weighted Average	(Liability) (In millions)
January 2007 March 2007							
Price swap contracts	210	$ 41.68					$ (4)
Collar contracts	90		$ 50.00 - $55.00	$ 52.50	$ 77.10 -$83.25	$ 80.18	
April 2007 June 2007							
Price swap contracts	211	41.77					(5)
Collar contracts	91		50.00 - 55.00	52.50	77.10 -83.25	80.18	
July 2007 September 2007							
Price swap contracts	92	61.25					
Collar contracts	92		50.00 - 55.00	52.50	77.10 -83.25	80.18	
October 2007 December 2007							
Price swap contracts	92	61.25					
Collar contracts	92		50.00 - 55.00	52.50	77.10 -83.25	80.18	
							$ (9)

Other Derivative Contracts

Beginning in the fourth quarter of 2005, we elected not to designate any additional swap, collar and floor contracts that were entered into subsequent to September 30, 2005 as accounting hedges under SFAS No. 133. These contracts, as well as our three-way contracts that do not qualify as cash flow hedges, are carried at their fair value on our consolidated balance sheet under the captions Derivative assets and Derivative liabilities. We recognize all unrealized and realized gains and losses related to these contracts on our consolidated statement of income under the caption Commodity derivative income (expense). Settlements of such derivative contracts are included in operating cash flows on our consolidated statement of cash flows.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At December 31, 2006, we had outstanding contracts with respect to our future production that are not accounted for as hedges as set forth in the tables below.

Natural Gas

		NYMEX Contract Price per MMBtu					Estimated Fair Value Asset
			Collars				
		Swaps	Floors		Ceilings		
Period and Type of Contract	**Volume in MMBtus**	**(Weighted Average)**	**Range**	**Weighted Average**	**Range**	**Weighted Average**	**(Liability) (In millions)**
January 2007 March 2007							
Price swap contracts	9,730	$ 9.86					$ 34
Collar contracts	29,640		$ 9.00 - $10.00	$ 9.24	$ 11.00 -$15.75	$ 13.15	87
April 2007 June 2007							
Price swap contracts	23,980	8.90					52
Collar contracts	19,100		6.50 - 8.00	6.90	8.23 -10.15	8.81	13
July 2007 September 2007							
Price swap contracts	24,270	8.92					45
Collar contracts	15,350		6.50 - 8.00	6.86	8.23 -10.15	8.80	6
October 2007 December 2007							
Price swap contracts	9,890	8.98					15
Collar contracts	11,460		6.50 - 8.00	7.53	8.23 -12.40	10.39	5
January 2008 December 2008							
Price swap contracts	8,080	8.40					3
Collar contracts	13,520		7.00 - 8.00	7.76	9.70 -12.40	11.04	1
							$ 261

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Oil

			NYMEX Contract Price per Bbl					
					Collars			
		Swaps	Additional Put		Floors		Ceilings	
	Volume in	(Weighted		Weighted		Weighted		Weighte
Type of Contract	MBbls	Average)	Range	Average	Range	Average	Range	Averag
7 March 2007								
ontracts	30	$ 70.00						
cts	60				$60.00	$ 60.00	$ 80.50 - $81.00	$ 80.7
contracts	870		$ 25.00 - $50.00	$ 30.03	32.00 - 60.00	37.14	44.70 - 82.00	55.3
June 2007								
ontracts	30	70.00						
cts	60				60.00	60.00	80.50 - 81.00	80.7
contracts	879		25.00 - 50.00	30.02	32.00 -60.00	37.12	44.70 - 82.00	55.3
September 2007								
ontracts	30	70.00						
cts	60				60.00	60.00	80.50 - 81.00	80.7
contracts	888		25.00 - 50.00	30.00	32.00 -60.00	37.10	44.70 - 82.00	55.3
7 December 2007								
ontracts	30	70.00						
cts	60				60.00	60.00	80.50 - 81.00	80.7
contracts	888		25.00 - 50.00	30.00	32.00 -60.00	37.10	44.70 - 82.00	55.3
3 December 2008								
contracts	3,294		25.00 - 29.00	26.56	32.00 -35.00	33.00	49.50 - 52.90	50.2
) December 2009								
contracts	3,285		25.00 - 30.00	27.00	32.00 -36.00	33.33	50.00 - 54.55	50.6
) December 2010								
contracts	3,645		25.00 - 32.00	28.60	32.00 -38.00	34.90	50.00 - 53.50	51.5

Commodity Derivative Income (Expense). The following table presents information about the components of commodity derivative income (expense) for each of the years in the three-year period ended December 31, 2006.

	Year Ended December 31,		
	2006	2005	2004

	(In millions)		
Cash flow hedges:			
Hedge ineffectiveness	$ 5	$ (8)	$ 4
Other derivative contracts:			
Realized loss on settlement of discontinued cash flow hedges		(51)	
Unrealized gain (loss) due to changes in fair market value	249	(202)	(4)
Realized gain (loss) on settlement	135	(61)	(24)
Total commodity derivative income (expense)	$ 389	$ (322)	$ (24)

Hedge ineffectiveness is associated with our hedging contracts that qualify for hedge accounting under SFAS No. 133. As a result of the production deferrals experienced in the Gulf of Mexico related to Hurricanes Katrina and Rita, hedge accounting was discontinued during the third quarter of 2005 on a portion of our derivative contracts that had previously qualified as effective cash flow hedges of our Gulf of Mexico

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

production and other contracts were redesignated as hedges of our onshore Gulf Coast production. As a result, realized losses of $51 million associated with derivative contracts for the third and fourth quarters of 2005, which were in excess of hedged physical deliveries for those periods, were reported as commodity derivative expense. The unrealized gain (loss) due to changes in fair market value is associated with our derivative contracts that are not designated for hedge accounting and represents changes in the fair value of these open contracts during the period.

6. Accrued Liabilities:

As of the indicated dates, our accrued liabilities consisted of the following:

	December 31, 2006	December 31, 2005
	(In millions)	
Revenue payable	$ 95	$ 117
Accrued capital costs	349	154
Accrued lease operating expenses	58	33
Employee incentive expense	63	60
Accrued interest on notes	21	21
Taxes payable	21	26
Deferred acquisition payments	9	20
Insurance premium payable	16	4
Other	35	19
Total accrued liabilities	$ 667	$ 454

7. Accounts Receivable:

As of the indicated dates, our accounts receivable consisted of the following:

	December 31, 2006	December 31, 2005
	(In millions)	
Revenue	$ 201	$ 287
Joint interest	148	52
Business interruption insurance		21
Receivable from broker	14	
MMS deposits	8	9
Texas severance tax	6	
Other	1	1

Total accounts receivable	$	378	$	370

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Debt:

As of the indicated dates, our debt consisted of the following:

	December 31, 2006	December 31, 2005
	(In millions)	
Senior unsecured debt:		
Bank revolving credit facility:		
Prime rate based loans	$	$
LIBOR based loans		
Total bank revolving credit facility		
7.45% Senior Notes due 2007[1]	125	125
Fair value of interest rate swaps[2]	(1)	(2)
75/8% Senior Notes due 2011	175	175
Fair value of interest rate swaps[2]	(2)	(2)
Total senior unsecured notes	297	296
Total senior unsecured debt	297	296
83/8% Senior Subordinated Notes due 2012		249
65/8% Senior Subordinated Notes due 2014	325	325
65/8% Senior Subordinated Notes due 2016	550	
Total debt	1,172	870
Less: Current portion of debt[1]	124	
Total long-term debt	$ 1,048	$ 870

(1) Due October 2007.

(2) See *Interest Rate Swaps* below.

Credit Arrangements

In December 2005, we entered into a revolving credit facility that matures in December 2010. The terms of the credit facility provide for initial loan commitments of $1 billion from a syndication of banks, led by JPMorgan Chase as the agent bank. The loan commitments under the credit facility may be increased to a maximum aggregate amount of $1.5 billion if the lenders increase their loan commitments or new financial institutions are added to the credit facility. Loans under the credit facility bear interest, at our option, based on (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank or the weighted average of the rates on overnight federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 50 basis points or (b) a base Eurodollar rate substantially equal to the London Interbank Offered Rate, plus a margin that is based on a grid of our debt rating (100 basis points per annum at December 31, 2006). At December 31, 2006 and 2005, we had no borrowings under the credit facility.

Under our new credit facility and our previous credit facilities, we pay or paid commitment fees on the undrawn amounts based on a grid of our debt rating (0.20% per annum at December 31, 2006). We paid fees under these arrangements of approximately $2 million for the years ended December 31, 2006 and 2005 and $1 million for the year ended December 31, 2004.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The credit facility has restrictive covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed 0.6 to 1.0; maintenance of a ratio of total debt to earnings before gain or loss on the disposition of assets, interest expense, income taxes, depreciation, depletion and amortization expense, exploration and abandonment expense and other noncash charges and expenses to consolidated interest expense of at least 3.5 to 1.0; and, as long as our debt rating is below investment grade, the maintenance of an annual ratio of the calculated net present value of our oil and gas properties to total debt of at least 1.75 to 1.00. At December 31, 2006, we were in compliance with all of our debt covenants.

As of December 31, 2006, we had $52 million of undrawn letters of credit under our credit facility. The letters of credit outstanding under the credit facility are subject to annual fees, based on a grid of our debt rating (87.5 basis points at December 31, 2006), plus an issuance fee of 12.5 basis points.

We also have a total of $100 million of borrowing capacity under money market lines of credit with various banks. At December 31, 2006 and 2005, we had no borrowings under our money market lines.

Senior Notes

On October 15, 1997, we issued $125 million aggregate principal amount of our 7.45% Senior Notes due 2007. The estimated fair value of these notes at December 31, 2006 and 2005 was $126 million and $128 million, respectively, based on quoted market prices on those dates.

On February 22, 2001, we issued $175 million aggregate principal amount of our 75/8% Senior Notes due 2011. The estimated fair value of these notes at December 31, 2006 and 2005 was $183 million and $188 million, respectively, based on quoted market prices on those dates.

Interest on our senior notes is payable semi-annually. Our senior notes are unsecured and unsubordinated obligations and rank equally with all of our other existing and future unsecured and unsubordinated obligations.

We may redeem some or all of our senior notes at any time before their maturity at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. The indentures governing our senior notes contain covenants that may limit our ability to, among other things:

- incur debt secured by certain liens;
- enter into sale/leaseback transactions; and
- enter into merger or consolidation transactions.

The indentures also provide that if any of our subsidiaries guarantee any of our indebtedness at any time in the future, then we will cause our senior notes to be equally and ratably guaranteed by that subsidiary.

Senior Subordinated Notes

On August 13, 2002, we issued $250 million aggregate principal amount of our 83/8% Senior Subordinated Notes due 2012. On May 3, 2006, we redeemed all $250 million principal amount of these notes. The redemption included a premium related to the early extinguishment of the notes of $19 million. This premium and the remaining unamortized original issuance costs of the notes of $8 million were recorded as an expense under the caption Operating expenses Other on our consolidated statement of income.

On August 12, 2004, we issued $325 million aggregate principal amount of our 65/8% Senior Subordinated Notes due 2014. The net proceeds of $323 million were used together with the net proceeds of our concurrent stock offering (see Note 9, Common Stock Activity) to fund the acquisition of Inland (see Note 3, Acquisitions). The estimated fair value of these notes at December 31, 2006 and 2005 was $323 million and $332 million, respectively, based on quoted market prices on those dates.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On April 13, 2006, we issued $550 million aggregate principal amount of our 65/8% Senior Subordinated Notes due 2016. The net proceeds from the offering (approximately $545 million) were used to redeem our 83/8% Senior Subordinated Notes due 2012 ($250 million aggregate principal amount and associated redemption premium as discussed above) and for general corporate purposes, which included funding a portion of our 2006 capital program. The estimated fair value of these notes at December 31, 2006 was $546 million based on quoted market prices on that date.

Interest on our senior subordinated notes is payable semi-annually. The notes are unsecured senior subordinated obligations that rank junior in right of payment to all of our present and future senior indebtedness.

We may redeem some or all of our 65/8% notes due 2014 at any time on or after September 1, 2009 and some or all of our 65/8% notes due 2016 at any time on or after April 15, 2011, in each case, at a redemption price stated in the applicable indenture governing the notes. We may also redeem all but not part of our 65/8% notes due 2014 prior to September 1, 2009 and all but not part of our 65/8% notes due 2016 prior to April 15, 2011, in each case, at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. In addition, before September 1, 2007, we may redeem up to 35% of the original principal amount of our 65/8% notes due 2014 with the net cash proceeds from certain sales of our common stock at 106.625% of the principal amount plus accrued and unpaid interest to the date of redemption. Likewise, before April 15, 2009, we may redeem up to 35% of the original principal amount of our 65/8% notes due 2016 with similar net cash proceeds at 106.625% of the principal amount plus accrued and unpaid interest to the date of redemption.

The indenture governing our senior subordinated notes limits our ability to, among other things:

- incur additional debt;
- make restricted payments;
- pay dividends on or redeem our capital stock;
- make certain investments;
- create liens;
- make certain dispositions of assets;
- engage in transactions with affiliates; and
- engage in mergers, consolidations and certain sales of assets.

Secured Notes

In connection with our acquisition of EEX Corporation in November 2002, we assumed $101 million principal amount of secured notes. The notes accrued interest at a rate of 7.54% per year and were secured by the floating production system and pipelines described in Note 4, Oil and Gas Assets *Floating Production System and Pipelines*.

Prior to 2004, we repaid or repurchased all but $3 million principal amount of the notes. In January 2004, we repurchased the remaining notes.

Interest Rate Swaps

During September 2003, we entered into interest rate swap agreements to take advantage of low interest rates and to obtain what we viewed as a more desirable proportion of variable and fixed rate debt. We hedged $50 million principal amount of our 7.45% Senior Notes due 2007 and $50 million principal amount of our 75/8% Senior Notes due 2011. These swap agreements provide for us to pay variable and receive fixed interest payments and are designated as fair value hedges of a portion of our outstanding senior notes.

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NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Pursuant to SFAS No. 133, changes in the fair value of derivatives designated as fair value hedges are recognized as offsets to the changes in fair value of the exposure being hedged. As a result, the fair value of our interest rate swap agreements is reflected within our derivative assets or liabilities on our consolidated balance sheet and changes in their fair value are recorded as an adjustment to the carrying value of the associated long-term debt. Receipts and payments related to our interest rate swaps are reflected in interest expense.

9. Common Stock Activity:

Following the close of trading on May 25, 2005, we completed a two-for-one split of our common stock. The split was effected by a common stock dividend.

On August 12, 2004, we issued 5.4 million shares (10.8 million post split) of our common stock at $52.85 per share ($26.43 post split). The net proceeds of $277 million were used in conjunction with the net proceeds of our concurrent Senior Subordinated Notes offering (see Note 8, Debt *Senior Subordinated Notes*) to acquire Inland (see Note 3, Acquisitions *Inland Resources Inc.*).

10. Income Taxes:

Income before income taxes consists of the following:

	For the Year Ended December 31,		
	2006	**2005**	**2004**
		(In millions)	
U.S.	$ 941	$ 515	$ 496
Foreign	8	28	3
Total income before income taxes	$ 949	$ 543	$ 499

The total provision for income taxes consists of the following:

	For the Year Ended December 31,		
	2006	**2005**	**2004**
		(In millions)	
Current taxes:			
U.S. federal	$ 31	$ 54	$ 53
U.S. state	1	1	1
Foreign	(2)	15	8

Deferred taxes:			
U.S. federal	298	121	118
U.S. state	12	11	7
Foreign	18	(7)	
Total provision for income taxes	$ 358	$ 195	$ 187

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The provision for income taxes for each of the years in the three-year period ended December 31, 2006 was different than the amount computed using the federal statutory rate (35%) for the following reasons:

	For the Year Ended December 31,		
	2006	2005	2004
	(In millions)		
Amount computed using the statutory rate	$ 332	$ 190	$ 175
Increase (decrease) in taxes resulting from:			
State and local income taxes, net of federal effect	8	8	5
Net effect of different tax rates in non-U.S. jurisdictions	(3)	1	(1)
Tax credits and other	3	1	
Valuation allowance	18	(5)	8
Total provision for income taxes	$ 358	$ 195	$ 187

The components of our deferred tax asset and deferred tax liability are as follows:

	December 31, 2006			December 31, 2005		
	U.S.	Foreign	Total	U.S.	Foreign	Total
	(In millions)					
Deferred tax asset:						
Net operating loss carryforwards	$ 156	$ 21	$ 177	$ 112	$ 14	$ 126
Alternative minimum tax credit	46		46			
Commodity derivatives	55		55	75		75
Other, net	30		30	(35)		(35)
Valuation allowance		(21)	(21)		(3)	(3)
Deferred tax asset	287		287	152	11	163
Deferred tax liability:						
Commodity derivatives	(74)		(74)			
Oil and gas properties	(1,231)	(8)	(1,239)	(826)	(2)	(828)
Deferred tax liability	(1,305)	(8)	(1,313)	(826)	(2)	(828)
Net deferred tax asset (liability)	(1,018)	(8)	(1,026)	(674)	9	(665)
Less net current deferred tax asset (liability)	(63)		(63)	46		46

Noncurrent deferred tax asset (liability)	$	(955)	$	(8)	$	(963)	$	(720)	$	9	$	(711)

As of December 31, 2006, we had net operating loss (NOL) carryforwards for federal and state income tax purposes of approximately $388 million and $532 million, respectively, that may be used in future years to offset taxable income. As of December 31, 2006, we had NOL carryforwards for international income tax purposes of approximately $48 million that may be used in future years to offset taxable income. We currently estimate that we will not be able to utilize these international NOLs, therefore a valuation allowance was established for them. Utilization of the NOL carryforwards is subject to annual limitations due to certain stock ownership changes. To the extent not utilized, the NOL carryforwards will begin to expire during the years 2012 through 2024. Utilization of NOL carryforwards is dependent upon generating sufficient taxable income in the appropriate jurisdictions within the carryforward period. Estimates of future taxable income can be significantly affected by changes in natural gas and oil prices, estimates of the timing and amount of future production and estimates of future operating and capital costs.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The rollforward of our deferred tax asset valuation allowance is as follows:

	For Year Ended December 31,		
	2006	2005	2004
	(In millions)		
Balance at the beginning of the year	$ (3)	$ (8)	$
Credited (charged) to provision for income taxes:			
United Kingdom NOL carryforwards	(15)	8	(8)
Brazil and Other International NOL carryforwards	(3)	(3)	
Balance at the end of the year	$ (21)	$ (3)	$ (8)

U.S. deferred taxes have not been provided on foreign income of $39 million that is permanently reinvested internationally. We currently do not have any foreign tax credits available to reduce U.S. taxes on this income if it was repatriated.

11. Stock-Based Compensation:

On January 1, 2006, we adopted SFAS No. 123(R) to account for stock-based compensation. Among other things, SFAS No. 123(R) eliminates the use of APB 25 and the intrinsic value method of accounting and requires companies to recognize in their financial statements the cost of services received in exchange for awards of equity instruments based on the grant date fair value of those awards. We elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date or modification date, has been or will be recognized in our financial statements over the remaining vesting period. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense, based on the fair value on the date of grant, has been or will be recognized in our financial statements over the vesting period. We utilize the Black-Scholes option pricing model to measure the fair value of stock options and a lattice-based model for our performance and market-based restricted shares. Prior to the adoption of SFAS No. 123(R), we followed the intrinsic value method in accordance with APB 25 to account for stock-based compensation. Prior period financial statements have not been restated.

Historically, we have used and we anticipate continuing to use unissued shares of stock when stock options are exercised. At December 31, 2006, we had approximately 2.6 million additional shares available for issuance pursuant to our existing employee and director plans. Of the shares available at December 31, 2006, only 1.2 million could be granted as restricted shares. Grants of restricted shares under our 2004 Omnibus Stock Plan reduce the total number of shares available under that plan by two times the number of restricted shares issued.

The modified prospective method requires us to estimate forfeitures in calculating the expense related to stock-based compensation as opposed to our prior policy of recognizing the forfeitures as they occurred. We recorded a cumulative effect gain on a change in accounting principle of $1 million as a result of the adoption of this standard. Because the amount was immaterial, we included it in general and administrative expense on our consolidated statement of income.

The modified prospective method precludes changes to the grant date fair value of equity awards granted before the required effective date of adoption of SFAS No. 123(R). Any unearned compensation recorded under APB 25 related to these awards is eliminated against the appropriate equity accounts. As a result, upon adoption we eliminated $34 million of unearned compensation cost and reduced by a like amount additional paid-in capital on our consolidated balance sheet.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2006, we recorded stock-based compensation expense of $32 million (pre-tax) for all plans. Of that amount, $11 million was capitalized in oil and gas properties. Our net income was reduced by $5 million, or $0.04 per basic and diluted share, as a result of the adoption of SFAS No. 123(R). SFAS No. 123(R) also requires that tax benefits relating to stock-based compensation deductions in excess of the deferred tax assets recorded at the time of grant be prospectively presented in our statement of cash flows as a source of financing cash flows. Accordingly, for the year ended December 31, 2006, we reported $5 million of excess tax benefits from stock-based compensation as cash provided by financing activities on our statement of cash flows.

As of December 31, 2006, we had approximately $60 million of total unrecognized compensation expense related to unvested stock-based compensation plans. This compensation expense is expected to be recognized on a straight-line basis over the remaining vesting period of approximately 5 years.

Stock Options. We have granted stock options under several plans. Options generally expire ten years from the date of grant and become exercisable at the rate of 20% per year. The exercise price of options cannot be less than the fair market value per share of our common stock on the date of grant.

The fair value of the stock options granted prior to and remaining outstanding at January 1, 2006 was determined using the Black-Scholes option valuation method assuming no dividends, a weighted average risk-free interest rate of 4.09%, an expected life of 6.5 years and a weighted average volatility of 37.52%.

The following table provides information related to stock option activity for the year ended December 31, 2006:

	Number of Shares Underlying Options (In millions)	Weighted Average Exercise Price per Share	Weighted Average Grant Date Fair Value per Share	Weighted Average Remaining Contractual Life (In years)	Aggregate Intrinsic Value[1] (In millions)
Outstanding at December 31, 2005	6.5	$ 23.60	$ 10.66	7.4	$ 171
Granted					
Exercised	(0.6)	20.91	9.31		(15)
Forfeited	(0.3)	27.50	12.54		(6)
Outstanding at December 31, 2006	5.6	23.68	10.71	6.3	124
Exercisable at December 31, 2006	2.7	$ 19.58	$ 8.83	5.2	$ 71

(1) The intrinsic value of a stock option is the amount by which the current market value of the underlying stock at the indicated date, grant date, exercise date or forfeiture date, as applicable, exceeds the exercise price of the option.

The aggregate intrinsic value of stock options exercised during 2005 was approximately $49 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes information about stock options outstanding and exercisable at December 31, 2006:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Shares Underlying Options (In thousands)	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price per Share	Number of Shares Underlying Options (In thousands)	Weighted Average Exercise Price per Share
$ 7.97 to $10.00	44	1.6 years	$ 8.14	44	$ 8.14
10.01 to 12.50	115	1.2 years	11.78	115	11.78
12.51 to 15.00	476	3.1 years	14.72	471	14.71
15.01 to 17.50	1,151	5.5 years	16.63	733	16.63
17.51 to 22.50	869	5.3 years	18.96	641	18.96
22.51 to 27.50	898	7.2 years	24.73	285	24.65
27.51 to 35.00	1,641	8.0 years	31.13	338	30.84
35.01 to 41.72	377	8.0 years	37.91	53	38.30
	5,571	6.3 years	$ 23.68	2,680	$ 19.58

Common stock issued upon the exercise of non-qualified stock options during 2004 and 2005 resulted in a tax deduction for us equivalent to the compensation income recognized by the option holder and is recognized as a credit to additional paid in capital rather than as a reduction of income tax expense. For 2006, only the excess tax benefit is recognized as a credit to additional paid in capital and is calculated as the amount by which the tax deduction we receive exceeds the deferred tax asset associated with recorded stock compensation expense. The amounts credited to additional paid in capital for 2006, 2005 and 2004 were approximately $5 million, $17 million and $6 million, respectively.

Restricted Shares. At December 31, 2006, our employees held 0.6 million restricted shares that primarily vest equally over the service period of five years. The vesting of these shares is dependant upon the employees continued service with our company.

In addition, at December 31, 2006, our employees held 1.5 million restricted shares subject to performance-based vesting criteria (substantially all of which are considered market-based restricted shares under SFAS No. 123(R)). In February 2006, 974,000 of these restricted performance-based shares were granted. The number of these shares that vest is based upon established performance targets that will be assessed on March 1, 2009. The grant date fair value of these shares was $23.20 per share for a total value of $23 million. The expense will be recognized ratably over the service period from February 2006 to March 2009. Under the grants to our executive officers, they are permitted to retire on or after March 1, 2008, if certain other conditions are met, without forfeiting the shares granted. To the extent that our executive officers qualify for retirement based on this provision, the expense will be recognized ratably over the service period from February 2006 to the applicable retirement eligibility date. Substantially all of the remaining performance based shares may vest in whole or in part in 2008, 2009 or 2010. The percentage of the shares vesting, if any, in a year is subject to the achievement of the targets identified in the respective restricted share agreements.

Under our non-employee director restricted stock plan as in effect on December 31, 2006, immediately after each annual meeting of our stockholders, each of our non-employee directors then in office received a number of restricted shares determined by dividing $75,000 by the fair market value of one share of our common stock on the date of the annual meeting. In addition, new directors elected after an annual meeting receive a number of restricted shares determined by dividing $75,000 by the fair market value of one share of our common stock on the date of their election. The forfeiture restrictions lapse on the day before the first

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

annual meeting of stockholders following the date of issuance of the shares if the holder remains a director until that time. At December 31, 2006, 109,913 shares remained available for grants under this plan.

The following table provides information related to restricted share activity for the year ended December 31, 2006:

	Service-Based	Performance/ Market-Based	Total
	(In thousands, except per share data)		
Non-vested shares outstanding at December 31, 2005	710	640	1,350
Granted	224	974	1,198
Forfeited	(67)	(96)	(163)
Vested	(218)	(2)	(220)
Non-vested shares outstanding at December 31, 2006	649	1,516	2,165
Weighted average grant date fair value per share of shares granted during the period	$ 43.50	$ 23.20	$ 27.23
Total fair value of shares vested during the period	$ 3,759	$ 49	$ 3,808

Employee Stock Purchase Plan. Pursuant to our employee stock purchase plan, for each six month period beginning on January 1 or July 1 during the term of the plan, each eligible employee has the opportunity to purchase our common stock for a purchase price equal to 85% of the lesser of the fair market value of our common stock on the first day of the period or the last day of the period. No employee may purchase common stock under the plan valued at more than $25,000 in any calendar year. Employees of our foreign subsidiaries are not eligible to participate in the plan.

During 2006, options to purchase 51,445 shares of our common stock at a weighted average fair value of $13.35 per share were issued under the plan. The fair value of the options granted in 2006 was determined using the Black-Scholes option valuation method assuming no dividends, a risk-free weighted-average interest rate of 4.83%, an expected life of 6 months and weighted-average volatility of 40.04%. At December 31, 2006, 658,614 shares of our common stock remained available for issuance pursuant to the plan.

U.K. Bonus Plan. We have a cash bonus plan for the employees of our U.K. North Sea operations. The value of the bonus is determined based on the value of the shares of our U.K. subsidiary as determined by our Board of Directors. This plan is accounted for as a liability plan under SFAS No. 123(R) and is not material to our financial statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Pro forma Disclosures. Prior to January 1, 2006, we accounted for our employee stock-based compensation using the intrinsic value method prescribed by APB 25. As required by SFAS No. 123(R), we have disclosed below the effect on net income and earnings per share that would have been recorded using the fair value based method for the years 2005 and 2004. The weighted average fair value of the options granted during 2005 was determined using the Black-Scholes option valuation method assuming no dividends, a weighted average risk-free interest rate of 3.76%, an expected life of 6.5 years and weighted average volatility of 38.13%. The weighted average fair value of the options granted during 2004 was determined using the Black-Scholes option valuation method assuming no dividends, a weighted average risk-free interest rate of 3.25%, an expected life of 6.5 years and weighted average volatility of 40.94%.

	Year Ended December 31, 2005	Year Ended December 31, 2004
	(In millions, except per share data)	
Net income:		
As reported[(1)]	$ 348	$ 312
Pro forma[(2)]	339	305
Basic earnings per common share		
As reported	$ 2.78	$ 2.68
Pro forma	2.70	2.61
Diluted earnings per common share		
As reported	$ 2.73	$ 2.63
Pro forma	2.65	2.57

(1) Includes stock-based compensation costs, net of related tax effects, of $7 million and $3 million for the years ended December 31, 2005 and 2004.

(2) Includes stock-based compensation costs, net of related tax effects, that would have been included in the determination of net income had the fair value based method been applied of $16 million and $10 million for the years ended December 31, 2005 and 2004, respectively.

12. Pension Plan Obligation:

As a result of our acquisition of EEX in November 2002, we assumed responsibility for a defined pension benefit plan for current and former employees of EEX and its subsidiaries. The plan was amended, effective March 31, 2003, to cease all future retirement benefit accruals. After March 31, 2003, no participant has earned any further benefit accruals under the plan participant benefits were frozen as of March 31, 2003 and the benefits will not increase based upon future service completed or compensation received after that date. Accrued pension costs are funded based upon applicable requirements of federal law and deductibility for federal income tax purposes.

In September 2006, SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans was issued. SFAS No. 158 requires, among other things, the recognition of the funded status of each defined pension benefit plan, retiree health care and other post-retirement benefit plans and post-employment benefit plans on the balance sheet. Each overfunded plan is recognized as an asset and each underfunded plan is recognized as a liability. The initial impact of adoption of the standard due to unrecognized prior service costs or credits and net actuarial gains or losses as well as subsequent changes in the funded status is recognized as a component of accumulated comprehensive income in stockholders equity. Minimum pension liabilities and related intangible assets also are derecognized upon adoption. SFAS No. 158 requires initial application for fiscal years ending after December 15, 2006. We adopted SFAS No. 158 as of

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December 31, 2006 and recorded a charge of $2 million (net of tax of $1 million) to accumulated other comprehensive loss with a corresponding $3 million increase in accrued pension liability.

The following tables summarize changes in the benefit obligation, the plan assets and the funded status of our pension plan as well as the components of net periodic benefit costs, including key assumptions. The measurement dates for plan assets and obligations were December 31, 2006 and 2005.

	2006	2005
	(In millions)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$ (30)	$ (27)
Interest cost	(2)	(2)
Benefits paid	1	1
Actuarial loss	(3)	(2)
Benefit obligation at end of year	$ (34)	$ (30)
Change in plan assets:		
Fair value of plan assets at beginning of year	$ 23	$ 22
Actual return on plan assets	3	1
Employer contributions	2	1
Benefits paid	(1)	(1)
Fair value of plan assets at end of year	$ 27	$ 23
Minimum liability recognition:		
Accumulated benefit obligation (ABO)	$ (34)	$ (30)
Fair value of plan assets	27	23
Unfunded ABO	(7)	$ (7)
Accrued pension liability (*before* minimum liability recognition)	4	
Additional liability	$ (3)	

Reconciliation of funded status:

Projected benefit obligation (PBO)	$ (34)	$ (30)
Fair value of plan assets	27	23
Underfunded status	(7)	(7)
Unrecognized net loss	3	
Accrued pension liability (*before* minimum liability recognition)	(4)	$ (7)
Transition adjustment required to recognize minimum liability:		
Accumulated other comprehensive loss	(3)	
Accrued pension liability (*after* minimum liability recognition)	$ (7)	

Check on reconciliation of accrued pension cost:

Accrued pension liability at beginning of year	$ (7)	$ (7)
Company contributions	2	1
Change in accumulated other comprehensive loss	(2)	(1)
Accrued pension liability at end of year	$ (7)	$ (7)

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Net periodic benefit cost:	**Year Ended December 31, 2006**	**2005**	**2004**
	(In millions)		
Interest cost	$ 2	$ 2	$ 2
Expected return on plan assets	(2)	(2)	
Total periodic benefit cost	$	$	$ 2
Key Assumptions for Expense Purposes:			
Discount rate assumption	5.75%	6.00%	6.00%
Expected return on plan assets	8.00%	8.00%	8.00%
Key Assumptions for Disclosure Purposes:			
Discount rate assumption	5.75%	5.75%	6.00%
Expected return on plan assets	8.00%	8.00%	8.00%

In developing the overall expected long-term rate of return on assets, we used a building block approach in which rates of return in excess of inflation were considered separately for equity securities, debt securities and all other assets. The excess returns were weighted by the representative target allocation and added along with an approximate rate of inflation to develop the overall expected long-term rate of return.

We have developed an investment policy to invest in a broad range of securities. The diversified portfolio aims to maximize investment return without exposure to risk levels above those determined by us. The investment policy takes into consideration the retirement plan s benefit obligations including the expected timing of benefit payments.

The following table sets forth the allocation of the plan s assets by category at December 31, 2006 and 2005 as well as the target allocation of assets for 2007.

	Target Allocation 2007	**Percentage of Plan Assets at December 31 2006**	**2005**
Plan Asset Categories:			
Equity securities	40-60%	44%	51%
Debt securities	40-60%	56%	48%
Other	0-10%		1%
Total		100%	100%

The estimated future benefit payments under the plan for the next ten years are as follows (in millions):

<u>Year ending December 31</u>,	
2007	$ 1
2008	1
2009	1
2010	1
2011	1
2012 2016	9

During 2007, we anticipate making a contribution of approximately $1 million to the plan.

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NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Employee Benefit Plans:

Post-Retirement Medical Plan

We sponsor a post-retirement medical plan that covers all retired employees until they reach 65. At December 31, 2006, our accumulated benefit obligation was $4 million and our accrued benefit cost was $3 million. Our net periodic benefit cost has been approximately $1 million per year.

The expected future benefit payments under our post-retirement medical plan for the next ten years are as follows (in millions):

2007 2011	$ 1
Next 5 years	2

Incentive Compensation Plan

Effective January 1, 2003, our Board of Directors adopted our 2003 incentive compensation plan. The plan provides for the creation each calendar year of an award pool that is generally equal to 5% of our adjusted net income (as defined in the plan) plus the revenues attributable to overriding royalty interests bearing on the interests of investors that participate in certain of our activities. Adjusted net income for purposes of this plan excludes unrealized gains and losses on commodity derivatives. The plan is administered by the Compensation & Management Development Committee of our Board of Directors and award amounts are recommended by our chief executive officer. All employees are eligible for awards if employed on both October 1 and December 31 of the performance period. Awards under the plan may, and generally do, have both a current and a deferred component. Deferred awards are paid in four annual installments, each installment consisting of 25% of the deferred award, plus interest. Total expense under the plan for the years ended December 31, 2006, 2005 and 2004 was $39 million, $42 million and $29 million, respectively.

401(k) and Deferred Compensation Plans

We sponsor a 401(k) profit sharing plan under Section 401(k) of the Internal Revenue Code. This plan covers all of our employees other than employees of our foreign subsidiaries. We match $1.00 for each $1.00 of employee deferral, with our contribution not to exceed 8% of an employee s salary, subject to limitations imposed by the Internal Revenue Service. During 1997, we implemented a highly compensated employee deferred compensation plan. This non-qualified plan allows an eligible employee to defer a portion of his or her salary or bonus on an annual basis. We match $1.00 for each $1.00 of employee deferral, with our contribution not to exceed 8% of an employee s salary, subject to limitations imposed by the plan. Our contribution with respect to each participant in the deferred compensation plan is reduced by the amount of contribution made by us to our 401(k) plan for that participant. Our combined contributions to these two plans totaled $4 million, $3 million and $2 million for the years ended December 31, 2006, 2005 and 2004, respectively.

14. Commitments and Contingencies:

Lease Commitments

We have various commitments under non-cancellable operating lease agreements for office space, equipment and drilling rigs. The majority of these commitments are related to multi-year contracts for drilling

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

rigs. Future minimum payments required under our operating leases as of December 31, 2006 are as follows (in millions):

Year Ending December 31,	
2007	$ 80
2008	65
2009	22
2010	4
Thereafter	19
Total minimum lease payments	$ 190

Rent expense with respect to our lease commitments for office space for the years ended December 31, 2006, 2005 and 2004 was $4 million, $5 million and $4 million, respectively.

Other Commitments

As is common in the oil and gas industry, we have various contractual commitments pertaining to exploration, development and production activities. We have work related commitments for, among other things, drilling wells, obtaining and processing seismic data and fulfilling other cash commitments. At December 31, 2006, these work related commitments total $257 million and are comprised of $160 million in the United States and $97 million internationally.

Litigation

We have been named as a defendant in a number of lawsuits arising in the ordinary course of our business. While the outcome of these lawsuits cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

15. Stockholder Rights Plan:

In 1999, we adopted a stockholder rights plan. The plan is designed to ensure that all of our stockholders receive fair and equal treatment if a takeover of our company is proposed. It includes safeguards against partial or two-tiered tender offers, squeeze-out mergers and other abusive takeover tactics.

The plan provides for the issuance of one right for each outstanding share of our common stock. The rights will become exercisable only if a person or group acquires 20% or more of our outstanding voting stock or announces a tender or exchange offer that would result in ownership of 20% or more of our voting stock.

Each right will entitle the holder to buy one one-thousandth (1/1000) of a share of a new series of junior participating preferred stock at an exercise price of $85 per right, subject to antidilution adjustments. Each one one-thousandth of a share of this new preferred stock has the dividend and voting rights of, and is designed to be substantially equivalent to, one share of our common stock. Our Board of Directors may, at its option, redeem all rights for $0.01 per right at any time prior to the acquisition of 20% or more of our outstanding voting stock by a person or group.

If a person or group acquires 20% or more of our outstanding voting stock, each right will entitle holders, other than the acquiring party or parties, to purchase shares of our common stock having a market value of $170 for a purchase price of $85, subject to antidilution adjustments.

The plan also includes an exchange option. If a person or group acquires 20% or more, but less than 50%, of our outstanding voting stock, our Board of Directors may, at its option, exchange the rights in whole or part for shares of our common stock. Under this option, we would issue one share of our common stock, or

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

one one-thousandth of a share of new preferred stock, for each two shares of our common stock for which a right is then exercisable. This exchange would not apply to rights held by the person or group holding 20% or more of our voting stock.

If, after the rights have become exercisable, we merge or otherwise combine with another entity, or sell assets constituting more than 50% of our assets or producing more than 50% of our earnings power or cash flow, each right then outstanding will entitle its holder to purchase for $85, subject to antidilution adjustments, a number of the acquiring party s common shares having a market value of twice that amount.

The plan will not prevent, nor is it intended to prevent, a takeover of our company. Since the rights may be redeemed by our Board of Directors under certain circumstances, they should not interfere with any merger or other business combination approved by our Board. The rights do not in any way diminish our financial strength, affect reported earnings per share or interfere with our business plans.

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NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

16. Segment Information:

While we only have operations in the oil and gas exploration and production industry, we are organizationally structured along geographic operating segments. Our operating segments are the United States, the United Kingdom, Malaysia, China and Other International. The accounting policies of each of our operating segments are the same as those described in Note 1, Organization and Summary of Significant Accounting Policies.

The following tables provide the geographic operating segment information required by SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information* as well as results of operations of oil and gas producing activities required by SFAS No. 69, *Disclosures about Oil and Gas Producing Activities* as of and for the years ended December 31, 2006, 2005, and 2004. Income tax allocations have been determined based on statutory rates in the applicable geographic segment.

	United States	United Kingdom	Malaysia	China	Other International	Total
			(In millions)			
Year Ended December 31, 2006:						
Oil and gas revenues	$ 1,611	$	$ 49	$ 13	$	$ 1,673
Operating expenses:						
Lease operating	261	1	14	1		277
Production and other taxes	49		11	1		61
Depreciation, depletion and amortization	611		9	4		624
Ceiling test writedown					6	6
General and administrative	116	6	1	1		124
Other	(11)					(11)
Allocated income taxes	211		5	2		
Net income (loss) from oil and gas properties	$ 374	$ (7)	$ 9	$ 4	$ (6)	
Total operating expenses						1,081
Income from operations						592
Interest expense, net of interest income, capitalized interest and other						(32)
Commodity derivative income						389
Income before income taxes						$ 949
Total long-lived assets	$ 5,208	$ 200	$ 182	$ 65	$	$ 5,655
Additions to long-lived assets	$ 1,621	$ 151	$ 109	$ 24	$ 1	$ 1,906

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NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	United Kingdom	Malaysia	China	Other International	Total
			(In millions)			
Year Ended December 31, 2005:						
Oil and gas revenues	$ 1,689	$ 1	$ 72	$	$	$ 1,762
Operating expenses:						
Lease operating	190		15			205
Production and other taxes	58		6			64
Depreciation, depletion and amortization	510	1	10			521
Ceiling test writedown					10	10
General and administrative	101	1	1		1	104
Other	(29)					(29)
Allocated income taxes	301		15		(1)	
Net income (loss) from oil and gas properties	$ 558	$ (1)	$ 25	$	$ (10)	
Total operating expenses						875
Income from operations						887
Interest expense, net of interest income, capitalized interest and other						(22)
Commodity derivative expense						(322)
Income before income taxes						$ 543
Total long-lived assets	$ 4,226	$ 46	$ 87	$ 45	$ 6	$ 4,410
Additions to long-lived assets	$ 1,076	$ 35	$ 41	$ 8	$ 3	$ 1,163

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	United Kingdom	Malaysia	China	Other International	Total
			(In millions)			
Year Ended December 31, 2004:						
Oil and gas revenues	$ 1,311	$ 3	$ 39	$	$	$ 1,353
Operating expenses:						
Lease operating	143	1	8			152
Production and other taxes	40		2			42
Depreciation, depletion and amortization	463	2	7			472
Ceiling test writedown		17				17
General and administrative	82	2				84
Other	35					35
Allocated income taxes	192	(1)	8			
Net income (loss) from oil and gas properties	$ 356	$ (18)	$ 14	$	$	
Total operating expenses						802
Income from operations						551
Interest expense, net of interest income, capitalized interest and other						(28)
Commodity derivative expense						(24)
Income before income taxes						$ 499
Total long-lived assets	$ 3,643	$ 26	$ 57	$ 37	$ 12	$ 3,775
Additions to long-lived assets	$ 1,743	$ 32	$ 63	$ 2	$ 5	$ 1,845

17. Supplemental Cash Flow Information:

	Year Ended December 31, 2006	2005	2004
		(In millions)	
Cash payments:			
Interest payments, net of interest capitalized of $44, $46 and $26 during 2006, 2005 and 2004, respectively	$ 39	$ 25	$ 22
Income tax payments	11	54	17
Non-cash items excluded from the statement of cash flows:			

Accrued capital expenditures	$ (142)	$ (66)	$ (33)
Asset retirement costs	(14)	(44)	(48)

18. Related Party Transaction:

David A. Trice, our Chairman, President and Chief Executive Officer, and Susan G. Riggs, our Treasurer, are minority owners of Huffco International L.L.C. In May 1997, prior to Mr. Trice and Ms. Riggs joining us, we acquired from Huffco an entity now known as Newfield China, LDC, the owner of a 12% interest in a three field unit located on Blocks 04/36 and 05/36 in Bohai Bay, offshore China. Huffco retained preferred shares of Newfield China that provide for an aggregate dividend equal to 10% of the excess of proceeds received by Newfield China from the sale of oil, gas and other minerals over all costs incurred with respect to exploration and production in Block 05/36, plus the cash purchase price we paid Huffco for Newfield China ($6 million). At

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2006, Newfield China had approximately $55 million of unrecovered exploration and production costs. As a result, no dividends have been paid to date on its preferred shares. Newfield anticipates that it will begin paying preferred dividends in the third quarter of 2007. Based on our estimate of the net present value of the proved reserves associated with Block 05/36, the indirect interests (through Huffco) in Newfield China s preferred shares held by Mr. Trice and Ms. Riggs had a net present value of approximately $274,000 and $105,000, respectively, at December 31, 2006.

19. Quarterly Results of Operations (Unaudited):

The results of operations by quarter for the years ended December 31, 2006 and 2005 are as follows:

	2006 Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share data)			
Oil and gas revenues	$ 431	$ 390	$ 425	$ 427
Income from operations(1)	232	111	184	65
Net income	149	94	266	82
Basic earnings per common share(2)	$ 1.18	$ 0.74	$ 2.10	$ 0.65
Diluted earnings per common share(2)	$ 1.17	$ 0.73	$ 2.06	$ 0.64

	2005 Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share data)			
Oil and gas revenues	$ 413	$ 446	$ 460	$ 443
Income from operations(3)	197	216	243	231
Net income (loss)	60	104		184
Basic earnings per common share(2)	$ 0.48	$ 0.83	$	$ 1.46
Diluted earnings per common share(2)	$ 0.47	$ 0.82	$	$ 1.43

(1) Income from operations for the second quarter of 2006 includes an early redemption premium of $19 million paid to holders of our 8 3/8% Senior Subordinated Notes due 2012 that were redeemed in May 2006 and the write-off of the remaining unamortized original issuance cost of these notes of $8 million.

Income from operations in the third quarter of 2006 includes a $34 million credit to lease operating expense resulting from the difference between the proceeds received in the third quarter of 2006 from the settlement of all of our insurance claims related to Hurricanes Katrina and Rita and our actual hurricane related expenses incurred to date.

Income from operations in the fourth quarter of 2006 includes $50 million of hurricane related repair expenses incurred subsequent to the settlement of all of our insurance claims related to Hurricanes Katrina and Rita and a $15 million charge related to a valuation allowance on U.K. net operating loss carryforwards.

(2) The sum of the individual quarterly earnings per share may not agree with year-to-date earnings per share as each quarterly computation is based on the income or loss for that quarter and the weighted average number of shares outstanding during that quarter.

(3) Income from operations for the third quarter of 2005 includes an unrealized loss on discontinued cash flow hedges of $65 million as a result of production deferrals experienced in the Gulf of Mexico related to Hurricanes Katrina and Rita. Income from operations for the fourth quarter of 2005 includes a full cost ceiling test writedown of $10 million related to certain of our nonproducing international operations and the recognition of a $22 million benefit related to our business interruption insurance coverage.

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SUPPLEMENTARY FINANCIAL INFORMATION
SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED

Costs incurred for oil and gas property acquisitions, exploration and development for each of the years in the three-year period ended December 31, 2006 are as follows:

	United States	United Kingdom	Malaysia	China	Other International	Total
			(In millions)			
2006:						
Property acquisitions:						
Unproved	$ 62	$ 3	$ 8	$	$	$ 73
Proved	8		7			15
Exploration(1)	1,384	91	48	16	1	1,540
Development(2)	167	57	46	8		278
Total costs incurred(3)	$ 1,621	$ 151	$ 109	$ 24	$ 1	$ 1,906
2005:						
Property acquisitions:						
Unproved	$ 56	$ 3	$ 15	$ 1	$ 1	$ 76
Proved	26					26
Exploration(1)	805	27	23	2	2	859
Development(2)	189	5	3	5		202
Total costs incurred(3)	$ 1,076	$ 35	$ 41	$ 8	$ 3	$ 1,163
2004:						
Property acquisitions:(4)						
Unproved	$ 422	$ 7	$ 7	$ 1	$ 1	$ 438
Proved	560		44			604
Exploration(1)	618	25	9	1	4	657
Development(2)	143		3			146
Total costs incurred(3)(4)	$ 1,743	$ 32	$ 63	$ 2	$ 5	$ 1,845

(1) Includes $359 million, $254 million and $136 million of United States costs for non-exploitation activities for 2006, 2005 and 2004, respectively; $7 million, $26 million and $25 million of United Kingdom costs for non-exploitation activities for 2006, 2005 and 2004, respectively; $22 million, $17 million and $9 million of Malaysia costs for non-exploitation activities for 2006, 2005 and 2004, respectively; $1 million, $1 million and $1 million of China costs for non-exploitation activities for 2006, 2005 and 2004, respectively; and $1 million, $2 million and $4 million of Other International costs for non-exploitation activities for 2006, 2005 and 2004, respectively.

(2) Includes $16 million, $44 million and $48 million for 2006, 2005 and 2004, respectively, of asset retirement costs recorded in accordance with SFAS No. 143.

(3) Totals for each year exclude the following:

	2006	2005 (In millions)	2004
Property sales proceeds	$ 23	$ 10	$ 17
Foreign currency translation adjustment	(19)	6	(2)
Ceiling test writedown international	6	10	17
Insurance settlement proceeds domestic	48		
	$ 58	$ 26	$ 32

(4) Includes $344 million and $375 million recorded as unproved and proved property acquisition costs, respectively, related to the August 2004 acquisition of Inland Resources. These amounts represent the recorded fair value of the oil and gas assets. The cash consideration paid in the acquisition was approximately $575 million.

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SUPPLEMENTARY FINANCIAL INFORMATION
SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

Capitalized costs for our oil and gas producing activities consisted of the following at the end of each of the years in the three-year period ended December 31, 2006:

	United States	United Kingdom	Malaysia	China	Other International	Total
			(In millions)			
December 31, 2006:						
Proved properties	$ 7,554	$ 170	$ 146	$ 67	$	$ 7,937
Unproved properties	856	32	63	2		953
	8,410	202	209	69		8,890
Accumulated depreciation, depletion and amortization	(3,202)	(2)	(27)	(4)		(3,235)
Net capitalized costs	$ 5,208	$ 200	$ 182	$ 65	$	$ 5,655
December 31, 2005:						
Proved properties	$ 6,015	$ 30	$ 67	$ 45	$	$ 6,157
Unproved properties	824	18	37		6	885
	6,839	48	104	45	6	7,042
Accumulated depreciation, depletion and amortization	(2,613)	(2)	(17)			(2,632)
Net capitalized costs	$ 4,226	$ 46	$ 87	$ 45	$ 6	$ 4,410
December 31, 2004:						
Proved properties	$ 5,030	$ 3	$ 47	$	$	$ 5,080
Unproved properties	738	25	16	37	12	828
	5,768	28	63	37	12	5,908
Accumulated depreciation, depletion and amortization	(2,125)	(2)	(6)			(2,133)
Net capitalized costs	$ 3,643	$ 26	$ 57	$ 37	$ 12	$ 3,775

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION
SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

Users of this information should be aware that the process of estimating quantities of proved and proved developed natural gas and crude oil reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir also may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time.

Estimated Net Quantities of Proved Oil and Gas Reserves

The following table sets forth our total net proved reserves and our total net proved developed reserves as of December 31, 2003, 2004, 2005 and 2006 and the changes in our total net proved reserves during the three-year period ended December 31, 2006, as estimated by our petroleum engineering staff:

	Oil, Condensate and Natural Gas Liquids (MMBbls)					Natural Gas (Bcf)			Total (Bcfe)			
	U.S.	U.K.	Malaysia	China	Total	U.S.	U.K.	Total	U.S.	U.K.	Malaysia	China
ped *ped*												
2003	37.8				37.8	1,087.6	2.6	1,090.2	1,314.2	2.6		
ates	1.2				1.2	(1.9)	(0.5)	(2.4)	5.3	(0.5)		
d other	5.3				5.3	230.9		230.9	262.4			
	47.8		6.6		54.4	131.4		131.4	418.2		39.6	
rties	(0.6)				(0.6)	(10.8)		(10.8)	(14.3)			
	(6.7)		(0.9)		(7.6)	(197.6)	(0.6)	(198.2)	(237.7)	(0.6)	(5.3)	
2004	84.8		5.7		90.5	1,239.6	1.5	1,241.1	1,748.1	1.5	34.3	
ates	0.8		(0.1)		0.7	10.7		10.7	15.6		(0.8)	
d other	9.2	0.8	4.7	5.3	20.0	249.3	64.1	313.4	304.5	69.2	28.0	31.5
	0.3				0.3	16.9		16.9	18.9			
rties	(0.2)				(0.2)	(6.1)	(1.3)	(7.4)	(7.1)	(1.2)		
	(8.4)		(1.3)		(9.7)	(183.2)	(0.2)	(183.4)	(233.8)	(0.1)	(7.7)	
2005	86.5	0.8	9.0	5.3	101.6	1,327.2	64.1	1,391.3	1,846.2	69.4	53.8	31.5

ates	2.2	(0.2)	(0.7)	0.3	1.6	(70.0)	(15.5)	(85.5)	(57.0)	(16.8)	(4.0)	2.1
d other	11.9	0.2	8.1		20.2	466.2	14.4	480.6	537.6	15.4	48.8	
						1.3		1.3	1.3			
rties		(0.1)			(0.1)	(0.1)	(11.8)	(11.9)	(0.2)	(12.7)		
	(7.8)		(0.9)	(0.3)	(9.0)	(189.6)		(189.6)	(236.1)		(5.6)	(1.7
2006	92.8	0.7	15.5	5.3	114.3	1,535.0	51.2	1,586.2	2,091.8	55.3	93.0	31.9
ped												
2003	30.7				30.7	955.8	2.5	958.3	1,139.9	2.6		
2004	49.7		5.7		55.4	1,003.9	1.4	1,005.3	1,302.2	1.4	34.3	
2005	54.6		4.3		58.9	1,010.2		1,010.2	1,338.0		25.8	
2006	60.9		2.4	1.8	65.1	1,093.6		1,093.6	1,458.9		14.6	10.6

(1) Substantially all of the purchases of U.S. oil, condensate and natural gas liquids relates to our August 2004 acquisition of Inland Resources.

All of our oil reserves in Malaysia and China are associated with production sharing contracts and are calculated using the economic interest method.

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NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION
SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)
Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following information was developed utilizing procedures prescribed by SFAS No. 69, Disclosures about Oil and Gas Producing Activities. The information is based on estimates prepared by our petroleum engineering staff. The standardized measure of discounted future net cash flows should not be viewed as representative of our current value. It and the other information contained in the following tables may be useful for certain comparative purposes, but should not be solely relied upon in evaluating us or our performance.

We believe that in reviewing the information that follows the following factors should be taken into account:

- future costs and sales prices will probably differ from those required to be used in these calculations;
- actual rates of production achieved in future years may vary significantly from the rates of production assumed in the calculations;
- a 10% discount rate may not be reasonable as a measure of the relative risk inherent in realizing future net oil and gas revenues; and
- future net revenues may be subject to different rates of income taxation.

Under the standardized measure, future cash inflows were estimated by applying year-end oil and gas prices applicable to our reserves to the estimated future production of year-end proved reserves. Future cash inflows do not reflect the impact of future production that is subject to open hedge positions (see Note 5, Commodity Derivative Instruments and Hedging Activities). Future cash inflows were reduced by estimated future development, abandonment and production costs based on year-end costs in order to arrive at net cash flows before tax. Future income tax expense has been computed by applying year-end statutory tax rates to aggregate future pre-tax net cash flows reduced by the tax basis of the properties involved and tax carryforwards. Use of a 10% discount rate and year-end prices and costs are required by SFAS No. 69.

In general, management does not rely on the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible outcomes.

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NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION
SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

The standardized measure of discounted future net cash flows from our estimated proved oil and gas reserves is as follows:

	U.S.	U.K.	Malaysia (In millions)	China	Total
2006:					
Future cash inflows	$ 12,922	$ 276	$ 930	$ 247	$ 14,375
Less related future:					
Production costs	(3,033)	(46)	(476)	(97)	(3,652)
Development and abandonment costs	(1,667)	(54)	(132)	(9)	(1,862)
Future net cash flows before income taxes	8,222	176	322	141	8,861
Future income tax expense	(2,309)	(97)	(121)	(51)	(2,578)
Future net cash flows before 10% discount	5,913	79	201	90	6,283
10% annual discount for estimating timing of cash flows	(2,727)	(15)	(66)	(28)	(2,836)
Standardized measure of discounted future net cash flows	$ 3,186	$ 64	$ 135	$ 62	$ 3,447
2005:					
Future cash inflows	$ 15,458	$ 658	$ 568	$ 268	$ 16,952
Less related future:					
Production costs	(2,688)	(65)	(334)	(55)	(3,142)
Development and abandonment costs	(1,192)	(146)	(47)	(27)	(1,412)
Future net cash flows before income taxes	11,578	447	187	186	12,398
Future income tax expense	(3,585)	(232)	(88)	(54)	(3,959)
Future net cash flows before 10% discount	7,993	215	99	132	8,439
10% annual discount for estimating timing of cash flows	(3,259)	(57)	(19)	(51)	(3,386)
Standardized measure of discounted future net cash flows	$ 4,734	$ 158	$ 80	$ 81	$ 5,053
2004:					
Future cash inflows	$ 10,718	$ 7	$ 219	$	$ 10,944
Less related future:					
Production costs	(2,067)	(4)	(127)		(2,198)

Development and abandonment costs	(886)	(1)	(10)		(897)
Future net cash flows before income taxes	7,765	2	82		7,849
Future income tax expense	(2,149)	(1)	(31)		(2,181)
Future net cash flows before 10% discount	5,616	1	51		5,668
10% annual discount for estimating timing of cash flows	(2,059)		(7)		(2,066)
Standardized measure of discounted future net cash flows	$ 3,557	$ 1	$ 44	$	$ 3,602

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NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION
SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

Set forth in the table below is a summary of the changes in the standardized measure of discounted future net cash flows for our proved oil and gas reserves during each of the years in the three-year period ended December 31, 2006:

	U.S.	U.K.	Malaysia (In millions)	China	Total
2006:					
Beginning of the period	$ 4,734	$ 158	$ 80	$ 81	$ 5,053
Revisions of previous estimates:					
Changes in prices and costs	(1,959)	(231)	(24)	(41)	(2,255)
Changes in quantities	(123)	(53)	(13)	7	(182)
Changes in future development costs	(196)	(14)			(210)
Development costs incurred during the period	326	110	33	19	488
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	958	38	88		1,084
Purchases and sales of reserves in place, net	2	(60)			(58)
Accretion of discount	679	32	16	11	738
Sales of oil and gas, net of production costs	(1,656)		(25)	(12)	(1,693)
Net change in income taxes	899	96	(12)	(2)	981
Production timing and other	(478)	(12)	(8)	(1)	(499)
Net increase (decrease)	(1,548)	(94)	55	(19)	(1,606)
End of the period	$ 3,186	$ 64	$ 135	$ 62	$ 3,447
2005:					
Beginning of the period	$ 3,557	$ 1	$ 44	$	$ 3,602
Revisions of previous estimates:					
Changes in prices and costs	1,729		25		1,754
Changes in quantities	(186)		(1)		(187)
Changes in future development costs	(91)				(91)
Development costs incurred during the period	180		(2)		178
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	1,103	324	81	111	1,619
Purchases and sales of reserves in place, net	18	(1)			17
Accretion of discount	356		5		361
Sales of oil and gas, net of production costs	(1,160)		(25)		(1,185)
Net change in income taxes	(738)	(166)	(49)	(30)	(983)
Production timing and other	(34)		2		(32)
Net increase	1,177	157	36	81	1,451

End of the period	$ 4,734	$ 158	$ 80	$ 81	$ 5,053
2004:					
Beginning of the period	$ 2,932	$ 3	$	$	$ 2,935
Revisions of previous estimates:					
Changes in prices and costs	157				157
Changes in quantities	(4)				(4)
Development costs incurred during the period	135				135
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	734				734
Purchases and sales of reserves in place, net	855		81		936
Accretion of discount	293				293
Sales of oil and gas, net of production costs	(1,130)	(1)	(11)		(1,142)
Net change in income taxes	(343)		(26)		(369)
Production timing and other	(72)	(1)			(73)
Net increase (decrease)	625	(2)	44		667
End of the period	$ 3,557	$ 1	$ 44	$	$ 3,602

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

None.

Item 9A. ***Controls and Procedures***

Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2006 in ensuring that material information was accumulated and communicated to management, and made known to our Chief Executive Officer and Chief Financial Officer, on a timely basis to allow disclosure as required in this report.

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

The information required to be furnished pursuant to this item is set forth under the captions Management s Report on Internal Control over Financial Reporting and Report of Independent Registered Public Accounting Firm in Item 8 of this report.

Changes in Internal Control over Financial Reporting

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the fourth quarter of 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting or in other factors that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Item 9B. ***Other Information***

None.

PART III

Item 10. *Directors and Executive Officers of the Registrant*

The information required by Item 10 of Form 10-K is incorporated herein by reference to such information as set forth in the proxy statement for our 2007 annual meeting of stockholders to be held on May 3, 2007 and to the information set forth in Item 4A of this report.

Corporate Code of Business Conduct and Ethics

We have adopted a corporate code of business conduct and ethics for directors, officers (including our principal executive officer, principal financial officer and controller or principal accounting officer) and employees. Our corporate code includes a financial code of ethics applicable to our chief executive officer, chief financial officer and controller or chief accounting officer. Both of these codes are available on our website at *www.newfield.com.* Stockholders may request a free copy of these codes from:

Newfield Exploration Company
Attention: Investor Relations
363 North Sam Houston Parkway East, Suite 2020
Houston, Texas 77060
(281) 405-4284

Corporate Governance Guidelines

We have adopted corporate governance guidelines, which are available on our website. Stockholders may request a free copy of our corporate governance guidelines from the address and phone number set forth above under Corporate Code of Business Conduct and Ethics.

Committee Charters

The charters of the Audit Committee, the Compensation & Management Development Committee and the Nominating & Corporate Governance Committee of our Board of Directors are available on our website. Stockholders may request a free copy of any of these charters from the address and phone number set forth above under Corporate Code of Business Conduct and Ethics.

Section 16(a) Beneficial Ownership Reporting Compliance

Information regarding Section 16(a) beneficial ownership reporting compliance is incorporated herein by reference to such information as set forth in the proxy statement for our 2007 annual meeting of stockholders to be held on May 3, 2007.

Certifications

The New York Stock Exchange requires the chief executive officer of each listed company to certify annually that he or she is not aware of any violation by the company of the NYSE corporate governance listing standards as of the date of the certification, qualifying the certification to the extent necessary. Our chief executive officer provided such certification to the NYSE in 2006. In addition, the certifications of our chief executive officer and chief financial officer required by Section 302 of the Sarbanes-Oxley Act have been filed as exhibits to this report and to our annual report on Form 10-K for the year ended December 31, 2005.

Item 11. ***Executive Compensation***

The information required by Item 11 of Form 10-K is incorporated herein by reference to such information as set forth in the proxy statement for our 2007 annual meeting.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information required by Item 12 of Form 10-K is incorporated herein by reference to such information as set forth in the proxy statement for our 2007 annual meeting.

Item 13. ***Certain Relationships and Related Transactions***

The information required by Item 13 of Form 10-K is incorporated herein by reference to such information as set forth in the proxy statement for our 2007 annual meeting.

Item 14. ***Principal Accountant Fees and Services***

The information required by Item 14 of Form 10-K is incorporated herein by reference to such information as set forth in the proxy statement for our 2007 annual meeting.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

Financial Statements

Reference is made to the index set forth on page 48 of this report.

Financial Statement Schedules

Financial statement schedules listed under SEC rules but not included in this report are omitted because they are not applicable or the required information is provided in the notes to our consolidated financial statements.

Exhibits

Exhibit Number	Title
3.1	Second Restated Certificate of Incorporation of Newfield (incorporated by reference to Exhibit 3.1 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 1-12534))
3.1.1	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 15, 1997 (incorporated by reference to Exhibit 3.1.1 to Newfield s Registration Statement on Form S-3 (Registration No. 333-32582))
3.1.2	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 12, 2004 (incorporated by reference to Exhibit 4.2.3 to Newfield s Registration Statement on Form S-8 (Registration No. 333-116191))
3.1.3	Certificate of Designation of Series A Junior Participating Preferred Stock, par value $0.01 per share, setting forth the terms of the Series A Junior Participating Preferred Stock, par value $0.01 per share (incorporated by reference to Exhibit 3.5 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 1-12534))
3.2	Restated Bylaws of Newfield (as amended by Amendment No. 1 thereto adopted January 31, 2000 and Amendment No. 2 thereto adopted July 28, 2005) (incorporated by reference to Exhibit 3.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2005 (File No. 1-12534))
4.1	Rights Agreement, dated as of February 12, 1999, between Newfield and ChaseMellon Shareholder Services L.L.C., as Rights Agent, specifying the terms of the Rights to Purchase Series A Junior Participating Preferred Stock, par value $0.01 per share, of Newfield (incorporated by reference to Exhibit 1 to Newfield s Registration Statement on Form 8-A filed with the SEC on February 18, 1999 (File No. 1-12534))
4.2	Indenture dated as of October 15, 1997 among Newfield, as issuer, and Wachovia Bank, National Association (formerly First Union National Bank), as trustee (incorporated by reference to Exhibit 4.3 to Newfield s Registration Statement on Form S-4 (Registration No. 333-39563))
4.3	Senior Indenture dated as of February 28, 2001 between Newfield and Wachovia Bank, National Association (formerly First Union National Bank), as Trustee (incorporated by reference to Exhibit 4.1 to Newfield s Current Report on Form 8-K filed with the SEC on February 28, 2001 (File No. 1-12534))

4.4	Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association (formerly First Union National Bank), as Trustee (incorporated by reference to Exhibit 4.5 of Newfield s Registration Statement on Form S-3 (Registration No. 333-71348))

Exhibit Number	Title
4.4.1	Second Supplemental Indenture, dated as of August 18, 2004, to Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.6.3 to Newfield s Registration Statement on Form S-4 (Registration No. 333-122157))
4.4.2	Third Supplemental Indenture, dated as of April 3, 2006, to Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4.3 of Newfield s Current Report on Form 8-K filed with the SEC on April 3, 2006 (File No. 1-12534))
10.1	Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 4.1 to Newfield s Registration Statement on Form S-8 (Registration No. 33-92182))
10.1.1	First Amendment to Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 10.1 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
10.1.2	Second Amendment to Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 99.1 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
10.2	Newfield Exploration Company 1998 Omnibus Stock Plan (incorporated by reference to Exhibit 4.1.1 to Newfield s Registration Statement on Form S-8 (Registration No. 333-59383))
10.2.1	Amendment of 1998 Omnibus Stock Plan, dated May 7, 1998 (incorporated by reference to Exhibit 4.1.2 to Newfield s Registration Statement on Form S-8 (Registration No. 333-59383))
10.2.2	Second Amendment to Newfield Exploration Company 1998 Omnibus Stock Plan (as amended on May 7, 1998) (incorporated by reference to Exhibit 10.2 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
10.2.3	Third Amendment to Newfield Exploration Company 1998 Omnibus Stock Plan (incorporated by reference to Exhibit 99.2 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
10.3	Newfield Exploration Company 2000 Omnibus Stock Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 10.7.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2001 (File No. 1-12534))
10.3.1	First Amendment to Newfield Exploration Company 2000 Omnibus Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 10.3 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
10.3.2	Second Amendment to Newfield Exploration Company 2000 Omnibus Stock Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 99.3 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
10.3.3	Form of TSR 2003 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf and Mark J. Spicer dated as of February 12, 2003 (incorporated by reference to Exhibit 10.3.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 1-12534))
10.4	Amended and Restated Newfield Exploration Company 2004 Omnibus Stock Plan (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K/A filed with the SEC on March 1, 2007 (File No. 1-12534))

Exhibit Number	Title
10.4.1	Form of TSR 2005 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf, Mark J. Spicer, Brian L. Rickmers and Susan G. Riggs dated as of February 8, 2005 (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K filed with the SEC on February 11, 2005 (File No. 1-12534))
10.4.2	Form of TSR 2006 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf, Mark J. Spicer, Brian L. Rickmers and Susan G. Riggs dated as of February 14, 2006 (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K/A filed with the SEC on February 21, 2006 (File No. 1-12534))
10.4.3	Form of TSR 2007 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Michael Van Horn, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, John H. Jasek, Gary D. Packer and James T. Zernell dated as of February 14, 2007 (incorporated by reference to Exhibit 10.2 to Newfield s Current Report on Form 8-K filed with the SEC on February 21, 2007 (File No. 1-12534))
10.4.4	Form of 2007 Restricted Unit Agreement between Newfield and each of David A. Trice, David F. Schaible, Michael Van Horn, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, John H. Jasek, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf, Brian L. Rickmers and Susan G. Riggs dated as of February 14, 2007 (incorporated by reference to Exhibit 10.3 to Newfield s Current Report on Form 8-K filed with the SEC on February 21, 2007 (File No. 1-12534))
10.5	Newfield Exploration Company 2000 Non-Employee Director Restricted Stock Plan (incorporated by reference to Exhibit 10.18 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 1-12534))
* 10.5.1	First Amendment to Newfield Exploration Company 2000 Non-Employee Director Restricted Stock Plan
10.6	Newfield Employee 1993 Incentive Compensation Plan (incorporated by reference to Exhibit 10.5 to Newfield s Registration Statement on Form S-1 (Registration No. 33-69540))
10.6.1	Amendment to Newfield Employee 1993 Incentive Compensation Plan (effective as of February 14, 2002) (incorporated by reference to Exhibit 10.9.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2001 (File No. 1-12534))
10.7	Amended and Restated Newfield Exploration Company 2003 Incentive Compensation Plan (incorporated by reference to Exhibit 10.7 to Newfield s Annual Report on Form 10-K for the year ended December 1, 2004 (File No. 1-12534))
10.8	Newfield Exploration Company Deferred Compensation Plan (incorporated by reference to Exhibit 10.11 to Newfield s Registration Statement on Form S-3 (Registration No. 333-32587))
10.9	Newfield Exploration Company Change of Control Severance Plan (incorporated by reference to Exhibit 10.9 to Newfield s Annual Report on Form 10-K for the year ended December 1, 2004 (File No. 1-12534))
10.9.1	

	First Amendment to Newfield Exploration Company Change of Control Severance Plan (incorporated by reference to Exhibit 10.3 to Newfield s Current Report on Form 8-K/A filed with the SEC on February 21, 2006 (File No. 1-12534))
10.10.1	Form of Change of Control Severance Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliot Pew and Terry W. Rathert dated effective as of February 17, 2005 (incorporated by reference to Exhibit 10.10 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 1-12534))

Exhibit Number	Title
10.10.2	Form of Change of Control Severance Agreement between Newfield and each of Lee K. Boothby, George T. Dunn, Gary D. Packer and William D. Schneider dated effective as of February 17, 2005 (incorporated by reference to Exhibit 10.11 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 1-12534))
10.10.3	Form of First Amendment to Change of Control Severance Agreement between Newfield and each executive officer who is a party to such an agreement (incorporated by reference to Exhibit 10.2 to Newfield s Current Report on Form 8-K/A filed with the SEC on February 21, 2006 (File No. 1-12534))
10.11	Form of Indemnification Agreement between Newfield and each of its directors and executive officers (incorporated by reference to Exhibit 10.1 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2005 (File No. 1-12534))
10.12	Resolution of Members Establishing the Preferences, Limitations and Relative Rights of Series A Preferred Shares of Huffco China, LDC dated May 14, 1997 (incorporated by reference to Exhibit 10.15 to Newfield s Registration Statement on Form S-3 (Registration No. 333-32587))
10.13	Credit Agreement, dated as of December 2, 2005, among Newfield Exploration Company, JP Morgan Chase Bank, N.A., as Administrative Agent and a lender, and the other agents and lenders party thereto (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K filed with the SEC on December 6, 2005 (File No. 1-12534))
21.1	List of Significant Subsidiaries (incorporated by reference to Exhibit 21.1 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2005 (File No. 1-12534))
*23.1	Consent of PricewaterhouseCoopers LLP
*31.1	Certification of Chief Executive Officer of Newfield Exploration Company pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31.2	Certification of Chief Financial Officer of Newfield Exploration Company pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*32.1	Certification of Chief Executive Officer of Newfield Exploration Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32.2	Certification of Chief Financial Officer of Newfield Exploration Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Filed or furnished herewith.

Identifies management contracts and compensatory plans or arrangements.

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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, on the 1st day of March, 2007.

NEWFIELD EXPLORATION COMPANY

By: /s/ DAVID A. TRICE
David A. Trice
Chairman, President and Chief Executive 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 indicated and on the 1st day of March, 2007.

Signature	Title
/s/ DAVID A. TRICE David A. Trice	Chairman, President and Chief Executive Officer and Director (Principal Executive Officer)
/s/ TERRY W. RATHERT Terry W. Rathert	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ BRIAN L. RICKMERS Brian L. Rickmers	Controller (Principal Accounting Officer)
/s/ PHILIP J. BURGUIERES Philip J. Burguieres	Director
/s/ PAMELA J. GARDNER Pamela J. Gardner	Director
/s/ DENNIS HENDRIX Dennis Hendrix	Director
/s/ JOHN R. KEMP III John R. Kemp III	Director
/s/ J. MICHAEL LACEY J. Michael Lacey	Director
/s/ JOSEPH H. NETHERLAND Joseph H. Netherland	Director
/s/ HOWARD H. NEWMAN Howard H. Newman	Director

/s/ THOMAS G. RICKS Thomas G. Ricks	Director

Signature	Title
/s/ JUANITA F. ROMANS Juanita F. Romans	Director
/s/ DAVID F. SCHAIBLE David F. Schaible	Director
/s/ C. E. SHULTZ C. E. Shultz	Director
/s/ J. TERRY STRANGE J. Terry Strange	Director

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EXHIBIT INDEX

Exhibit Number	Title
3.1	Second Restated Certificate of Incorporation of Newfield (incorporated by reference to Exhibit 3.1 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 1-12534))
3.1.1	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 15, 1997 (incorporated by reference to Exhibit 3.1.1 to Newfield s Registration Statement on Form S-3 (Registration No. 333-32582))
3.1.2	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 12, 2004 (incorporated by reference to Exhibit 4.2.3 to Newfield s Registration Statement on Form S-8 (Registration No. 333-116191))
3.1.3	Certificate of Designation of Series A Junior Participating Preferred Stock, par value $0.01 per share, setting forth the terms of the Series A Junior Participating Preferred Stock, par value $0.01 per share (incorporated by reference to Exhibit 3.5 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 1-12534))
3.2	Restated Bylaws of Newfield (as amended by Amendment No. 1 thereto adopted January 31, 2000 and Amendment No. 2 thereto adopted July 28, 2005) (incorporated by reference to Exhibit 3.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2005 (File No. 1-12534))
4.1	Rights Agreement, dated as of February 12, 1999, between Newfield and ChaseMellon Shareholder Services L.L.C., as Rights Agent, specifying the terms of the Rights to Purchase Series A Junior Participating Preferred Stock, par value $0.01 per share, of Newfield (incorporated by reference to Exhibit 1 to Newfield s Registration Statement on Form 8-A filed with the SEC on February 18, 1999 (File No. 1-12534))
4.2	Indenture dated as of October 15, 1997 among Newfield, as issuer, and Wachovia Bank, National Association (formerly First Union National Bank), as trustee (incorporated by reference to Exhibit 4.3 to Newfield s Registration Statement on Form S-4 (Registration No. 333-39563))
4.3	Senior Indenture dated as of February 28, 2001 between Newfield and Wachovia Bank, National Association (formerly First Union National Bank), as Trustee (incorporated by reference to Exhibit 4.1 to Newfield s Current Report on Form 8-K filed with the SEC on February 28, 2001 (File No. 1-12534))
4.4	Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association (formerly First Union National Bank), as Trustee (incorporated by reference to Exhibit 4.5 of Newfield s Registration Statement on Form S-3 (Registration No. 333-71348))
4.4.1	Second Supplemental Indenture, dated as of August 18, 2004, to Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.6.3 to Newfield s Registration Statement on Form S-4 (Registration No. 333-122157))
4.4.2	Third Supplemental Indenture, dated as of April 3, 2006, to Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4.3 of Newfield s Current Report on Form 8-K filed with the SEC on April 3, 2006 (File No. 1-12534))
10.1	Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 4.1 to Newfield s Registration Statement on Form S-8 (Registration No. 33-92182))
10.1.1	

	First Amendment to Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 10.1 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
10.1.2	Second Amendment to Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 99.1 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))

Exhibit Number	Title
10.2	Newfield Exploration Company 1998 Omnibus Stock Plan (incorporated by reference to Exhibit 4.1.1 to Newfield s Registration Statement on Form S-8 (Registration No. 333-59383))
10.2.1	Amendment of 1998 Omnibus Stock Plan, dated May 7, 1998 (incorporated by reference to Exhibit 4.1.2 to Newfield s Registration Statement on Form S-8 (Registration No. 333-59383))
10.2.2	Second Amendment to Newfield Exploration Company 1998 Omnibus Stock Plan (as amended on May 7, 1998) (incorporated by reference to Exhibit 10.2 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
10.2.3	Third Amendment to Newfield Exploration Company 1998 Omnibus Stock Plan (incorporated by reference to Exhibit 99.2 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
10.3	Newfield Exploration Company 2000 Omnibus Stock Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 10.7.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2001 (File No. 1-12534))
10.3.1	First Amendment to Newfield Exploration Company 2000 Omnibus Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 10.3 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
10.3.2	Second Amendment to Newfield Exploration Company 2000 Omnibus Stock Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 99.3 to Newfield s Current Report on Form 8-K filed with the SEC on May 5, 2005 (File No. 1-12534))
10.3.3	Form of TSR 2003 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf and Mark J. Spicer dated as of February 12, 2003 (incorporated by reference to Exhibit 10.3.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 1-12534))
10.4	Amended and Restated Newfield Exploration Company 2004 Omnibus Stock Plan (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K/A filed with the SEC on March 1, 2007 (File No. 1-12534))
10.4.1	Form of TSR 2005 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf, Mark J. Spicer, Brian L. Rickmers and Susan G. Riggs dated as of February 8, 2005 (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K filed with the SEC on February 11, 2005 (File No. 1-12534))
10.4.2	Form of TSR 2006 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Elliott Pew, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf, Mark J. Spicer, Brian L. Rickmers and Susan G. Riggs dated as of February 14, 2006 (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K/A filed with the SEC on February 21, 2006 (File No. 1-12534))
10.4.3	Form of TSR 2007 Restricted Stock Agreement between Newfield and each of David A. Trice, David F. Schaible, Michael Van Horn, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, John H. Jasek, Gary D. Packer and James T. Zernell dated as of February 14, 2007 (incorporated by reference to Exhibit 10.2 to Newfield s Current Report on Form 8-K filed with the SEC on February 21, 2007 (File No. 1-12534))

Exhibit Number	Title
10.4.4	Form of 2007 Restricted Unit Agreement between Newfield and each of David A. Trice, David F. Schaible, Michael Van Horn, Terry W. Rathert, William D. Schneider, Lee K. Boothby, George T. Dunn, John H. Jasek, Gary D. Packer, James T. Zernell, Mona Leigh Bernhardt, William Mark Blumenshine, Stephen C. Campbell, James J. Metcalf, Brian L. Rickmers and Susan G. Riggs dated as of February 14, 2007 (incorporated by reference to Exhibit 10.3 to Newfield s Current Report on Form 8-K filed with the SEC on February 21, 2007 (File No. 1-12534))
10.5	Newfield Exploration Company 2000 Non-Employee Director Restricted Stock Plan (incorporated by reference to Exhibit 10.18 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 1-12534))
* 10.5.1	First Amendment to Newfield Exploration Company 2000 Non-Employee Director Restricted Stock Plan
10.6	Newfield Employee 1993 Incentive Compensation Plan (incorporated by reference to Exhibit 10.5 to Newfield s Registration Statement on Form S-1 (Registration No. 33-69540))
10.6.1	Amendment to Newfield Employee 1993 Incentive Compensation Plan (effective as of February 14, 2002) (incorporated by reference to Exhibit 10.9.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2001 (File No. 1-12534))
10.7	Amended and Restated Newfield Exploration Company 2003 Incentive Compensation Plan (incorporated by reference to Exhibit 10.7 to Newfield s Annual Report on Form 10-K for the year ended December 1, 2004 (File No. 1-12534))
10.8	Newfield Exploration Company Deferred Compensation Plan (incorporated by reference to Exhibit 10.11 to Newfield s Registration Statement on Form S-3 (Registration No. 333-32587))
10.9	Newfield Exploration Company Change of Control Severance Plan (incorporated by reference to Exhibit 10.9 to Newfield s Annual Report on Form 10-K for the year ended December 1, 2004 (File No. 1-12534))
10.9.1	First Amendment to Newfield Exploration Company Change of Control Severance Plan (incorporated by reference to Exhibit 10.3 to Newfield s Current Report on Form 8-K/A filed with the SEC on February 21, 2006 (File No. 1-12534))
10.10.1	Form of Change of Control Severance Agreement between Newfield and each of David A. Trice, David F. Schaible Elliot Pew and Terry W. Rathert dated effective as of February 17, 2005 (incorporated by reference to Exhibit 10.10 to Newfield s Annual Report on Form 10-K for the year ended December 1, 2004 (File No. 1-12534))
10.10.2	Form of Change of Control Severance Agreement between Newfield and each of Lee K. Boothby, George T. Dunn, Gary D. Packer and William D. Schneider dated effective as of February 17, 2005 (incorporated by reference to Exhibit 10.11 to Newfield s Annual Report on Form 10-K for the year ended December 1, 2004 (File No. 1-12534))
10.10.3	Form of First Amendment to Change of Control Severance Agreement between Newfield and each executive officer who is a party to such an agreement (incorporated by reference to Exhibit 10.2 to Newfield s Current Report on Form 8-K/A filed with the SEC on February 21, 2006 (File No. 1-12534))
10.11	Form of Indemnification Agreement between Newfield and each of its directors and executive officers (incorporated by reference to Exhibit 10.1 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2005 (File No. 1-12534))
10.12	Resolution of Members Establishing the Preferences, Limitations and Relative Rights of Series A Preferred Shares of Huffco China, LDC dated May 14, 1997 (incorporated by reference to

	Exhibit 10.15 to Newfield s Registration Statement on Form S-3 (Registration No. 333-32587))
10.13	Credit Agreement, dated as of December 2, 2005, among Newfield Exploration Company, JP Morgan Chase Bank, N.A., as Administrative Agent and a lender, and the other agents and lenders party thereto (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K filed with the SEC on December 6, 2005 (File No. 1-12534))

Exhibit Number	Title
21.1	List of Significant Subsidiaries (incorporated by reference to Exhibit 21.1 to Newfield s Annual Report on Form 10-K for the year ended December 1, 2005 (File No. 1-12534))
*23.1	Consent of PricewaterhouseCoopers LLP
*31.1	Certification of Chief Executive Officer of Newfield Exploration Company pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31.2	Certification of Chief Financial Officer of Newfield Exploration Company pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*32.1	Certification of Chief Executive Officer of Newfield Exploration Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32.2	Certification of Chief Financial Officer of Newfield Exploration Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Filed or furnished herewith.

Identifies management contracts and compensatory plans or arrangements.