REMINGTON OIL & GAS CORP
Form 10-K
March 14, 2006

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

Form 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2005

OR

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 1-11516

REMINGTON OIL AND GAS CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**75-2369148**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. employer identification no.)*
8201 Preston Road, Suite 600, Dallas, Texas	**75225-6211**
(Address of principal executive offices)	*(Zip code)*

Registrant s telephone number, including area code:
(214) 210-2650

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $0.01 Par Value	**New York Stock Exchange**

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:
Common Stock, $0.01 Par Value
(Title of Class)

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 Section 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 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. þ

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 by Rule 12b-2 of the Act). Yes o No þ

The aggregate market value of common stock held by non-affiliates of the registrant as of June 30, 2005 was $834,848,249. On March 10, 2006, the number of outstanding shares of common stock, $0.01 par value, was 28,842,084.

DOCUMENTS INCORPORATED BY REFERENCE

FORM 10-K

REMINGTON OIL AND GAS CORPORATION

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PART I

Item 1. *Business.*

General

Remington Oil and Gas Corporation

Incorporated 1991, Delaware

Address 8201 Preston Road, Suite 600, Dallas, Texas 75225-6211

Telephone number (214) 210-2650

Website *www.remoil.net* Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available on our website under the link SEC Filings as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission (SEC). Further, our website contains our corporate governance documents, including our Corporate Governance Guidelines and our Code of Business Conduct and Ethics, which apply to all directors and employees, including our Chief Executive Officer, Principal Financial Officer, and Principal Accounting Officer. Also included on the website as part of our corporate governance documents are our By-Laws and the charters for our Audit, Nominating and Corporate Governance, Compensation, and Executive Committees. Persons may obtain free of charge a copy of the reports listed above and our corporate governance documents by written request to the Secretary of the Company. Additional information on our website includes Whistle Blower procedures, recent investor presentations, company contacts and recent press releases. Information on our website is not incorporated into this report on Form 10-K.

40 employees on December 31, 2005

Our primary business operation is exploration, development, and production of oil and gas reserves in the offshore Gulf of Mexico and onshore Gulf Coast areas. All of our assets are located in these areas and all of our revenues and expenses are generated in these same regions of the United States.

Proposed Merger with Helix Energy Solutions Group, Inc.

On January 22, 2006, we entered into a merger agreement with Helix Energy Solutions Group, Inc. under which Helix will acquire us. Upon the consummation of the merger, our shareholders will receive $27.00 in cash and 0.436 of a share of Helix common stock for each share of our stock held. The merger is subject to the approval of our stockholders and clearance by certain governmental authorities. We and Helix will file a proxy statement/prospectus and other relevant documents concerning the proposed merger and the special meeting of our stockholders which will be called seeking approval of the transaction.

Long-Term Strategy

Our long-term strategy is to increase our oil and gas reserves and production while keeping our finding and development costs and operating costs competitive with our industry peers. We implement this strategy through drilling exploratory and development wells from an inventory of available prospects that we have evaluated for geologic and mechanical risk and future reserve potential. Our drilling program will contain some high risk/high reserve potential opportunities as well as some lower risk/lower reserve potential opportunities, in order to attempt to deliver a balanced program of reserve and production growth. Success of this strategy is contingent on various risk factors as discussed in our filings with the SEC.

Activities and Operations

We identify prospective oil and gas properties primarily by using 3-D seismic technology. After acquiring an interest in a prospective property, we drill one or more exploratory wells. If the exploratory wells find commercial oil and/or gas, we complete the wells and begin producing the oil or gas. Because most of our operations are located in the offshore Gulf of Mexico, we must install facilities such as offshore platforms and gathering pipelines in order to produce the oil and gas and deliver it to the marketplace. Certain properties require additional drilling to fully develop the oil and gas reserves and maximize the production from a particular discovery. In order to increase our

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oil and gas reserves and production, we continually reinvest our net operating cash flow into new or existing exploration, development, and acquisition activities.

We share ownership in our oil and gas properties with various industry participants. We currently operate the majority of our offshore properties. An operator is generally able to maintain a greater degree of control over the timing and amount of capital expenditures than can a non-operating interest owner.

Competition in the Oil and Gas Industry

We compete with:

- Large integrated oil and gas companies
- Independent exploration and production companies
- Private individuals
- Sponsored drilling programs

We compete for:

- Operational, technical, and support staff
- Options and/or leases on properties
- Markets for the sale of oil and gas production
- Access to capital

Many of our competitors may have significantly more financial, personnel, technological, and other resources available. In addition, some of the larger integrated companies may be better able to respond to industry changes including price fluctuations, oil and gas demands, and governmental regulations.

Markets for Oil and Gas Production

Oil and gas are generally homogenous commodities, and the market prices for these commodities fluctuate significantly. Purchasers adjust prices for quality, refined product yield, geographic proximity to refineries or major market centers, and the availability of transportation pipelines or facilities. Outside factors beyond our control combine to influence the market prices. Some of the more critical factors that affect oil and gas commodity prices include the following:

- Changes in supply and demand
- Changes in refinery utilization
- Levels of economic activity throughout the country
- Seasonal or extraordinary weather patterns

Political developments throughout the world

We have no real ability to influence or predict the market prices. Therefore, we normally sell our oil and gas production based on posted market prices, spot market indices, or prices derived from the posted price or index. At times we will lock in a fixed price for a portion of our future production to be delivered as it is produced. We use an independent company to market almost all of our offshore gas production and a portion of our offshore oil production. Because oil and gas are homogenous commodities and other customers and marketers are readily available, we believe that the loss of any of our current customers or our independent marketing company would not be detrimental to our operations nor have a material effect on our revenues.

Securities Regulation and Corporate Governance

We are a publicly traded company with our common stock listed for trading on The New York Stock Exchange. Because our securities are traded in the public markets, we are subject to regulation by governmental and private organizations such as the SEC and The New York Stock Exchange. This regulatory oversight imposes on us the responsibility for establishing and maintaining disclosure controls and procedures. The objective of those controls and procedures is to ensure that material information relating to us is made known to our management and that the financial statements and other information included in this Form 10-K and other reports and documents filed with the SEC do not contain any untrue statement of material fact, or omit to state a material fact, necessary to make the statements made in this Form 10-K and those other reports and documents not misleading. Our compliance with the increasing scope of regulation has significantly increased our audit and internal control costs.

Seven members serve on our Board of Directors. Five of these members are independent outside directors while the other two are our Chairman and Chief Executive Officer, and our President and Chief Operating Officer. We have a lead independent director whose responsibilities are set forth in our corporate governance documents.

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The Board has established four standing committees: Audit, Compensation, Nominating and Corporate Governance, and Executive. The members of the Audit, Compensation, and Nominating and Corporate Governance Committees are all independent directors. Two of the three members of the Executive Committee are independent directors. Each standing committee is governed by its own charter.

Upon consummation of the proposed merger, our stock will cease to be traded. Shares of Helix common stock are traded on the Nasdaq National Market System.

Governmental Regulation, Including Environmental Regulation of Oil and Gas Operations

Numerous federal and state regulations affect our oil and gas operations. Current regulations are constantly reviewed by the various agencies at the same time that new regulations are being considered and implemented. In addition, because we hold federal leases, the federal government requires us to comply with numerous regulations that focus on government contractors. The regulatory burden upon the oil and gas industry increases the cost of doing business and consequently affects our profitability.

State regulations relate to virtually all aspects of the oil and gas business including drilling permits, bonds, and operation reports. In addition, many states have regulations relating to pooling of oil and gas properties, maximum rates of production, and spacing and plugging and abandonment of wells.

Our oil and gas operations are subject to stringent federal, state, and local environmental laws and regulations. Environmental laws and regulations are complex, change frequently, and have tended to become more restrictive over time. Many environmental laws require permits from governmental authorities before construction on a project may be commenced or before wastes or other materials may be discharged into the environment. The process for obtaining necessary permits can be lengthy and complex, and can sometimes result in the establishment of permit conditions that make the project or activity for which the permit was sought either unprofitable or otherwise unattractive. Even where permits are not required, compliance with environmental laws and regulations can require significant capital and operating expenditures, and we may be required to incur costs to remediate contamination from past releases of wastes into the environment. Failure to comply with these statutes, rules and regulations may result in the assessment of administrative, civil and even criminal penalties. The most significant environmental obligations applicable to our operations relate to compliance with the federal Oil Pollution Act and the Clean Water Act. The Oil Pollution Act and its implementing regulations (OPA) establish requirements for the prevention of oil spills and impose liability for damages resulting from spills into waters of the United States. The OPA also requires that operators of offshore oil production facilities, such as our facilities in the Gulf of Mexico, demonstrate to the U.S. Minerals Management Service that they possess at least $35.0 million in financial resources available to pay for costs that may be incurred in responding to an oil spill. The Clean Water Act and its implementing regulations impose restrictions and strict controls on the discharge of wastes into the waters of the United States, including discharges of oil, produced water and sand, drilling fluids, drill cuttings, and other wastes typically generated by the oil and gas industry. Although we believe that we are in compliance with the requirements of the OPA and Clean Water Act, as well as the other statutes and associated regulations governing the discharge of materials into the environment, the cost of compliance with this federal and state legislation could have a significant impact on our financial ability to carry out our oil and gas operations.

Our operations are also subject to environmental laws and regulations that impose requirements for remediation of soil and groundwater contamination. In many cases, these laws apply retroactively to previous waste disposal practices regardless of fault, legality of the original activities, or ownership or control of sites. A company could be subject to severe fines and cleanup costs if found liable under these laws. We have never been a liable party under these laws nor have we been named a potentially responsible party for waste disposal at any site. However, we do own and operate onshore properties that were previously owned and operated by companies whose waste disposal practices, while legal and standard within the industry at the time they occurred, may have resulted in on-site contamination that may require remedial action under current standards. There can be no assurance that we will not be required to undertake remedial actions for such instances of contamination in connection with our ownership and operation of these properties, or that the costs associated with such remedial actions will be fully covered by insurance.

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Other Business Information

Except for our oil and gas leases with third parties and licenses to acquire or use seismic data, we have no material patents, licenses, franchises, or concessions that we consider significant to our oil and gas operations. We do not have any backlog of products, customer orders, or inventory. We have not been a party to any bankruptcy, reorganization, adjustment or similar proceeding except in the capacity as a creditor.

Item 1A. *Risk Factors*

Not completing the merger could negatively impact our stock price and future results

Although our board of directors will, subject to fiduciary exceptions, recommend that our stockholders approve and adopt the merger agreement, there is no assurance that the merger agreement and the merger will be approved, and there is no assurance that the other conditions to the completion of the merger will be satisfied. If the merger is not completed, we will be subject to several risks, including the following:

We may be required to pay Helix the sum of (i) Helix s documented out of pocket fees and expenses incurred or paid by or on behalf of Helix in connection with the merger or the consummation of any of the transactions contemplated by the merger agreement, including all regulatory filing fees, fees and expenses of counsel, commercial banks, investment banking firms, accountants, experts, environmental consultants, and other consultants to Helix, up to a maximum amount not to exceed $2 million, and (ii) $45 million if the merger agreement is terminated under certain circumstances and we enter into or complete an alternative transaction;

The current market price of our common stock may reflect a market assumption that the merger will occur, and a failure to complete the merger could result in a negative perception of us by the stock market and a resulting decline in the market price of our common stock;

Certain costs relating to the merger (such as legal, accounting and financial advisory fees) are payable by us whether or not the merger is completed; and

There may be substantial disruption to our business and a distraction of our management and employees from day-to-day operations, because matters related to the merger (including integration planning) may require substantial commitments of time and resources, which could otherwise have been devoted to other opportunities that could have been beneficial to us;

In addition, we would not realize any of the expected benefits of having completed the merger. If the merger is not completed, these risks may materialize and materially adversely affect our business, financial results, financial condition and stock price.

Natural gas and oil prices are volatile, which makes future revenue uncertain.

Our financial condition and results of operations depend on the prices we receive for the oil and gas we produce. The market prices for oil and gas are subject to fluctuation in response to events beyond our control, such as:

supply of and demand for oil and gas;

market uncertainty;

worldwide political and economic instability; and government regulations.

Oil and gas prices have historically been volatile, and such volatility is likely to continue. Our ability to estimate the value of producing properties for acquisition and to budget and project the financial return of exploration and development projects is made more difficult by this volatility. A dramatic decline in such prices could have a substantial and material effect on:

our revenues;

financial condition:

results of operations;

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our ability to increase production and grow reserves in an economically efficient manner; and

our access to capital.

A resulting significant decline in our cash flows from operations could cause us to fail to meet our operational obligations, thus requiring us to modify our capital expenditure program which could then affect our ability to find and develop reserves and our level of production. Moreover, such a decline could affect the measure of the discounted future net cash flow of reserves, which could then affect our borrowing base and may increase the likelihood that we will incur impairment charges on our oil and gas properties for financial accounting purposes.

Our future success depends on our ability to economically increase our reserves and production, which historically have had relatively short production lives.

Our future success will depend on our ability to find, develop or acquire additional economically recoverable oil and gas reserves and convert these reserves to production. Because our proved reserves will normally decline as they are produced, we must maintain successful exploration and development activities in order to replace reserves depleted through production. We may not be able to replace our reserves in an economically viable manner.

Our forward sales decisions regarding some of our production may reduce our potential gains from increases in oil and gas prices.

Oil and gas prices can fluctuate significantly and have a direct impact on our reserves. To manage our exposure to the risks inherent in such a volatile market, from time to time, we have forward sold for future physical delivery an amount, not more than half, of our future production. This means that a portion of our production is sold at a fixed price as a shield against dramatic price declines that could occur in the market. We may from time to time engage in other hedging activities that limit our upside potential from price increases. These sales activities may limit our benefit from dramatic price increase. The merger agreement requires that prior to the consummation of the merger and upon request from Helix that we enter into limited forward sales of our production in instances when both we and Helix believe that such sales are reasonably prudent to Helix s acquisition economics and our expected economics.

Our actual drilling results may differ from our estimates of proved reserves.

Our estimates of the quantities of proved reserves and our projections of both future production rates and the timing of development expenditures are uncertain. Any downward revisions of these estimates could adversely affect our financial condition and could reduce our borrowing base under our credit facility.

Netherland, Sewell & Associates, Inc., our independent reservoir engineers, audit our estimate of our reserves. The accuracy of these reserve estimates depends in large part on the quality of available data and on the engineering and geological interpretation of reservoir engineers. Because they are estimates, they are subject to revision based on the results of actual drilling, testing, and production and will often differ from the quantities of oil and gas we ultimately recover.

Further, the estimate of our future net cash flows contained in our reserve report depends upon numerous assumptions including the amount of the reserves actually produced, the cost and timing of producing those reserves, and the price received for the production. To the extent these assumptions prove inaccurate, material changes to our estimates of our future net cash flows and our reserves could results.

We are dependent on other operators who influence our productivity.

We have limited influence over operations, including limited control over the maintenance of both safety and environmental standards, on properties we do not operate. The operators of those properties may, depending on the terms of the applicable joint operating agreement:

- refuse to initiate exploration or development projects;
- initiate exploration or development projects on a slower or faster schedule than we prefer; and/or
- drill more wells or build more facilities on a project than we can afford, whether on a cash basis or through financing, which may limit our participation in those projects or limit the percentage of our revenues from those projects.

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The occurrence of any of the foregoing events could have a material adverse effect on our anticipated exploration and development activities.

Adverse changes in the financial condition of our joint interest partners due to price declines, industry conditions, or events specific to a partner may affect our ability to carry out our program.

Some of our working interest owners may experience liquidity and cash flow problems caused by, among other things, a decline in oil and gas prices. These problems may lead to their attempting to delay the pace of drilling or development in order to conserve cash. Any such delay may be detrimental to our projects and the planned timing thereof.

The oil and gas industry is highly competitive.

Our quest to discover additional oil and gas reserves and acquire additional properties occurs in competition with some of the largest oil and gas companies in the world. These companies may be able to devote significantly greater financial resources to exploration and production projects and federal lease sales than we can. Moreover, if these companies operate projects in which we are joint interest owners, they may propose exploration and development programs in which we may not be able to participate due to financial constraints. This could cause us to lose our interest, at least for a time, in a particular lease or project. In addition, we compete with these companies in the hiring and retention of talented technical employees.

Government regulation may affect our ability to conduct operations, and the nature of our business exposes us to environmental liability.

Numerous federal and state regulations affect our oil and gas operations. Current regulations are constantly reviewed by the various agencies at the same time that new regulations are being considered and implemented. In addition, because we hold federal leases, the federal government requires us to comply with numerous additional regulations that focus on government contractors. The regulatory burden upon the oil and gas industry increases the cost of doing business and consequently affects our profitability.

Our oil and gas operations are subject to stringent federal, state, and local environmental laws and regulations. Environmental laws and regulations are complex, change frequently, and have tended to become more stringent over time. Many environmental laws require permits from governmental authorities before construction on a project may commence or before wastes or other materials may be discharged into the environment. The process for obtaining necessary permits can be lengthy and complex, and can sometimes result in the establishment of permit conditions that make the project or activity for which the permit was sought either unprofitable or otherwise unattractive. Even where permits are not required, compliance with environmental laws and regulations can require significant capital and operating expenditures, and we may be required to incur costs to remediate contamination from past releases of wastes into the environment. Failure to comply with these statues, rules and regulations may result in the assessment of administrative, civil and even criminal penalties. The most significant environmental obligations applicable to our operations relate to compliance with the federal Oil Pollution Act and the Clean Water Act. The Oil Pollution Act and its implementing regulations (OPA) establish requirements for the prevention of oil spills and impose liability for damages resulting from spills into waters of the United States. OPA also requires operators of offshore oil production facilities, such as our facilities in the Gulf of Mexico, to demonstrate to the U.S. Minerals Management Service that they possess at least $35.0 million in financial resources that are available to pay for costs that may be incurred in responding to an oil spill. The Clean Water Act and its implementing regulations impose restrictions and strict controls on the discharge of wastes typically generated by the oil and gas industry. The cost of compliance with this federal and state legislation could have a significant impact on our financial ability to carry out our oil and gas operations.

Our operations create the risk of environmental liabilities. We may incur liability to governments or to third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil or water. We could potentially discharge oil and gas into the environment in any of the following ways:

- from a well or drilling equipment at a drill site;
- from a leak in storage tanks, pipelines or other gathering and transportation facilities;

from damage to oil and gas wells resulting from accidents during otherwise normal operations; and

from blowouts, cratering or explosions.

Environmental discharges may move through the soil to water supplies or to adjoining properties, giving rise to additional liabilities. Some laws and regulations could result in liability for failure to obtain the proper permits for, to control the use of, or to notify the proper authorities of a hazardous discharge. Such liability could substantially reduce our net income and could cause us to suspend operations.

Our operations are also subject to environmental laws and regulations that impose requirements for remediation of soil and groundwater contamination. In many cases, these laws apply retroactively to previous waste disposal practices regardless of fault, legality of the original activities, or ownership or control of sites. A company could be subject to severe fines and cleanup costs of found liable under these laws. We own and operate properties previously owned and operated by companies whose waste disposal practices may have resulted in on-site contamination that may require remedial action under current standards. We may be required to undertake remedial actions for contamination in those properties.

Our business exposes us to casualty risks above our insurance coverage.

Our offshore and onshore operations are subject to inherent casualty risks such as fines, blowouts, cratering and explosions. Other risks include pollution, the uncontrollable discharge of oil, gas, brine or well fluids, and hazards of marine and helicopter operations such as capsizing, collision, and adverse weather and sea conditions. These risks may result in injury or loss of life, suspension of operations, environmental damage or property and equipment damage, all of which could cause us to experience substantial losses.

Our drilling operations involve risks from high pressures in the wells and from mechanical difficulties such as stuck pipes, collapsed casings and separated cables. Our offshore properties involve higher exploration and drilling risks that include the cost of constructing platforms and pipeline interconnections as well as weather delays and other risks.

Our insurance may not cover the full extent of all losses. This insurance coverage includes, among other things, comprehensive general liability, business interruption and limited coverage for sudden environmental damage. We do not believe that insurance that fully covers all environmental damage that occurs over time or all sudden environmental damage is available at a reasonable cost. The occurrence of an event that is not fully covered by insurance could materially increase our operating expenses and decrease our net income.

We undertake significant operational risks connected with our business.

Our drilling activities involve risks, such as drilling non-productive wells or dry holes, which are beyond our control. Often, the cost of drilling and operating wells and of installing production facilities is uncertain. Cost overruns are common risks that sometimes make a project uneconomical. The decision to purchase and exploit a prospect property depends on the evaluations of our operations staff. We may also decide to reduce or cease our drilling operations due to title problems, weather conditions, noncompliance with governmental requirements or shortages and delays in the delivery or availability of equipment or fabrication yards.

Another risk of our operations is the difficulty in marketing our oil and gas production. The proximity of our reserves to pipelines and the available capacity of pipelines and other transportation, processing and refining facilities also affect the marketing efforts. Even if we discover hydrocarbons in commercial quantities, a substantial period of time may elapse before we begin commercial production. If pipeline facilities in an area are insufficient, we may have to arrange for, and possibly bear the cost of, the construction or expansion of pipeline capacity before our production from that area can be marketed. Furthermore, if any of the major facilities into which we deliver our product become non-operational for any reason, our revenues will decline.

Item 1B. ***Unresolved Staff Comments***

None.

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Item 2. *Properties.*

We concentrate our principal operations in the federal waters of the Gulf of Mexico and its coastal regions. In addition to the information below, we encourage you to read the discussion in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements and the notes to our consolidated financial statements in Item 8, Financial Statements and Supplementary Data, below. Note 2 Oil and Gas Properties and Note 11 Oil and Gas Reserves and Present Value Disclosures in our Notes to Consolidated Financial Statements provide detailed information concerning costs incurred, proved oil and gas reserves, and discounted future net revenue for proved reserves.

Leasehold Acreage

Our leasehold acreage of oil and gas property as of December 31, 2005, was as follows:

	Undeveloped		**Developed**	
	Gross	**Net**	**Gross**	**Net**
Offshore	559,945	356,045	286,575	137,948
Onshore	14,700	11,622	26,034	8,730
Total	574,645	367,667	312,609	146,678

The current terms of leases on undeveloped acreage are scheduled to expire as shown in the table below. The term of a lease may be extended by drilling and production operations.

	For the Years Ended December 31,									
	2006		**2007**		**2008**		**2009 & Beyond**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Offshore	83,066	44,396	83,515	43,542	99,908	54,471	293,456	213,636	559,945	356,045
Onshore	5,230	4,666	3,708	2,490	4,292	2,996	1,470	1,470	14,700	11,622
Total	88,296	49,062	87,223	46,032	104,200	57,467	294,926	215,106	574,645	367,667

Proved Oil and Gas Reserves

Net proved oil and gas reserves at December 31, 2005, as audited by independent reserve engineers, Netherland, Sewell & Associates, Inc., are summarized below. The quantities of proved oil and gas reserves discussed in this section include only the amounts which we reasonably expect to recover in the future from known oil and gas reservoirs under the current economic and operating conditions. Proved reserves include only quantities that we expect to recover commercially using current prices, costs, existing regulatory practices, and technology. Therefore, any changes in future prices, costs, regulations, technology or other unforeseen factors could materially increase or decrease the proved reserve estimates.

	Net Oil Reserves MBbls	Net Gas Reserves MMcf
Offshore Gulf of Mexico	14,562	165,290
Onshore Gulf Coast	3,819	3,369
Total	18,381	168,659

In 2005, our standardized measure of discounted future net cash flows was $1.2 billion. We used the December 31, 2005, West Texas Intermediate posted price of $57.75 per barrel and Henry Hub spot market price of $10.08 per MMBtu, adjusted by property for energy content, quality, transportation fees, and regional price differentials. We estimated the costs based on the prior year costs incurred for individual properties or similar properties if a particular property did not produce during the prior year.

The present value of future net cash flows attributable to estimated net proved reserves, discounted at 10% per annum, (PV10) is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. The table below provides a reconciliation of PV10 to the standardized measure of discounted future net cash flows. PV10 may be considered a non-GAAP financial measure as defined by the SEC s Regulation G. We believe PV10 to be an important measure for evaluating the relative significance of our natural gas and oil operations. PV10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes. We further believe investors and creditors may utilize our PV10 as a basis for comparison of the relative size and value of our reserves to other companies. However, PV10 is not a substitute for the standardized measure. Our PV10 measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of our natural gas and oil reserves.

	At December 31,		
	2005	2004	2003
		(In thousands)	
Net present value of future cash flows, before income taxes	$ 1,768,285	$ 868,048	$ 651,829
Future income taxes, discounted at 10%	531,302	229,199	165,533
Standardized measure of discounted future net cash flows	$ 1,236,983	$ 638,849	$ 486,296

Producing Properties

The table below summarizes our ownership in producing wells at the end of each of the last three years.

	At December 31,					
	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Oil wells						
Offshore Gulf of Mexico	31	13.28	31	13.13	27	11.05
Onshore Gulf Coast	28	10.82	28	10.87	32	12.25
Total	59	24.10	59	24.00	59	23.30
Gas wells						
Offshore Gulf of Mexico	77	34.36	63	26.02	45	17.37
Onshore Gulf Coast	77	17.43	77	17.43	75	16.36
Total	154	51.79	140	43.45	120	33.73

Our offshore Gulf of Mexico properties account for approximately 85% of our oil production and approximately 98% of our gas production. In addition, total revenues from offshore Gulf of Mexico oil and gas production during 2005 accounted for approximately 95% of our total oil and gas revenues. We owned varying working interests (5% to 100%) in 162 offshore Gulf of Mexico blocks at December 31, 2005, and currently produce from 54 of these blocks. Three additional blocks are currently under development. We operate a majority of these blocks.

In addition, through our entry into 3-D seismic licensing agreements with various vendors, we have access to 3-D seismic data covering approximately 3,600 blocks in the Gulf of Mexico. The duration and coverage of the three most significant agreements are as follows:

Effective Date	**Duration**	**Approximate No. of Blocks Covered**
March, 1998	99 years	1,100
October, 2000	Indefinite	1,000
May, 2004	20 years with option to renew for 20 years	1,200

These agreements, combined with our computer technology, provide our technical team with immediate access to the seismic data covered by the agreements.

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During 2005, we successfully drilled 13 out of 19 exploratory wells and 4 out of 5 development wells in the offshore Gulf of Mexico. In addition, we constructed and installed 3 production platforms, 1 subsea wellhead, and 4 associated pipelines.

Our onshore Gulf Coast area properties are principally located in the State of Mississippi and along the Texas Gulf Coast. In 2005, these properties accounted for approximately 15% of our oil production and approximately 2% of our gas production. Our working interests in these wells range from 15% to 100%.

Drilling Activities

The following is a summary of our exploration and development wells drilled for the past three years.

	For the Years Ended December 31,											
	2005				2004				2003			
	Gross		Net		Gross		Net		Gross		Net	
	Prod.	Dry	Prod.	Dry	Prod.	Dry	Prod.	Dry	Prod.	Dry	Prod.	Dry
Exploratory												
Offshore Gulf of Mexico	13	6	8.87	4.65	17	7	9.28	4.15	15	7	8.00	3.46
Onshore Gulf Coast					0	1		0.20	2	1	0.41	1.00
Total	13	6	8.87	4.65	17	8	9.28	4.35	17	8	8.41	4.46
Development												
Offshore Gulf of Mexico	4	1	2.20	0.60	5	0	3.25		3	1	1.37	0.50
Onshore Gulf Coast					2	0	0.80	0.20	2	1	0.25	0.20
Total	4	1	2.20	0.60	7	0	4.05	0.20	5	2	1.62	0.70

We had an interest in 2 wells (1.50 net) in progress at December 31, 2005, 1 well (0.75 net) in progress at December 31, 2004, and 3 wells (2.10 net) in progress at December 31, 2003.

Other Property and Office Lease

We own several non-contiguous tracts of land covering approximately 2,500 surface acres in southern Louisiana and southern Mississippi. We currently lease approximately 19,000 square feet of office space in Dallas, Texas and have commitments to lease an additional 6,000 square feet in the same building in 2006. The lease on our office space expires in March 2012.

Item 3. ***Legal Proceedings.***

We are not a party to any material legal proceedings at this time.

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

We did not submit any matters to a vote of securityholders during the fourth quarter of 2005.

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PART II

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

Our common stock trades on the New York Stock Exchange under the symbol REM. The following table sets forth the high and low closing price per share for the periods indicated as reported in the NYSE composite transactions.

	Common Stock	
	High	**Low**
2006		
First Quarter through March 10, 2006	$ 44.80	$ 36.85
2005		
Fourth Quarter	40.98	31.16
Third Quarter	42.51	35.49
Second Quarter	36.36	27.71
First Quarter	34.49	24.82
2004		
Fourth Quarter	29.02	24.69
Third Quarter	26.27	21.45
Second Quarter	23.60	19.47
First Quarter	21.12	18.06

On March 10, 2006, the last reported sales price for our common stock was $41.41 per share. On that date, there were 443 stockholders of record.

No dividends have ever been paid on our common stock. Our credit facility agreement prohibits our paying dividends. The determination of future cash dividends, if any, will depend upon, among other things, our financial condition, cash flow from operating activities, the level of our capital and exploration expenditure needs, future business prospects, and renegotiation of our line of credit.

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The following table presents information about our equity compensation plans at December 31, 2005.

Plan category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance (c)
Equity compensation plans approved by stockholders	1,551,973	$ 6.13	976,413
Equity compensation plans not approved by stockholders	59,478	$	
Total	1,611,451	$ 5.91	976,413

The information above regarding equity compensation plans not approved by the stockholders includes contingent one-time stock grants made in 1999 to all employees and directors, which include the following significant attributes:

Shares awarded based on annual base salary as of June 17, 1999, or in the case of non-employee directors $100,000, divided by $4.19 (the closing price on June 17, 1999).

In order for the grants to become effective, our common stock had to close at or above $10.42 per share for 20 consecutive trading days within 5 years of the grant date (the trigger event).

The trigger event was achieved on January 24, 2001.

686,472 shares were awarded. As of December 31, 2005, 586,147 shares have vested, and 40,847 shares have been forfeited. The remaining 59,478 shares vested on January 17, 2006.

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

The selected consolidated financial data should be read in conjunction with our consolidated financial statements and notes to the consolidated financial statements. In addition, you should also read our Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 7 below.

	2005	2004	2003	2002	2001(1)
	(In thousands, except prices, volumes, and per-share data)				
Financial					
Total revenue	$ 270,529	$ 234,129	$ 183,052	$ 104,866	$ 116,620
Net income	$ 70,567	$ 60,996	$ 42,924	$ 11,332	$ 8,344
Basic income per share	$ 2.48	$ 2.23	$ 1.61	$ 0.45	$ 0.38
Diluted income per share	$ 2.37	$ 2.14	$ 1.53	$ 0.42	$ 0.35
Total assets	$ 586,065	$ 453,114	$ 359,385	$ 288,993	$ 240,432
Bank debt	$	$	$ 18,000	$ 37,400	$ 71,000
Stockholders equity	$ 404,159	$ 313,960	$ 241,877	$ 193,660	$ 125,338
Total shares outstanding	28,757	27,849	26,912	26,236	22,651
Cash Flow					
Net cash flow from operations	$ 160,819	$ 188,582	$ 153,215	$ 71,420	$ 99,025
Net cash flow (used in) investing	$ (189,906)	$ (148,908)	$ (115,714)	$ (92,126)	$ (119,242)
Net cash flow provided by (used in) financing	$ 9,288	$ (12,423)	$ (21,022)	$ 16,258	$ 21,463
Operational					
Proved reserves(2)					
Oil (MBbls)	18,381	16,899	11,619	13,114	13,865
Gas (MMcf)	168,659	150,699	142,432	124,967	111,920
Standardized measure of discounted future net cash flows end of year(2)	$ 1,236,983	$ 638,849	$ 486,296	$ 351,042	$ 199,983
Average sales price(3)					
Oil (per Bbl)	$ 51.24	$ 39.37	$ 29.43	$ 24.27	$ 23.29
Gas (per Mcf)	$ 8.31	$ 5.97	$ 5.40	$ 3.35	$ 4.02
Average production (net sales volume)					
Oil (Bbls per day)	4,066	4,588	4,863	4,736	3,378
Gas (Mcf per day)	60,715	76,869	66,160	47,804	58,265

(1) Financial results for 2001 include a $13.5 million charge for the final settlement of the Phillips Petroleum litigation.

(2) The quantities of proved oil and gas reserves include only the amounts which we reasonably expect to recover in the future from known oil and gas reservoirs under the current economic and operating conditions. Proved reserves include only quantities that we can commercially recover using current prices, costs, and existing regulatory practices and technology. We base the standardized measure of future discounted net cash flows on year-end prices and costs. Any changes in future prices, costs, regulations, technology, or other unforeseen

factors could significantly increase or decrease the proved reserve estimates.

(3) We have not entered into any financial hedges for oil or gas prices during any of the years presented, therefore, the average sales prices represent actual sales revenue per barrel or Mcf.

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

The following discussion will assist you in understanding our financial position, liquidity, and results of operations. The information below should be read in conjunction with our consolidated financial statements, and the notes to our consolidated financial statements. Our discussion contains both historical and forward-looking information. We assess the risks and uncertainties about our business, long-term strategy, and financial condition before we make any forward-looking statements, but we cannot guarantee that our assessment is accurate or that our goals and projections can or will be met. Statements concerning results of future exploration, exploitation, development, and acquisition expenditures as well as expense and reserve levels are forward-looking statements. We make assumptions about commodity prices, drilling results, production costs, administrative expenses, and interest costs that we believe are reasonable based on currently available information.

Critical Estimates and Accounting Policies

We prepare our consolidated financial statements in this report using accounting principles that are generally accepted in the United States (GAAP). GAAP represents a comprehensive set of accounting and disclosure rules and requirements. We must make judgments, estimates, and in certain circumstances, choices between acceptable GAAP alternatives as we apply these rules and requirements. The most critical estimate we make is the engineering estimate of proved oil and gas reserves. This estimate affects the application of the successful-efforts method of accounting, the calculation of depreciation, depletion, and amortization of oil and gas properties, and the estimate of the impairment of our oil and gas properties. It also affects the estimated lives used to determine asset retirement obligations. In addition, the estimates of proved oil and gas reserves are the basis for the related standardized measure of discounted future net cash flows.

Estimated Proved Oil and Gas Reserves

The evaluation of our oil and gas reserves is critical to the management of our operations and ultimately our economic success. Decisions such as whether development of a property should proceed and what technical methods are available for development are based on an evaluation of reserves. These oil and gas reserve quantities are also used as the basis for calculating the unit-of-production rates for depreciation, depletion, and amortization, evaluating impairment and estimating the life of our producing oil and gas properties in our asset retirement obligations. Our proved reserves are classified as either proved developed or proved undeveloped. Proved developed reserves are those reserves which can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves include reserves expected to be recovered from new wells from undrilled proven reservoirs or from existing wells where a significant major expenditure is required for completion and production. Since a significant amount of our drilling is ongoing exploration activity, our oil and gas reserve estimates in our year-end reports include significant proved undeveloped reserves because of new discoveries that are waiting for platform or pipeline facilities to be completed in order for production to commence. These proved undeveloped reserves are subject to higher uncertainty because the estimates for the reserves do not include any production history.

We prepare and independent reserve engineers audit the estimates of our oil and gas reserves presented in this report based on guidelines promulgated under GAAP and in accordance with the rules and regulations of the SEC. The audit of our reserves by the independent reserve engineers involves their rigorous examination of our technical evaluation and extrapolations of well information such as flow rates and reservoir pressure declines as well as other technical information and measurements. Our internal reservoir engineers interpret these data to determine the nature of the reservoir and ultimately the quantity of proved oil and gas reserves attributable to a specific property. Our proved reserves in this report include only quantities that we expect to recover commercially using current prices, costs, existing regulatory practices and technology. While we are reasonably certain that the proved reserves will be produced, the timing and ultimate recovery can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and changes in projections of long-term oil and gas prices. Revisions can include upward or downward changes in the previously estimated volumes of proved reserves for existing fields due to evaluation of (1) already available geologic, reservoir, or production data or (2) new geologic or reservoir data obtained from wells. Revisions can also include changes associated with significant changes in development strategy, oil and gas prices, or production equipment/facility capacity.

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Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows relies on these estimates of oil and gas reserves using commodity prices and costs at year-end. In our 2005 year-end reserve report we used the December 31, 2005, West Texas Intermediate posted price of $57.75 per barrel and Henry Hub spot market price of $10.08 per MMBtu adjusted by property for energy content, quality, transportation fees, and regional price differentials. We estimated the costs based on the prior year costs incurred for individual properties or similar properties if a particular property did not have production during the prior year. Future global economic and political events will most likely result in significant fluctuations in future oil prices.

Successful-Efforts Method of Accounting

Oil and gas exploration and production companies choose one of two acceptable accounting methods, successful-efforts or full cost. The most significant difference between the two methods relates to the accounting treatment of drilling costs for unsuccessful exploration wells (dry holes) and exploration costs. Under the successful-efforts method, we recognize exploration costs and dry hole costs (the primary uncertainty affecting this method) as expenses when incurred and capitalize the costs of successful exploration wells as oil and gas properties. Entities that follow the full cost method capitalize all drilling and exploration costs including dry hole costs into one pool of total oil and gas property costs.

It is typical for companies that drill a significant number of exploration wells, as we do, to incur dry hole costs. During the last three years we have drilled 69 exploration wells, of which 22 were considered dry holes resulting in a 68% success ratio on exploratory wells. It is impossible to accurately predict specific dry holes; however, based on past experience, we estimate that between 25% and 35% of our exploration wells and associated exploration drilling costs, will be dry holes. Because we cannot predict the timing and the magnitude of dry holes, quarterly and annual net income can vary dramatically.

The calculation of depreciation, depletion and amortization of capitalized costs under the successful-efforts method of accounting differs from that calculation under the full cost method in that the successful-efforts method requires us to calculate depreciation, depletion and amortization expense on individual properties rather than on one pool of costs. In addition, under the successful-efforts method, we asses our oil and gas properties individually for impairment compared to the assessment of one pool of costs under the full cost method.

Depreciation, Depletion and Amortization of Oil and Gas Properties

The application of the unit-of-production method of depreciation, depletion and amortization of oil and gas properties under the successful-efforts method of accounting is applied pursuant to the simple multiplication of units produced by the costs per unit associated with a property. The cost per unit is calculated by dividing the total costs associated with a property by the estimated proved oil and gas reserves on that property. The volumes or units produced and asset costs are known, and while the proved reserves have a high probability of recoverability, they are based on estimates that are subject to some variability. The factors which create this variability are included in the discussion of estimated proved oil and gas reserves above.

Impairment of Oil and Gas Properties

Like depreciation, depletion and amortization, we test for impairment of our oil and gas properties based on estimates of proved reserves. Proved oil and gas properties held and used by us are reviewed for impairment whenever events or circumstances indicate that the carrying amount may not be recoverable. We estimate the future undiscounted net cash flows of the affected properties to judge the recoverability of the carrying amounts. Initially this analysis is based on proved reserves. However, when we believe that a property contains oil and gas reserves that do not meet the defined parameters of proved reserves, an appropriately risk adjusted amount of these reserves may be included in the impairment evaluation. These reserves are subject to much greater risk of ultimate recovery. An asset would be impaired if the future undiscounted net cash flows were less than its carrying value. Impairments are measured by the amount by which the carrying value exceeds its fair value.

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Impairment analysis is performed on an ongoing basis. In addition to using estimates of oil and gas reserve volumes in conducting impairment analysis, it is also necessary to estimate future oil and gas prices. The impairment evaluation triggers include a significant long-term decrease in current and projected prices or reserve volumes, an accumulation of project costs significantly in excess of the amount originally expected, and historical and current negative operating losses. Although we evaluate future oil and gas prices as part of the impairment analysis, we do not view short-term decreases in prices, even if significant, as impairment triggering events.

Exploratory Drilling Costs

The costs of drilling an exploratory well are capitalized as uncompleted wells pending the determination of whether the well has found proved reserves. If proved reserves are not found, these capitalized costs are charged to expense. On the other hand, the determination that proved reserves have been found results in the continued capitalization of the drilling costs of the well and its reclassification as a well containing proved reserves. At times, it may be determined that an exploratory well may have found hydrocarbons at the time drilling is completed, but it may not be possible to classify the reserves at that time. In this case, we may continue to capitalize the drilling costs as an uncompleted well beyond one year when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project, or the reserves are deemed to be proved. At that time the well is either reclassified as a proved well or is considered impaired and its costs, net of any salvage value, are charged to expense.

Occasionally, we may choose to salvage a portion of an unsuccessful exploratory well in order to continue exploratory drilling in an effort to reach the target geological structure/formation. In such cases, we charge only the unusable portion of the well bore to dry hole expense, and we continue to capitalize the costs associated with the salvageable portion of the well bore and add the costs to the new exploratory well. In certain situations, the well bore may be carried for more than one year beyond the date drilling in the original well bore was suspended. This may be due to the need to obtain, and/or analyze the availability of, equipment or crews or other activities necessary to pursue the targeted reserves or evaluate new or reprocessed seismic and geographic data. If, after we analyze the new information and conclude that we will not reuse the well bore or if the new exploratory well is determined to be unsuccessful after we complete drilling, we will charge the capitalized costs to dry hole expense.

Asset Retirement Obligations

We adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, effective January 1, 2003. The statement requires that we estimate the fair value for our asset retirement obligations (dismantlement and abandonment of oil and gas wells and offshore platforms) in the periods the assets are first placed in service. We then adjust the current estimated obligation for estimated inflation and market risk contingencies to the projected settlement date of the liability. The result is then discounted to a present value from the projected settlement date to the date the asset was first placed in service. We record the present value of the asset retirement obligation as an additional property cost and as an asset retirement liability. We record a combination of the amortization of the additional property cost (using the unit-of-production method) and the accretion of the discounted liability as a component of our depreciation, depletion and amortization of oil and gas properties.

We base our initial liability on estimates of current costs to dismantle and abandon our existing platforms and wells on historical experience, industry practice, and external estimates of the cost to abandon similar platforms and wells subject to federal and state regulatory requirements. We increase the current liability estimate using a 3% annual inflation factor over the estimated productive life of the individual property and further increase the inflated liability by 5% for market cost risk. The liability is discounted using United States Treasury Securities with constant maturities that approximate the number of years of productive life for the property plus a 2.5% adjustment for credit risk. Revisions to the liability could occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding abandonment of wells.

Prior to our adoption of SFAS No. 143, we accrued an estimated dismantlement, restoration and abandonment liability using the unit-of-production method over the life of a property and included the accrued amount in

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depreciation, depletion and amortization expense. The total accrued liability ($5.5 million at December 31, 2002) was reflected as additional accumulated depreciation, depletion and amortization of oil and gas properties on our balance sheet.

In conformity with SFAS 143 we recorded the cumulative effect of this accounting change as of January 1, 2003, as if we had used this method in the prior years. At January 1, 2003, we increased our oil and gas properties by $9.0 million, recorded $11.8 million as an Asset Retirement Obligation liability and reduced our accumulated depreciation by $2.8 million ($5.5 million accrued dismantlement in prior years less accumulated depreciation, depletion and amortization of $2.7 million on the increased property costs). The adoption of the new standard had no material effect on our net income. The following pro forma data summarize our net income and net income per share for the year ended December 31, 2003, as if we had adopted the provisions of SFAS 143 on January 1, 2001, including aggregate pro forma asset retirement obligations on that date:

	Year Ended December 31, 2003 (In thousands, except per share amounts)	
Net income, as reported	$	42,924
Pro forma adjustment to reflect retroactive adoption of SFAS 143		34
Pro forma net income	$	42,958
Net income per share:		
Basic as reported	$	1.61
Basic pro forma	$	1.61
Diluted as reported	$	1.53
Diluted pro forma	$	1.53

3D Seismic Data License Agreements

The 3-D seismic agreements we have entered into allow us access to, but do not give us ownership of, 3-D seismic data. Prior to the 3-D seismic agreement we entered into in May of 2004, we had entered into two other significant 3-D seismic licensing agreements. The agreement entered into in 1998 covered approximately 1,100 blocks in the Gulf of Mexico and has a 99 year term while the agreement entered into in 2000 covers approximately 1,000 blocks in the Gulf of Mexico and is for an indefinite term.

Until the third quarter of 2003, our accounting policy was to capitalize a discounted total of the required payments under the agreements over an assumed useful life of four years using the straight line method. In the fourth quarter of 2003, we completed a review of our accounting policies in relation to the contracts and determined that as of the fourth quarter 2003, we would charge exploration expense as invoices are paid. This change did not have a material effect on our current or prior financial statements.

In May 2004, we entered into a 3-D seismic licensing agreement covering an additional approximately 1,200 blocks in deeper water trends in the Gulf of Mexico. The license has a term of 20 years with an option to renew for an additional 20 years. An initial payment followed by a series of quarterly invoices through July 2008 is provided for in the agreement. There are no contingent payments. The license agreement is an executory contract under which both parties have certain ongoing rights and obligations. If we wish to continue using the data, we are required to make the payments as invoiced and comply with certain confidentiality provisions. The vendor s ongoing obligations include warranty and indemnity responsibilities as to intellectual property matters. We believe that the contract provides us with termination rights and therefore under our accounting policy, we recognize the liabilities as they become due and payable within the terms of the contract. In the event of an enforceable finding that we do not have a right of termination prior to the full contract price being due and payable, we would re-assess our accounting policy with respect to this agreement.

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General and Administrative Expenses

Our general and administrative expenses are affected by the method in which we measure and record stock based compensation expense and, to a lesser extent, assumptions related to our defined benefit pension plans. We have included a further discussion of these critical estimates and accounting policies in the following sections of this item: Long-Term Strategy and Business Developments, Liquidity and Capital Resources and Results of Operations. Our Notes to Consolidated Financial Statements included in this report also have a more comprehensive discussion of our significant accounting policies.

New Accounting Pronouncements

In April 2005, the FASB issued Staff Position No. FAS 19-1, Accounting for Suspended Well Costs, (FSP 19-1). FSP 19-1 amends SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, (SFAS 19) to allow continued capitalization of exploratory well costs beyond one year from the completion of drilling under circumstances where the wells have found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. FSP 19-1 also amends SFAS 19 to require enhanced disclosures of suspended exploratory well costs in the notes to the financial statements for annual and interim periods when there has been a significant change from the previous disclosure. The guidance in FSP 19-1 was effective for the first reporting period beginning after April 4, 2005. Accordingly, we adopted the new requirements and have included the required disclosures in footnote 1. The adoption of FSP 19-1 did not impact our financial position or results of operations.

In December 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payment (SFAS 123R), which is a revision of Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation (SFAS 123). SFAS 123R supersedes Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees (APB 25) and amends Statement of Financial Accounting Standards No. 95, Statement of Cash Flows . Generally, the approach in SFAS 123R is similar to the approach described in SFAS 123. However, SFAS 123R will require all share-based payments to employees, including grants of employee stock options, to be recognized in our Consolidated Statements of Income based on their fair values. Pro forma disclosure is no longer an alternative. SFAS 123R must be adopted no later than January 1, 2006 and permits us to adopt its requirements using one of two methods:

A modified prospective method in which compensation cost is recognized beginning with the effective date based on the requirements of SFAS 123R for all share-based payments granted after the effective date and based on the requirements of SFAS 123 for all awards granted to employees prior to the adoption date of SFAS 123R that remain unvested on the adoption date.

A modified retrospective method which includes the requirements of the modified prospective method described above, but also permits entities to restate either all prior periods presented or prior interim periods of the year of adoption based on the amounts previously recognized under SFAS 123 for purposes of pro forma disclosures.

We have elected to adopt the provisions of SFAS 123R on January 1, 2006, using the modified prospective method. As permitted by SFAS 123, we currently account for share-based payments to employees using the intrinsic value method prescribed by APB 25 and related interpretations. Therefore, we do not recognize compensation expenses associated with employee stock options. Currently, since all of our outstanding stock options have vested prior to the adoption of SFAS 123R, we will not recognize any expenses associated with these prior stock option grants. However, the adoption of SFAS 123R fair value method could have a significant impact on our future results of operations for future stock or stock option grants but no impact on our overall financial position. Had we adopted SFAS 123R in prior periods, the impact would have approximated the impact of SFAS 123 as described in the pro forma net income and income per share disclosures in Notes to Consolidated Financial Statements, Note 1 Summary of Significant Accounting Policies Stock Options. The adoption of SFAS 123R will have no effect on our outstanding stock grant awards.

SFAS 123R also requires the tax benefits of tax deductions in excess of recognized compensation expenses to be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement may reduce our future cash provided by operating activities and increase future cash provided by financing activities, to the extent of associated tax benefits that may be realized in the future. While we cannot estimate what those amounts will be in the future (because they depend on, among other things, when employees exercise stock options), the amount of operating cash flows from such excess tax deductions was $5.4 million during the year ended December 31, 2005.

In March 2005, the FASB issued FASB Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations. The interpretation clarifies the requirement to record abandonment liabilities stemming from legal obligations when the retirement depends on a conditional future event. FIN No. 47 requires that the uncertainty about the timing or method of settlement of a conditional retirement obligation be factored into the measurement of the liability when sufficient information exists. We adopted FIN No. 47 as of December 31, 2005. There was no material impact on our results of operations, financial condition, or cash flows.

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154, Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statements No. 3 (SFAS 154). SFAS 154 requires retrospective application to prior period financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS 154 will become effective on January 1, 2006. The impact of SFAS 154 will depend on the nature and extent of any voluntary accounting changes and correction of errors after the effective date, but we do not currently expect SFAS 154 to have a material impact on our results of operations, financial condition, or cash flows.

Long-Term Strategy and Business Developments

Our long-term strategy is to increase our oil and gas reserves and production while keeping our finding and development costs and operating costs (on a per Mcf equivalent (Mcfe) basis) competitive with our industry peers. We will implement this strategy through drilling exploratory and development wells from our inventory of available prospects that we have evaluated for geologic and mechanical risk and future reserve potential. Our drilling program will contain some high risk/high reserve potential opportunities as well as some lower risk/lower reserve potential opportunities, in order to attempt to achieve a balanced program of reserve and production growth. Success of this strategy is contingent on various risk factors, as discussed in our filings with the SEC. Over the last three years, we have invested $492.9 million in oil and gas properties and found 179.8 Bcfe of proved reserves. The following tables reflect our results during the last three years.

	2005	**% Increase (Decrease)**	**2004**	**% Increase (Decrease)**	**2003**
Production:					
Oil MBbls	1,484	(11)%	1,675	(6)%	1,775
Gas MMcf	22,161	(21)%	28,057	16%	24,149
Total MMcfe(1)	31,065	(18)%	38,107	9%	34,799
Proved reserves:					

Oil MBbls	18,381	9%	16,899	45%	11,619
Gas MMcf	168,659	12%	150,699	6%	142,432
Total MMcfe(1)	278,945	11%	252,093	19%	212,146
Operating costs per Mcfe	$ 0.90	36%	$ 0.66	10%	$ 0.60

(1) Barrels of oil are converted to Mcfe at the ratio of 1 barrel of oil equals 6 Mcf of gas.

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Operating costs on a Mcfe produced basis have increased over the past three years from $0.60 to $0.90 or approximately 50% (or 25% per annum). This is the result of rising material and labor costs experienced during a period of increasing activity in our sphere of operations.

	For the Years Ended December 31, 2005	2004	2003	Three Years Ended December 31, 2005
		(In thousands)		
Unproved acquisition costs	$ 8,985	$ 10,878	$ 2,370	$ 22,233
Proved acquisition costs	3,024	1,554	1,466	6,044
Exploration	111,427	80,970	54,138	246,535
Development	94,525	65,080	58,475	218,080
Asset retirement obligation	2,770	4,267	9,963	17,000
Total capital and exploration costs	$ 220,731	$ 162,749	$ 126,412	$ 509,892
Proved reserves (Mcfe)				
Beginning total proved reserves	252,093	212,146	203,651	203,651
Revisions of previous estimates	(6,360)	(1,629)	(7,932)	(15,921)
Extensions, discoveries and other	64,809	79,683	44,698	189,190
Reserves purchased			6,528	6,528
Total proved reserve additions	58,449	78,054	43,294	179,797
Reserves sold	(532)			(532)
Production	(31,065)	(38,107)	(34,799)	(103,971)
Ending total proved reserves	278,945	252,093	212,146	278,945

The implementation of our long-term strategy requires that we continually incur significant capital expenditures in order to replace current production and find and develop new oil and gas reserves. In order to finance our capital and exploration program, we depend on cash flow from operations or bank debt and equity offerings as discussed below in Liquidity and Capital Resources.

Liquidity and Capital Resources

Cash flow provided by operations for the year ended December 31, 2005, decreased by $27.8 million, or 14.7%, compared to the prior year primarily due to increases in working capital accounts in addition to a 18.5% decrease in production offset partially by a $2.25/Mcfe, or 36.7% increase in oil and gas prices. The decrease in our production during 2005 compared to 2004 was primarily the direct result of Hurricanes Katrina and Rita which shut-in much of our production for the entire fourth quarter of 2005. We expect our cash flow provided by operations for 2006 to increase because of higher projected production from new properties, combined with oil and gas prices consistent with 2005, and steady operating, general and administrative, interest and financing costs per Mcfe.

Excluding the effects of significant unforeseen expenses or other income, our cash flow from operations fluctuates primarily because of variations in oil and gas production and prices or changes in working capital accounts. Our oil and gas production will vary based on actual well performance but may be curtailed due to factors beyond our control. Hurricanes in the Gulf of Mexico will shut down our production for the duration of the storm s presence in the Gulf, and may damage our production facilities so that we cannot produce from a particular property for an extended amount of time. In addition, downstream activities on major pipelines in the Gulf of Mexico can also cause us to shut-in production for various lengths of time, as was exemplified by pipeline and other infrastructure disruptions caused by Hurricanes Katrina and Rita in 2005. Further, Hurricane Rita destroyed two third party drill rigs working under contract on two of our exploration wells. The loss of the two drill rigs caused us to push our drilling plans into the future at a slower pace. Due to the limited availability of drill rigs, the rate of finding and developing new oil and gas reserves in the Gulf of Mexico may be slower.

Our realized oil and gas prices vary significantly due to world political events, supply and demand of products, production storage levels, and weather patterns. We sell the vast majority of our production at spot market prices. Accordingly, product price volatility will affect our cash flow from operations. To mitigate price volatility we sometimes lock in prices for some portion of our production (usually less than 33%) through the use of forward sale agreements. See additional discussion under Commodity Price Risk in Item 7A Quantitative and Qualitative Disclosures about Market Risk.

Changes in our working capital accounts from 2004 to 2005 include an increase in our accounts receivable (a decrease in our cash flow provided by operations) due to increased balances due from our joint interest participants as a result of increased operating activities (drilling wells and facilities construction) at year end and from hurricane related insurance receivables and income tax receivables. In addition, accounts payable decreased by $15.3 million which decreased our cash flow from operations.

On January 22, 2006, we entered into a merger agreement with Helix Energy Solutions Group, Inc. (formerly Cal Dive International Inc.). Consideration for the offer from Helix will be $27.00 in cash and 0.436 shares of Helix stock for each of our shares. Completion of the merger is subject to customary conditions to closing, including without limitation, approval by our stockholders. Under the terms of the merger agreement, we may be required to pay Helix the sum of (i) Helix s documented out of pocket fees and expenses incurred or paid by or on behalf of Helix in connection with the merger or the consummation of any of the transactions contemplated by the merger agreement, including all regulatory filing fees, fees and expenses of counsel, commercial banks, investment banking firms, accountants, experts, environmental consultants, and other consultants to Helix, up to a maximum amount not to exceed $2 million, and (ii) $45 million if the merger agreement is terminated under certain circumstances and we enter into or complete an alternative transaction. We believe that with our credit facility and other financial resources that we will be able to make such payments if required.

We incurred capital and exploration expenditures totaling $220.7 million during 2005. The capital expenditures included $12.0 million for leasehold acquisition, $111.4 million for exploration costs, $94.5 million for development costs, including platform and facilities construction and $2.8 million for asset retirement costs. During the year, we built and installed 6 offshore platforms and facilities. In addition, in 2005 we drilled 19 offshore exploration wells and 5 offshore development wells and had 2 wells in progress at year end.

We expect to continue to make significant capital expenditures over the next several years as part of our long-term growth strategy. We have budgeted $293 million for capital and exploration expenditures in 2006. Our 2006 capital and exploration budget includes $146 million for 28 exploratory wells. We project that we will spend $141 million on 26 wells in the Gulf of Mexico and $5 million on 2 onshore wells in Mississippi. The budget also includes $112 million for platforms and development drilling. Additional development expenditures beyond the budgeted amount will be required throughout the year; the amount of such additional expenditures being dependent upon our success with our 2006 exploration and development program. The remaining $35 million will be allocated to leasehold acquisitions, seismic acquisitions, and workovers. If our exploratory drilling results in significant new discoveries, we will have to expend additional capital in order to finance the completion, development, and potential additional opportunities generated by our success. We believe that, because of the additional reserves resulting from the exploratory success and our record of reserve growth in recent years, we will be able to access sufficient additional capital through available cash on hand and/or additional bank financing and/or offerings of debt or equity securities.

On September 9, 2005, we increased our credit facility from $150 million to $200 million and the associated borrowing base from $100 million to $150 million. Interest only is payable quarterly through September 2009, at which time the line expires and all principle becomes due, unless the line is extended or renegotiated. As of December 31, 2005, there were no borrowings outstanding under this facility. The most significant financial covenants in the line of credit include, among others, maintaining a minimum current ratio (as defined in the facility agreement) of 1.0 to 1.0, a minimum tangible net worth of $175 million plus 50% of net income (accumulated from the closing date of the facility agreement) and 75% of the net proceeds of any corporate equity offering, and interest coverage of 2.5 to 1.0. We are currently in compliance with these financial covenants. If we do not comply with these covenants, the lenders have the right to refuse to advance additional funds under the facility and/or declare all principle and interest immediately due and payable. The merger agreement prohibits us from incurring more than $50 million in debt under the credit facility pending consummation of the transaction.

On June 19, 2003, we filed a shelf registration statement to issue up to $200.0 million of common stock, debt securities, preferred stock, and of warrants. The SEC declared the shelf registration statement effective December 18, 2003. We have not drawn on the shelf offering.

The following table summarizes our contractual obligations and commercial commitments as of December 31, 2005.

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
	(In thousands)				
Contractual obligations					
Bank debt (commitment fees)	1,384	375	750	259	
Other(1)	7,940	3,000	4,940		
Office lease	4,220	644	1,350	1,366	860
Total	13,544	4,019	7,040	1,625	860

(1) Other includes scheduled payments pursuant to 3-D seismic license agreement.

On December 31, 2005, our current assets exceeded our current liabilities by $62.6 million. Our current ratio was 1.81 to 1.00.

Results of Operations

In 2005, we achieved net income totaling $70.6 million or $2.48 basic income per share, and $2.37 diluted income per share, compared to a net income of $61.0 million or $2.23 basic income per share and $2.14 diluted income per share in 2004. The increase in net income resulted primarily from increased oil and gas sales prices offset partially by a decrease in oil and gas production. During the third quarter of 2005, damage to our production platforms and pipelines, as well as third party pipelines and facilities, caused us to lose a significant amount of our production during the fourth quarter of 2005. In addition to oil and gas sales prices and production, certain accounting policies discussed below can cause our net income to vary significantly from period to period because of events or circumstances which trigger recognition of expenses for unsuccessful wells or impairments of properties. Further, we calculate certain expenses using estimates of oil and gas reserves that can vary significantly.

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Oil and Gas Sales Revenue

The following table discloses the net oil and gas production volumes, sales, and sales prices for each of the three years ended December 31, 2005, 2004, and 2003.

	2005	% Increase (Decrease)	2004	% Increase (Decrease)	2003
	(Revenue information in thousands)				
Oil volume (MBbls)	1,484	(11)%	1,675	(6)%	1,775
Oil revenue	$ 76,039	15%	$ 65,941	26%	$ 52,233
Price per Bbl	$ 51.24	30%	$ 39.37	34%	$ 29.43
Increase in oil sales revenue due to:					
Change in prices	$ 19,882		$ 17,644		
Change in production volume	(9,784)		(3,936)		
Total increase in oil revenue	$ 10,098		$ 13,708		
Gas volume (MMcf)	22,161	(21)%	28,057	16%	24,149
Gas revenue	$ 184,095	10%	$ 167,564	29%	$ 130,346
Price per Mcf	$ 8.31	39%	$ 5.97	11%	$ 5.40
Increase (decrease) in gas revenue due to:					
Change in prices	$ 65,653		$ 13,765		
Change in production volume	(49,122)		$ 23,453		
Total increase in gas revenue	$ 16,531		$ 37,218		

Oil sales revenue during 2005 increased by $10.1 million, or 15%, compared to 2004 because average oil prices increased by $11.87 per barrel, or 30%, which more than offset a 191,000 barrel (11%) decline in oil production. During 2004, oil sales revenue increased by $13.7 million, or 26%, compared to 2003 because average oil prices increased by $9.94 per barrel, or 34%, which more than offset a 100,000 barrel (6%) decline in oil production.

Gas sales revenue during 2005 increased by $16.5 million, or 10%, compared to 2004 because average gas prices increased by $2.34 per mcf, or 39%, which more than offset a decrease in production of 5,897 Mmcf, or (21)%. During 2004, gas sales revenue increased by $37.2 million, or 29% because of higher average gas prices and production. Average gas prices climbed from $5.40 per Mcf in 2003 to $5.97 per Mcf, or 11%, in 2004. Production increased by 3.9 Bcf, or 16%, primarily because of gas production from new properties in the offshore Gulf of Mexico.

Operating Costs and Expenses

Total operating costs during 2005 increased by $3.1 million, or 12.2%, compared to 2004, due to the increase in the number of operating properties. However, operating costs per Mcfe increased by $0.24, or 36.4%, to $0.90 during 2005 due to the decrease in production. The following table presents the major components of our operating costs and operating costs per Mcfe.

	Years Ending December 31,					
	2005		2004		2003	
	Total	Per Mcfe	Total	Per Mcfe	Total	Per Mcfe
	(In thousands, except per Mcfe amounts)					
Direct operating expense	$ 19,969	$ 0.64	$ 18,406	$ 0.49	$ 15,709	$ 0.45
Overhead & company labor	811	0.03	536	0.01	346	0.01
Workovers	4,383	0.14	2,525	0.07	1,597	0.04
Ad-valorem taxes	130	0.00	34	0.00	74	0.00
Production taxes	755	0.02	871	0.02	870	0.03
Transportation	2,021	0.07	2,641	0.07	2,314	0.07
Total	$ 28,069	$ 0.90	$ 25,013	$ 0.66	$ 20,910	$ 0.60

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Exploration Expenses Successful-Efforts Method of Accounting

During 2005, exploration expenses increased by $32.7 million, or 145.1%, compared to 2004 primarily because of a $35.9 million (280.6%) increase in dry hole costs. Dry hole costs for 2005 include the South Pass 87 Aquarius well at a total cost of $22.7 million. Exploration expenses for 2004 decreased by $2.9 million, or 11%, because of an $11.2 million (46.7%) decrease in dry hole costs. During the last three years we have drilled 69 exploration wells, of which 22 were considered dry holes, resulting in a 68% success ratio on exploratory wells. Our dry hole costs charged to expense during this period totaled $48.7 million out of total exploratory drilling costs of $104.8 million.

Depreciation, Depletion, and Amortization of Oil and Gas Properties

We calculate depreciation, depletion, and amortization expense (DD&A) using the estimates of proved oil and gas reserves. We segregate the costs for individual or contiguous properties or projects and record DD&A of these property costs separately using the units-of-production method. Downward revisions in reserves increase the DD&A per unit and reduce our net income; likewise, upward revisions lower the DD&A per unit and increase our net income. Depreciation, depletion and amortization expense recorded in 2005 decreased by $12.5 million, or 17.1%, compared to the prior year. On a per Mcfe basis, depreciation, depletion and amortization per Mcfe increased to $1.94 in 2005 from $1.91 in 2004 reflecting the increased costs for finding reserves in the Gulf of Mexico. Depreciation, depletion and amortization expense increased by $17.1 million, or 31% for the year ended December 31, 2004, compared to the prior year, and depreciation, depletion and amortization per Mcfe increased to $1.91 from $1.60 in 2003 reflecting the increased costs for finding reserves in the Gulf of Mexico.

Impairment of Oil and Gas Properties

Because we account for our proved oil and gas properties separately, we also assess our assets for impairment property by property rather than in one pool of total oil and gas property costs. This method of assessment is another feature of the successful-efforts method of accounting. Certain unforeseeable events such as significantly decreased long-term oil or gas prices, failure of a well or wells to perform as projected, insufficient data on reservoir performance, and/or unexpected or increased costs may cause us to record an impairment expense on a particular property. We base our assessment of possible impairment using our best estimate of future prices, costs and expected net cash flow generated by a property. We estimate future prices based on NYMEX 12 month strips, adjusted for basis differential and escalate both the prices and the costs for inflation if appropriate. If these estimates indicate impairment, we measure the impairment expense as the difference between the net book value of the asset and its estimated fair value measured by discounting the future net cash flow from the property at an appropriate rate. Actual prices, costs, discount rates, and net cash flow may vary from our estimates. We recognized impairment expenses during the last three years as follows:

	For the Years Ended December 31,		
	2005	**2004**	**2003**
		(In thousands)	
Unproved properties	$ 1,238	$ 1,130	$ 1,136
Proved properties		9,746	3,311
Other	245		
Total impairment expense	$ 1,483	$ 10,876	$ 4,447

We estimate the amount of individually insignificant unproved properties which will prove unproductive by amortizing the balance of our individual immaterial unproved property costs (adjusted by an anticipated rate of future successful development) over an average lease term. Individually significant properties will continue to be evaluated periodically on a separate basis for impairment. We will transfer the original cost of an unproved property to proved properties when we find commercial oil and gas reserves sufficient to justify full development of the property. The impairment of unproved properties for the prior two years resulted from the actual (due to unsuccessful exploration results) or impending forfeiture of leaseholds.

We analyze our proved properties for impairment indicators based on the proved reserves as determined by our internal reserve engineers. No proved properties were impaired during 2005. The properties impaired in 2004

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primarily consisted of two properties in the Gulf of Mexico which totaled $4.2 million and two onshore Gulf Coast properties which totaled $5.5 million. During 2003, we impaired two properties in the Gulf of Mexico which totaled $2.4 million and one property in the onshore Gulf Coast which totaled $855,000. The impairments resulted primarily from wells depleting sooner than originally estimated or capital costs in excess of those anticipated.

General and Administrative

General and administrative expenses during 2005 increased by $7.1 million, or 88.5% compared to 2004. General and administrative expenses increased by $0.28 per Mcfe to $0.49 in 2005 from $0.21 in 2004. General and administrative expenses in 2004 decreased by $355,000. Stock based compensation expense which is included in general and administrative expense totaled $4.6 million in 2005, $1.4 million in 2004 and $1.6 million in 2003.

Interest and Financing Expense

Interest and financing expense decreased during the past two years because of lower interest rates and lower outstanding debt.

Income Taxes

During 2005, income taxes increased by $6.1 million compared to 2004 and increased by $9.3 million during 2004 compared to 2003 as a result of increased income before taxes. The effective tax rate increased slightly in 2005 due to an increase in the provision for deferred state income taxes.

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

Commodity Price Risk

A vast majority of our production is sold on the spot markets. Accordingly, we are at risk for the volatility of commodity prices inherent in the oil and gas industry.

Occasionally we sell forward portions of our production under physical delivery contracts that by their terms cannot be settled in cash or other financial instruments. Such contracts are not subject to the provisions of Statement of Financial Accounting Standards No. 133 Accounting for Derivative Instruments and Hedging Activities. Accordingly, we do not provide sensitivity analysis for such contracts. Subsequent to year end, we entered into physical delivery contracts for the period March 2006 through June 2007 as follows:

Oil:	1,000 bbls/day @ $70.00/bbl	March 2006 February 2007
Gas:	20 mmbtu/day @ $9.83/mmbtu	March 2006 August 2006
	10 mmbtu/day @ $8.88/mmbtu	September 2006 December 2006
	20 mmbtu/day @ $9.72/mmbtu	January 2007 June 2007

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

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
Remington Oil and Gas Corporation:

We have audited the accompanying consolidated balance sheets of Remington Oil and Gas Corporation and subsidiaries (the Company) as of December 31, 2005 and 2004, and the related consolidated statements of income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2005 and 2004, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 10, 2006 expressed an unqualified opinion thereon.

As discussed in Note 1 to the consolidated financial statements, in 2003 the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations.

/s/ Ernst & Young LLP

Dallas, Texas
March 10, 2006

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REMINGTON OIL AND GAS CORPORATION

CONSOLIDATED BALANCE SHEETS

	At December 31, 2005	2004
	(In thousands, except per share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 38,860	$ 58,659
Accounts receivable	66,887	49,582
Insurance receivable	23,308	
Income taxes receivable	5,767	
Prepaid expenses and other current assets	5,466	5,199
Total current assets	140,288	113,440
Properties		
Oil and gas properties (successful-efforts method)	908,437	744,215
Other properties	3,758	3,145
Accumulated depreciation, depletion and amortization	(468,290)	(409,591)
Total properties	443,905	337,769
Other assets		
Other assets	1,872	1,905
Total other assets	1,872	1,905
Total assets	$ 586,065	$ 453,114
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Accounts payable and accrued expenses	$ 76,561	$ 69,339
Current deferred income taxes	1,094	
Total current liabilities	77,655	69,339
Long-term liabilities		
Asset retirement obligations	21,375	16,030
Deferred income taxes	82,876	53,785
Total long-term liabilities	104,251	69,815
Total liabilities	181,906	139,154

Commitments and contingencies (Note 5)		
Stockholders equity		
Preferred stock, $0.01 par value, 25,000,000 shares authorized shares issued none		
Common stock, $.01 par value, 100,000,000 shares authorized, 28,790,997 shares issued and 28,756,638 shares outstanding in 2005, 27,883,698 shares issued and 27,849,339 shares outstanding in 2004	288	279
Additional paid-in capital	149,234	132,334
Restricted common stock	24,264	6,749
Unearned compensation	(20,385)	(5,593)
Retained earnings	250,758	180,191
Total stockholders equity	404,159	313,960
Total liabilities and stockholders equity	$ 586,065	$ 453,114

See accompanying Notes to Consolidated Financial Statements.

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REMINGTON OIL AND GAS CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2005	2004	2003
	(In thousands, except per-share amounts)		
Revenues and other income			
Gas sales	$ 184,095	$ 167,564	$ 130,346
Oil sales	76,039	65,941	52,233
Interest income	1,806	349	161
Other income	8,589	275	312
Total revenues and other income	270,529	234,129	183,052
Costs and expenses			
Operating costs and expenses	28,069	25,013	20,910
Exploration expenses	55,272	22,551	25,416
Depreciation, depletion, and amortization	60,351	72,810	55,694
Impairment of oil and gas properties	1,483	10,876	4,447
General and administrative	15,182	8,053	8,408
Interest and financing expense	613	894	1,635
Total costs and expenses	160,970	140,197	116,510
Income before taxes	109,559	93,932	66,542
Income taxes	38,992	32,936	23,618
Net income	$ 70,567	$ 60,996	$ 42,924
Basic income per share	$ 2.48	$ 2.23	$ 1.61
Diluted income per share	$ 2.37	$ 2.14	$ 1.53

See accompanying Notes to Consolidated Financial Statements.

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REMINGTON OIL AND GAS CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	Common Stock $0.01 Par Value	Additional Paid in Capital	Restricted Common Stock	Unearned Compensation	Treasury Stock	Retained Earnings
			(In thousands)			
Balance December 31, 2002	$ 263	$ 115,827	$ 5,468	$ (3,192)	$ (977)	$ 76,271
Net income						42,924
Amortization of unearned compensation				1,318		
Forfeit contingent stock grant shares			(206)	206		
Common stock issued	7	4,998	(2,106)		(808)	
Tax benefit from exercise of stock options		1,884				
Treasury stock retired	(1)	(1,784)			1,785	
Balance December 31, 2003	269	120,925	3,156	(1,668)		119,195
Net income						60,996
Amortization of unearned compensation				1,251		
Stock grant			5,176	(5,176)		
Common stock issued	11	7,970	(1,583)		(645)	
Tax benefit from exercise of stock options		4,083				
Treasury stock retired	(1)	(644)			645	
Balance December 31, 2004	279	132,334	6,749	(5,593)		180,191
Net income						70,567
Amortization of unearned compensation				4,639		
Stock grant			19,431	(19,431)		
Common stock issued	10	12,166	(1,916)		(691)	
Tax benefit from exercise of stock options		5,425				
Treasury stock retired	(1)	(691)			691	
Balance December 31, 2005	$ 288	$ 149,234	$ 24,264	$ (20,385)		$ 250,758

See accompanying Notes to Consolidated Financial Statements.

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REMINGTON OIL AND GAS CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2005	2004	2003
		(In thousands)	
Cash flow provided by operations			
Net income	$ 70,567	$ 60,996	$ 42,924
Adjustments to reconcile net income			
Depreciation, depletion, and amortization	60,351	72,810	55,694
Deferred income tax expense	30,185	25,034	23,443
Amortization of deferred finance charges	155	183	207
Impairment of oil and gas properties	1,483	10,876	4,447
Dry hole costs	48,666	12,787	23,993
Net settlement for dismantlement and restoration liability	645	(1,712)	(1,631)
Stock based compensation	4,639	1,427	1,565
Tax benefit from exercise of employee stock options	5,425	4,083	
Changes in working capital			
(Increase) in accounts receivable	(16,793)	(6,570)	(10,483)
(Increase) in insurance receivable	(23,308)		
(Increase) in income taxes receivable	(5,767)		
(Increase) decrease in prepaid expenses and other assets	(121)	(2,360)	2,313
Increase (decrease) in accounts payable and accrued expenses	(15,308)	11,028	10,743
Net cash flow provided by operations	160,819	188,582	153,215
Cash from investing activities			
Payments for capital expenditures	(189,906)	(148,908)	(115,714)
Net cash (used in) investing activities	(189,906)	(148,908)	(115,714)
Cash from financing activities			
Payments on other long-term payables		(18,000)	(22,573)
Treasury stock acquired and retired	(691)	(645)	(808)
Commitment fee on line of credit	(280)		(294)
Common stock issued	10,259	6,222	2,653
Net cash provided by (used in) financing activities	9,288	(12,423)	(21,022)
Net increase (decrease) in cash and cash equivalents	(19,799)	27,251	16,479
Cash and cash equivalents at beginning of period	58,659	31,408	14,929
Cash and cash equivalents at end of period	$ 38,860	$ 58,659	$ 31,408
Cash paid for interest	$ 436	$ 948	$ 1,702

Cash paid for taxes	$ 12,387	$ 580	$ 175

See accompanying Notes to Consolidated Financial Statements.

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Note 1 Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

Remington Oil and Gas Corporation is an independent oil and gas exploration and production company incorporated in Delaware. We have working interest ownership rights in properties in the offshore Gulf of Mexico and onshore Gulf Coast. We acquired the following subsidiaries in 1998: CKB Petroleum, Inc., CKB & Associates, Inc., Box Brothers Realty Investments Company, CB Farms, Inc., and Box Resources, Inc. We consolidate 100% of the assets, liabilities, equity, income and expense of the subsidiaries and eliminate all inter-company transactions and account balances for the periods of consolidation. We own 100% of the outstanding capital stock of all of the subsidiaries. The primary operating subsidiary, CKB Petroleum, Inc., owns an undivided interest in a pipeline that transports our oil from our South Pass blocks, offshore Gulf of Mexico, to Venice, Louisiana. We account for our undivided interests in properties using the proportionate consolidation method, whereby our share of assets, liabilities, revenues and expenses are included in our financial statements.

Use of Estimates in the Preparation of Financial Statements

Management prepares the financial statements in conformity with accounting principles generally accepted in the United States. This requires estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported periods. Some of the more significant estimates include oil and gas reserves, useful lives of assets, impairment of oil and gas properties, and future dismantlement and restoration liabilities. Actual results could differ from those estimates.

Cash and Cash Equivalents

Cash equivalents consist of highly liquid investments that mature within three months or less when purchased. Our cash equivalents consist primarily of institutional money market funds. We record cash equivalents at cost, which approximates their market value at the balance sheet date.

Concentration of Credit Risk

Our financial instruments that are potentially subject to a concentration of credit risk are principally cash and trade receivables. Our accounts receivable and accounts payable book values approximate fair value at the balance sheet date. Substantially all of our cash and cash equivalents at December 31, 2005 and 2004 exceeded the $100,000 federally insured limit for amounts deposited at financial institutions. At December 31, 2005, two companies accounted for approximately 70% of our total accounts receivable, and at December 31, 2004, three companies accounted for approximately 59% of our total accounts receivable. Oil and gas are fungible commodities in high demand from numerous customers; however, during 2005 we sold oil and gas to three major customers who accounted for 37%, 25% and 15% of our total revenues. The sale of oil and gas to four major customers accounted for 27%, 20%, 18% and 12% of our total oil and gas revenues in 2004. We do not believe that the loss of any of these customers would have a material adverse effect on our financial position or results of operations because we believe that they can be replaced due to the high demand for oil and gas.

Property and Equipment

We follow the successful-efforts method to account for oil and gas exploration and development expenditures. Under this method, we capitalize expenditures for leasehold acquisitions, drilling costs for productive wells and unsuccessful development wells. We amortize the capitalized costs using the units-of-production method, converting to gas equivalent units by using the ratio of 1 barrel of oil equal to 6 Mcf of gas.

Workovers that establish new production are capitalized and workovers that restore production are charged to operating expense.

Prior to 2003, we capitalized a discounted total of scheduled payments related to our license to use a library of 3-D seismic data. The amount capitalized was amortized to expense over the estimated minimum useful life of 4 years using a straight line method. In the fourth quarter of 2003, we completed a further review of the contracts and it was determined that as of the fourth quarter 2003, we would charge exploration expense as the invoices are paid. This change in our method of accounting for 3-D seismic data license did not have a material effect on our current or prior financial statements. During the second quarter of 2004, we acquired an additional license to access a library of 3-D seismic data covering the deeper water trends of the Gulf of Mexico. The agreement provides for a schedule of payments beginning with the delivery of the first data in May 2004 and ending in July 2008. Because of our unilateral right to terminate the license agreement, we do not consider any of the payments scheduled in the contract to be an incurred liability until the scheduled invoice date.

We review our oil and gas properties for impairment whenever events or circumstances indicate that the net book value of these properties may not be recoverable. If the net book value of a property is greater than the estimated undiscounted future net cash flow from the same property, the property is considered impaired. We base our assessment of possible impairment using our best estimate of future prices, costs and expected net cash flow generated by a property. The impairment expense is equal to the difference between the net book value and the fair value of the asset. We estimate fair value by discounting, at an appropriate rate, the future net cash flows from the property.

The impairment of unproved leasehold costs includes an amortization of the aggregate individually insignificant properties (adjusted by an estimated rate of future successful development) over an average lease term or, if events or circumstances indicate, a specific impairment of individually significant properties.

Other properties include improvements on the leased office space and office computers and equipment. We depreciate these assets using the straight-line method over their estimated useful lives, which range from 3 to 12 years.

Capitalization of Exploration Drilling Costs

We drill exploratory wells with the expectation that the final well bore will be capable of producing oil and gas reserves. The costs of drilling an exploratory well are capitalized as uncompleted wells pending the determination of whether the well has found proved reserves. If proved reserves are not found, these capitalized costs are charged to expense. On the other hand, the determination that proved reserves have been found results in the continued capitalization of the drilling costs of the well and its reclassification as a well containing proved reserves. It may be determined that an exploratory well may have found hydrocarbons at the time drilling is completed, but it may not be possible to classify the reserves at that time. In this case, we may continue to capitalize the drilling costs as an uncompleted well beyond one year when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project, or the reserves are deemed to be proved. At that time the well is either reclassified as a proved well or is considered impaired and its costs, net of any salvage value, are charged to expense.

Occasionally, we may salvage a portion of an unsuccessful exploratory well in order to continue exploratory drilling in an effort to reach the target geological structure/formation. In such cases, we charge only the unusable portion of the well bore to dry hole expense. We will continue to capitalize the costs associated with the salvageable portion of the well bore and add the costs to the new exploratory well. In certain situations, drilling is temporarily suspended and the well bore may be carried for more than one year because drilling to the depth of the target reserves is not yet complete. This may be due to the need to obtain, and/or analyze the availability of, equipment or crews or other activities necessary to pursue the targeted reserves or evaluate new or reprocessed seismic and geological data. If, after we analyze the new information and conclude that we will not reuse the well bore or if the well is determined to be unsuccessful after we complete drilling, we will charge the capitalized costs to dry hole expense. Total capitalized exploratory drilling costs charged to dry hole expense were $48.7 million for the year ended December 31, 2005, and $12.8 million for the year ended December 31, 2004.

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The following table shows the number of wells and the associated capitalized costs for wells in areas requiring a major capital expenditure before production can begin, where additional drilling efforts are not underway or firmly planned for the future and wells in areas not requiring major capital expenditures before production can begin, where more than one year has elapsed since the completion of drilling as of the end of December 31, 2005 and 2004. We are in the process of completing the infrastructure required to produce the reserves associated with this well.

	At December 31,			
	2005		2004	
	Wells	Cost	Wells	Cost
	(In thousands, except well numbers)			
Exploration wells requiring major capital expenditures	1	$ 2,067		$
Exploration wells not requiring major capital expenditures and capitalized for more than one year			1	4,445
Total	1	$ 2,067	1	$ 4,445

The following table presents exploratory costs deferred by year as of December 31, 2005.

	At December 31, 2005			
	Costs Deferred by Period			
	Total	Less than 1 Year	1 Year	2 or more Years
	(In thousands)			
Capitalized exploration costs	$12,952	$10,885	$2,067	

The following table shows the changes in capitalized exploratory drilling costs pending the determination of proved reserves, capitalized exploratory drilling costs that have been capitalized to wells and equipment, and the capitalized exploratory drilling costs charged to dry hole expense.

	At December 31,					
	2005		2004		2003	
	Wells	Cost	Wells	Cost	Wells	Cost
	(In thousands, except well numbers)					
Beginning balance	3	$ 12,777	2	$ 7,778		$
Reclassified to wells & facilities						
Dry hole expense				(2,861)		
Additions to capitalized costs	2	10,885	1	7,860	2	7,778
Other(1)	(2)	(10,710)				
Total	3	$ 12,952	3	$ 12,777	2	$ 7,778

(1) Other includes 2 wells withdrawn from suspended well status for utilization of the well bores for future identified exploration prospects.

Asset Retirement Obligations

We adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, effective January 1, 2003. The statement requires that we estimate the fair value for our asset retirement obligations (dismantlement and abandonment of oil and gas wells and offshore platforms) in the periods the assets are first placed in service. We then adjust the current estimated obligation for estimated inflation and market risk contingencies to the projected settlement date of the liability. The result is then discounted to a present value from the projected settlement date to the date the asset was first placed in service. As of January 1, 2003, we record the present value of the asset retirement obligation as an additional property cost and as an asset retirement liability. We recorded a combination of the amortization of the additional property cost (using the unit-of-production method) and the accretion of the discounted liability as a component of our depreciation, depletion and amortization of oil and gas properties.

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We base our initial liability on estimates of current costs to dismantle and abandon our existing platforms and wells on historical experience, industry practice, and external estimates of the cost to abandon similar platforms and wells subject to federal and state regulatory requirements. We increase the current liability estimate using a 3% annual inflation factor over the estimated productive life of the individual property and further increase the inflated liability by 5% for market cost risk. The liability is discounted using United States Treasury Securities with constant maturities that approximate the number of years of productive life for the property plus a 2.5% adjustment for credit risk. Revisions to the liability could occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding abandonment of wells.

Prior to our adoption of SFAS No. 143, we accrued an estimated dismantlement, restoration and abandonment liability using the unit-of-production method over the life of a property and included the accrued amount in depreciation, depletion and amortization expense. The total accrued liability ($5.5 million at December 31, 2002) was reflected as additional accumulated depreciation, depletion and amortization of oil and gas properties on our balance sheet.

In conformity with SFAS 143 we recorded the cumulative effect of this accounting change as of January 1, 2003, as if we had used this method in the prior years. At January 1, 2003, we increased our oil and gas properties by $9.0 million, recorded $11.8 million as an Asset Retirement Obligation liability and reduced our accumulated depreciation by $2.8 million ($5.5 million accrued dismantlement in prior years less accumulated depreciation, depletion and amortization of $2.7 million on the increased property costs). The adoption of the new standard had no material effect on our net income. The following pro forma data summarize our net income and net income per share for the year ended December 31, 2003, as if we had adopted the provisions of SFAS 143 on January 1, 2001, including aggregate pro forma asset retirement obligations on that date:

(In thousands, except per share amounts)		**Year Ended December 31, 2003**
Net income, as reported	$	42,924
Pro forma adjustment to reflect retroactive adoption of SFAS 143		34
Pro forma net income	$	42,958
Net income per share:		
Basic as reported	$	1.61
Basic pro forma	$	1.61
Diluted as reported	$	1.53
Diluted pro forma	$	1.53

Other Assets

Other assets include the long-term portion of prepaid pension expenses (see Note 8 Employee Benefit Plans Pension Plan), and the long-term portion of net unamortized credit facility origination fees. The origination fees are amortized on a straight-line basis over the term of the credit facility. We charge the amortized amount to interest and financing costs. In addition, other assets also include a long-term account receivable totaling approximately $397,000 and $385,000 at December 31, 2005 and 2004, respectively, which is CKB Petroleum s claim under Collateral Assignment Split Dollar Insurance Agreements among CKB Petroleum and Don D. Box (a former officer and member of the Board) and two of his brothers.

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Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses were as follows:

	At December 31, 2005	At December 31, 2004
	(In thousands)	
Accounts payable trade	$ 13,962	$ 28,214
Accrued payables	55,191	31,442
Income taxes payable		3,240
Advance billings	3,721	1,970
Royalties and other revenue payable	3,687	4,473
Total accounts payable and accrued expenses	$ 76,561	$ 69,339

Oil and Gas Revenues

When oil and gas is produced, we sell it immediately. Consequently, we recognize oil and gas revenue under the sales method in the month of actual production based on our share of the revenues. Our actual sales have not been materially different from our entitled share of production, and we do not have any significant gas imbalances.

Transportation costs

We include transportation costs in operating costs and expenses. During the years ended December 31, 2005, 2004, and 2003, we incurred transportation costs totaling $2.0 million, $2.6 million, and $2.3 million, respectively.

Stock Options

In December 2002, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 148, Accounting for Stock-Based Compensation Transition and Disclosure (SFAS 148). SFAS 148 amends Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation (SFAS 123), to provide alternative methods of transition to SFAS No. 123 s fair value method of accounting for stock-based employee compensation.

SFAS 148 also amends the disclosure provisions of SFAS 123 and Accounting Principles Board Opinion No. 28, Interim Financial Reporting, to require disclosure in the summary of significant accounting policies of the effects of an entity s accounting policy with respect to stock-based employee compensation on reported net income and earnings per share in annual and interim financial statements. While SFAS 148 does not amend SFAS 123 to require companies to account for employee stock options using the fair value method, the disclosure provisions of SFAS 148 are applicable to all companies with stock-based employee compensation, regardless of whether they account for that compensation using the fair value method of SFAS 123 or the intrinsic value method of Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees (APB 25).

We apply the accounting provisions of APB 25 and related interpretations to account for stock-based compensation and have adopted the disclosure requirements of SFAS 123 and SFAS 148. Accordingly, we measure compensation cost for stock options as the excess, if any, of the quoted market price of our stock at the date of the grant over the amount an employee must pay to acquire the stock. All of our options are granted with exercise prices at or above the quoted market price on the date of grant.

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The following table summarizes relevant information as to the reported results under our intrinsic value method of accounting for stock awards, with supplemental information as if the fair value recognition provision of SFAS 123 had been applied:

	For Years Ended December 31, 2005	2004	2003
	(In thousands, except per-share amounts)		
As reported:			
Net income	$ 70,567	$ 60,996	$ 42,924
Basic income per share	$ 2.48	$ 2.23	$ 1.61
Diluted income per share	$ 2.37	$ 2.14	$ 1.53
Stock based compensation (net of tax at statutory rate of 35%) included in net income as reported	$ 3,015	$ 928	$ 1,017
Stock based compensation (net of tax at statutory rate of 35%) if using the fair value method as applied to all awards	$ 3,015	$ 6,711	$ 3,146
Pro forma (if using the fair value method applied to all awards):			
Net income	$ 70,567	$ 55,213	$ 40,795
Basic income per share	$ 2.48	$ 2.02	$ 1.53
Diluted income per share	$ 2.37	$ 1.94	$ 1.46
Weighted average shares used in computation			
Basic	28,488	27,408	26,628
Diluted	29,722	28,441	27,987

During 2004, we accelerated the vesting dates for 128,324 stock options granted during 2002, and 39,999 stock options granted during 2003, from the original vesting dates in 2005 and 2006 to vesting dates in December 2004. All stock options were in the money at the time the vesting dates were accelerated. The acceleration of the vesting increased the stock based compensation using the fair value method under SFAS 123 by $1.1 million, net of tax at the statutory rate of 35%. As a result of this acceleration all of our outstanding stock options were vested at December 31, 2004.

The fair value of each option grant for the years ended December 21, 2004 and 2003, is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions:

	For Years Ended December 31, 2004	2003
Expected life (years)	7	7
Interest rate	4.07%	3.73%
Volatility	63.70%	65.27%
Dividend yield	0%	0%

As required, the pro forma disclosures above include options granted since January 1, 1995. All of our outstanding or previously-exercised options were granted after 1995.

Segment Reporting

We operate in only one business segment.

General and Administrative Expenses

We report our general and administrative expenses net of reimbursed overhead costs that we allocate to working interest owners of the oil and gas properties that we operate.

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Income Taxes

Income tax expense or benefit includes both current income taxes and deferred income taxes. Deferred income tax expense or benefit equals the change in the net deferred income tax asset or liability from the beginning of the year. We determine the amount of our deferred income tax asset or liability by multiplying the enacted tax rates by the temporary differences, net operating or capital loss carry-forwards plus any tax credit carry-forwards. The tax rates used are the effective rates applicable for the year in which we expect the temporary differences or carry-forwards to reverse.

In December 2004, the FASB issued Staff Position No. FAS 109-1 (FAS 109-1), Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities by the American Jobs Creation Act of 2004. The American Jobs Creation Act of 2004 (the AJCA) introduces a special 9% tax deduction on qualified production activities. FAS 109-1 clarifies that this tax deduction should be accounted for as a special tax deduction in accordance with FASB Statement No. 109. The deduction is being phased in over a period of time. For 2005, the deduction is equal to 3% of qualified production activities. We computed a deduction of approximately $250,000 for 2005.

Income per Common Share

We compute basic income per share by dividing net income by the weighted average number of common shares outstanding for the period. Diluted income per share reflects the potential dilution that could occur if options or other contracts to issue common stock were exercised or converted into common stock or resulted in the issuance of common stock that then shares in the net income of the company. The following table presents our calculation of basic and diluted income per share.

	For Years Ended December 31,		
	2005	2004	2003
	(In thousands, except per-share amounts)		
Net income available for basic income per share	$ 70,567	$ 60,996	$ 42,924
Basic income per share	$ 2.48	$ 2.23	$ 1.61
Diluted income per share	$ 2.37	$ 2.14	$ 1.53
Weighted average common shares for basic income per share	28,488	27,408	26,628
Dilutive stock options outstanding (treasury stock method)	483	837	1,099
Common stock grant	751	196	260
Total common shares for diluted income per share	29,722	28,441	27,987
Non-dilutive stock options outstanding	266	749	1,235

New Accounting Pronouncements

In April 2005, the FASB issued Staff Position No. FAS 19-1, Accounting for Suspended Well Costs, (FSP 19-1). FSP 19-1 amends SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, (SFAS 19) to allow continued capitalization of exploratory well costs beyond one year from the completion of drilling under circumstances where the wells have found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. FSP 19-1 also amends SFAS 19 to require enhanced disclosures of suspended exploratory well costs in the notes to the financial statements for annual and interim periods when there has been a significant change from the previous disclosure. The guidance in FSP 19-1 was effective for the first reporting period beginning after April 4, 2005. Accordingly, we adopted the new requirements and have included the required disclosures in footnote 1. The adoption of FSP 19-1 did not impact our financial position or results of operations.

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In December 2004, the FASB issued Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payment (SFAS 123R), which is a revision of Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation (SFAS 123). SFAS 123R supersedes Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees (APB 25) and amends Statement of Financial Accounting Standards No. 95, Statement of Cash Flows . Generally, the approach in SFAS 123R is similar to the approach described in SFAS 123. However, SFAS 123R will require all share-based payments to employees, including grants of employee stock options, to be recognized in our Consolidated Statements of Operations based on their fair values. Pro forma disclosure is no longer an alternative. SFAS 123R must be adopted no later than January 1, 2006, and permits us to adopt its requirements using one of two methods:

A modified prospective method in which compensation cost is recognized beginning with the effective date based on the requirements of SFAS 123R for all share-based payments granted after the effective date and based on the requirements of SFAS 123 for all awards granted to employees prior to the adoption date of SFAS 123R that remain unvested on the adoption date.

A modified retrospective method which includes the requirements of the modified prospective method described above, but also permits entities to restate either all prior periods presented or prior interim periods of the year of adoption based on the amounts previously recognized under SFAS 123 for purposes of pro forma disclosures.

We have elected to adopt the provisions of SFAS 123R on January 1, 2006, using the modified prospective method. As permitted by SFAS 123, we currently account for share-based payments to employees using the intrinsic value method prescribed by APB 25 and related interpretations. Therefore, we do not recognize compensation expenses associated with employee stock options. Currently, since all of our outstanding stock options have vested prior to the adoption of SFAS 123R, we will not recognize any expenses associated with these prior stock option grants. However, the adoption of SFAS 123R fair value method could have a significant impact on our future results of operations for future stock or stock option grants but no impact on the our overall financial position. Had we adopted SFAS 123R in prior periods, the impact would have approximated the impact of SFAS 123 as described in the pro forma net income and income per share disclosures. The adoption of SFAS 123R will have no effect on our outstanding stock grant awards.

SFAS 123R also requires the tax benefits of tax deductions in excess of recognized compensation expenses to be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement may reduce our future cash provided by operating activities and increase future cash provided by financing activities, to the extent of associated tax benefits that may be realized in the future. While we cannot estimate what those amounts will be in the future (because they depend on, among other things, when employees exercise stock options), the amount of operating cash flows from such excess tax deductions were $5.4 million during the year ended December 31, 2005.

In March 2005, the FASB issued FASB Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations. The interpretation clarifies the requirement to record abandonment liabilities stemming from legal obligations when the retirement depends on a conditional future event. FIN No. 47 requires that the uncertainty about the timing or method of settlement of a conditional retirement obligation be factored into the measurement of the liability when sufficient information exists. We adopted FIN No. 47 as of December 31, 2005. There was no material impact on our results of operations, financial condition, or cash flows.

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154, Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statements No. 3 (SFAS 154). SFAS 154 requires retrospective application to prior period financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS 154 will become effective on January 1, 2006. The impact of SFAS 154 will depend on the nature and extent of any voluntary accounting changes and correction of errors after the effective date, but we do not currently expect SFAS 154 to have a material impact on our results of operations, financial condition, or cash flows.

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Note 2 Oil and Gas Properties

The following table summarizes the capitalized costs on our oil and gas properties, all of which are located in the United States.

	At December 31,					
	2005			2004		
	Proved	Unproved	Total	Proved	Unproved	Total
	(In thousands)					
Oil and gas properties	$ 874,579	$ 33,858	$ 908,437	$ 717,316	$ 26,899	$ 744,215
Accumulated depreciation, depletion and amortization	(465,968)		(465,968)	(407,134)		(407,134)
Net oil and gas properties	$ 408,611	$ 33,858	$ 442,469	$ 310,182	$ 26,899	$ 337,081

The following table presents a summary of our oil and gas expenditures during the last three years.

	For Years Ended December 31,		
	2005	2004	2003
	(In thousands)		
Unproved acquisition costs	$ 8,985	$ 10,878	$ 2,370
Proved acquisition costs	3,024	1,554	1,466
Exploration costs	111,427	80,970	54,138
Development costs	94,525	65,080	58,475
Discounted estimate of future asset retirement costs	2,770	4,267	9,963
Total	$ 220,731	$ 162,749	$ 126,412

We recognized impairment expenses shown in the table below:

	For Years Ended December 31,		
	2005	2004	2003
	(In thousands)		
Unproved properties	$ 1,238	$ 1,130	$ 1,136
Proved properties		9,746	3,311
Other	245		
Total impairment expense	$ 1,483	$ 10,876	$ 4,447

We estimate the amount of individually insignificant unproved properties which will prove unproductive by amortizing the balance of our individually immaterial unproved property costs (adjusted by an anticipated rate of future successful development) over an average lease term. Individually significant properties will continue to be evaluated periodically on a separate basis for impairment. We will transfer the original cost of an unproved property to proved properties when we find commercial oil and gas reserves sufficient to justify full development of the property. The impairment of unproved properties for the prior two years primarily resulted from the actual (due to unsuccessful exploration results) or impending forfeiture of leaseholds.

We analyze proved properties for impairment indicators based on the proved reserves as determined by our internal reserve engineers. No proved properties were impaired during 2005. The properties impaired in 2004 primarily consisted of two properties in the Gulf of Mexico which totaled $4.2 million and two onshore Gulf Coast properties which totaled $5.5 million, and in 2003 included two properties in the Gulf of Mexico which totaled $2.4 million and one property in the onshore Gulf Coast. The impairments resulted primarily from wells depleting sooner than originally estimated or capital costs in excess of those anticipated.

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The following table summarizes our asset retirement obligation. The beginning balance in 2003 is presented on a pro forma basis as if the provisions of SFAS 143 had been applied when the properties were placed in service:

	At December 31,		
	2005	2004	2003
	(Unaudited, in thousands)		
Beginning of period	$ 16,030	$ 12,446	$ 11,807
New properties and changes in estimates	3,439	4,267	1,393
Net settlement of liabilities(1)	645	(1,712)	(1,631)
Loss on settlement of liabilities	75	21	
Accretion of liability	1,186	1,008	877
End of period	$ 21,375	$ 16,030	$ 12,446

(1) In 2005, we received $700,000 as consideration for our assumption of dismantlement and abandonment liabilities for existing facilities on a property we acquired in 2005.

Note 3 Insurance Receivable

As a result of Hurricanes Katrina and Rita which occurred in August and September of 2005, we incurred physical damages and shut-in production on many of our offshore properties. We maintain insurance coverage for damages to our offshore properties, including producing and drilling wells, platforms, pipelines and lost production. As of December 31, 2005, we have $23.3 million accrued as an insurance receivable on the balance sheet. Of this amount, $15.0 million represents insurance receivables for hurricane related expenditures associated with physical damage and lost equipment and a control of well claim. The remaining $8.3 million represents an insurance receivable for partial claim for lost production settled through December 31, 2005, from shut-ins caused by Hurricane Rita and is included in other income on the income statement. Additional claims associated with lost production as a result of Hurricane Katrina have been made and will be recorded when finalized.

Note 4 Notes Payable and Other Long-Term Payables

Bank Credit Facility

On September 9, 2005, we increased our credit facility from $150 million to $200 million and the associated borrowing base from $100 million to $150 million. The following schedule reflects certain information about the line of credit for the last two years.

	At December 31,	
	2005	2004
	(In thousands)	
Borrowing base	$ 150,000	$ 100,000
Outstanding balance		

Available amount	$ 150,000	$ 100,000

We pledged certain oil and gas properties as collateral for this line of credit. We accrue and pay interest at varying rates based on premiums ranging from 1.0 to 2.0 percentage points over the London Interbank Offered Rates. We pay commitment fees of 0.375% on the unused amount of the line of credit. Interest only is payable quarterly through September 2009, at which time the line expires and all principal becomes due, unless the line is extended or renegotiated.

The most significant financial covenants in the line of credit include, among others, maintaining a minimum current ratio (as defined in the facility agreement) of 1.0 to 1.0, a minimum tangible net worth of $175.0 million plus 50% of net income (accumulated from the closing date of the facility agreement) and 75% of the net proceeds of any corporate equity offering, and interest coverage of 2.5 to 1.0. We are currently in compliance with these financial covenants. If we do not comply with these covenants, the lenders have the right to refuse to advance additional funds under the facility and/or declare all principal and interest immediately due and payable.

The banks review the borrowing base semi-annually and may decrease or propose an increase to the borrowing base at their discretion relative to the new estimate of proved oil and gas reserves.

Note 5 Commitments and Contingent Liabilities

We currently lease approximately 19,000 square feet of office space in Dallas, Texas and have commitments to lease an additional 6,000 square feet in 2006. The non-cancelable operating lease expires in March 2012. The following table reflects our rent expense for the past three years and the commitment for the future minimum rental payments.

Year	**(In Thousands)**	
2003	$	441
2004	$	441
2005	$	489
2006	$	644
2007	$	672
2008	$	678
2009	$	680
2010	$	686
After 2010	$	860

We have no material pending legal proceedings.

Effective May 12, 2004, we entered into an executory contract with a third party under which we acquired a license to use 3-D seismic data owned by the vendor covering approximately 1,200 blocks in the Gulf of Mexico. We do not acquire ownership of the data, but simply a non-exclusive license to use the data. The term of the agreement, subject to a mutual right of termination by either party, is 20 years from delivery of the data. At the end of the 20 year term, the license shall be renewed for an additional 20 year term at no charge unless the parties agree to terminate the agreement. The following table reflects the expense for 2004 and 2005 and the amount of future payments for each specified year under the contract.

Year	**(In Thousands)**	
2004	$	4,219
2005	$	3,718
2006	$	3,000
2007	$	3,000
2008	$	1,940

The licensor delivered to us all the 3-D seismic data under the agreement within the first three months of execution, as contemplated in the agreement, and we have full access to the data. In addition to the terms of the agreement described above, under the agreement the licensor has ongoing warranty and indemnity responsibilities as to intellectual property matters and the obligation to deliver to us certain data tapes and support data upon our request. Further, we believe that under the terms of the agreement we have the unilateral right to terminate the agreement by non-payment of two scheduled quarterly payments and because there is no provision restricting termination of the agreement, and that upon such termination we have no further obligations under the agreement, except for the return of the data to the licensor.

Note 6 Common Stock, Preferred Stock and Dividends

We have 100.0 million shares of common stock and 25.0 million shares of blank check preferred stock authorized. The par value of the common stock and preferred stock is $0.01 per share. The Board of Directors can approve the issue of multiple series of preferred stock and set different terms, voting rights, conversion features, and redemption rights for each distinct series of the preferred stock.

We have reserved approximately 4.0 million shares of common stock for our 1997 Stock Option Plan and for our Non-Employee Director Stock Purchase Plan. In addition, we have reserved 2.0 million shares of common stock for our 2004 Stock Incentive Plan approved by our stockholders on May 24, 2004. Both plans are discussed in more detail in Note 7 Stock Based Compensation Expense. Dividend payments are currently prohibited by our line of credit agreement.

Note 7 Stock Based Compensation Expense

1997 Stock Option Plan

The Compensation Committee of the Board of Directors, comprising three independent directors, administers the 1997 Stock Option Plan. This committee has the discretion to determine the participants, the number of shares granted to each person, the exercise price of the common stock covered by each option, and most other terms of the option. Options granted under the plan may be either incentive stock options or non-qualified stock options. The committee may issue options for up to 3.75 million shares of common stock, but no more than 937,500 shares to any individual. Forfeited options are available for future issuance. In accounting for stock options granted to employees and directors, we have chosen to continue to apply the accounting method promulgated by Accounting Principles Board Opinion No. 25 (APB 25) rather than apply an alternative method permitted by Statement of Financial Accounting Standards No. 123 (SFAS 123). Under APB 25, at the time of grant we do not record compensation expense on our income statement for stock options granted to employees or directors.

A summary of our stock option plan as of December 31, 2005, 2004, and 2003, and changes during the years ending on those dates is presented below:

	At December 31,					
	2005		2004		2003	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	1,528,439	$ 13.00	2,334,333	$ 10.93	2,552,219	$ 8.68
Granted			30,000	23.24	360,000	18.66
Exercised	(825,786)	12.54	(835,894)	7.58	(559,553)	5.44
Forfeited					(18,333)	16.82
Outstanding at end of year	702,653	$ 13.54	1,528,439	$ 13.00	2,334,333	$ 10.93
Options exercisable at year-end	702,653	$ 13.54	1,528,439	$ 13.00	1,592,667	$ 7.81
Weighted-average fair value of options granted during the year		$		$ 15.23		$ 12.33

The options outstanding at December 31, 2005, have a weighted-average remaining contractual life of 5.51 years and an exercise price ranging from $3.75 to $23.89 per share. A breakdown of the options outstanding at December 31, 2005 by price range is presented below:

Option Price Range	Number	Weighted Average Exercise Price	Weighted Average Remaining Life (Years)	Number Exercisable	Weighted Average Price of Options Exercisable
\$3.75 - \$4.25	98,866	\$ 3.87	4.17	98,866	\$ 3.87
\$5.75 - \$6.94	67,201	\$ 6.63	1.55	67,201	\$ 6.63
\$9.00 - \$15.32	211,206	\$ 12.53	4.28	211,206	\$ 12.53
\$17.15 - \$23.89	325,380	\$ 18.57	7.52	325,380	\$ 18.57

The effect on our net income if we recorded the estimated compensation costs for the stock options using the estimated fair value as determined by applying the Black-Scholes option pricing model is included in Note 1 Summary of Significant Accounting Policies Stock Options.

During 2004, we accelerated the vesting dates for 128,324 stock options granted during 2002, and 39,999 stock options granted during 2003, from the original vesting dates in 2005 and 2006 to vesting dates in December 2004. All stock options were in the money at the time the vesting dates were accelerated. The acceleration of the vesting increased the stock based compensation using the fair value method under SFAS 123 by $1.1 million, net of tax at statutory rate of 35%. As a result of this acceleration all of our outstanding stock options are vested at December 31, 2004.

Non-Employee Director Stock Purchase Plan

The Non-Employee Director Stock Purchase Plan allows the non-employee members of the Board to receive their directors fees in shares of restricted common stock instead of cash. The number of shares received will be equal to 150% of the cash fees divided by the closing market price of the common stock on the day that the cash fees would otherwise be paid. The director cannot transfer the common stock until the earlier of one year after issuance or the termination of a director resulting from death, disability, removal, or failure to be nominated for an additional term. The director can vote the shares of restricted stock and receive any dividend paid.

Employee and Director Stock Grants and Our 2004 Stock Incentive Plan

In June 1999, the Board of Directors approved a contingent stock grant to our employees and directors totaling 686,472 shares. The shares under this grant vest over 3 to 5 years. In order for the grant to become effective, the price of our stock had to increase from $4.19 per share to a trigger price of $10.42 per share and close at or above $10.42 per share for 20 consecutive trading days within 5 years of the grant date. On January 24, 2001, the stock price closed above the trigger price for the twentieth consecutive trading day. On that date, we measured the total compensation cost at $8.1 million which was the total number of shares granted multiplied by the market price on that date. We recorded $8.1 million as restricted common stock and unearned compensation.

In May 2004, the stockholders approved the Remington Oil and Gas Corporation 2004 Stock Incentive Plan. This plan is administered by the Compensation Committee of the Board of Directors. Under this plan the Committee may issue stock options, purchased stock, bonus stock, stock appreciation rights, phantom stock, restricted stock awards, performance awards and other stock or performance based awards. All employees and non-employee directors are eligible to participate. In October 2004, the Board approved a stock grant of an aggregate 200,000 shares to employees and non-employee directors and an additional grant of 6,000 shares in April 2005. The shares under this grant vest one-fifth each October for the years 2005 through 2009. There is no trigger price or conditions under this stock grant other than a written stock grant agreement between us and the grantee, and the passage of time and continued employment or service of a director for vesting purposes. We recorded $0.2 million and $5.2 million as restricted common stock and as unearned compensation in 2005 and 2004, respectively.

In April 2005, the Board of Directors pursuant to the 2004 Stock Incentive Plan approved a restricted stock grant for all employees and the non-employee directors totaling 665,000 shares and approved a grant for an additional 20,000 shares in October 2005. The shares under this grant vest 25%, 25%, and 50% each April of 2008, 2009 and 2010, respectively. In addition, vesting of the grant may be accelerated under certain circumstances including our stock price closing at or above $55.80 per share, or a change in control of the company. Prior to vesting, the grantee shall have the right to vote the shares and receive any dividends. Such rights, however, will cease in the event the grantee s service with us is terminated under conditions which do not cause an accelerated vesting of the grant shares. We recorded $19.3 million as restricted common stock and unearned compensation.

Unearned compensation is reported as a separate reduction in stockholders equity on the balance sheet and is amortized to stock compensation expense on a straight line basis over the life of the grant. During each of the years ended December 31, 2005, 2004 and 2003, we amortized $4.6 million, $1.3 million and $1.3 million, respectively, to stock based compensation expense. The total compensation expense may decrease if a grant fails to vest in accordance with its terms.

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A summary of all stock grants as of December 31, 2005, 2004 and 2003, and changes during the years ending on those dates is presented below:

	At December 31,					
	2005		2004		2003	
	Shares	Weighted Average Price	Shares	Weighted Average Price	Shares	Weighted Average Price
Outstanding at beginning of period	329,382	$ 20.49	259,636	$ 12.16	447,192	$ 12.16
Grants	691,000	28.12	200,000	25.88		
Vested	(110,984)	17.27	(130,254)	12.16	(173,228)	12.16
Forfeited	(600)	25.88			(14,328)	12.16
Outstanding at end of year	908,798	$ 26.68	329,382	$ 20.49	259,636	$ 12.16

Note 8 Employee Benefit Plans

Pension Plans

Remington and CKB Petroleum, Inc. each have a noncontributory defined benefit pension plan. The retirement benefits available are generally based on years of service and average earnings. We fund the plans with contributions at least equal to the minimum funding provisions of employee benefit and tax laws, but usually no more than the maximum tax deductible contribution allowed. Plan assets consist primarily of equity and fixed income securities. The following tables set forth significant information about the plans, the reconciliation of the benefit obligation, plan assets, and funded status for the pension plans. We use a December 31 measurement date for the plan.

	At December 31,	
	2005	2004
	(In thousands)	
Reconciliation of the change in projected benefit obligation		
Beginning projected benefit obligation	$ 7,083	$ 6,032
Service cost	588	591
Interest cost	400	373
Actuarial (gain) loss	(302)	298
Benefits paid	(1,054)	(211)
Ending projected benefit obligation	$ 6,715	$ 7,083
Reconciliation of the change in plan assets		
Beginning market value	$ 6,526	$ 5,989
Actual return on plan assets	290	574
Employer contributions	600	174
Benefit payments	(1,054)	(211)

Ending market value	$ 6,362	$ 6,526

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	At December 31, 2005	At December 31, 2004
	(In thousands)	
Funded status and amounts recognized in the balance sheet		
Excess of assets over projected benefit obligation	$ (353)	$ (557)
Unrecognized net actuarial loss	2,307	2,498
Unrecognized prior service costs	33	36
Adjusted net prepaid benefit cost recognized	$ 1,987	$ 1,977
Accumulated benefit obligation	$ 6,016	$ 5,907
Assumptions used to determine benefit obligations		
Discount rate	6.00%	6.00%
Rate of compensation increase	3.00%	3.00%

Cash flows

Contributions

We do not expect to make a contribution in 2006.

Estimated future benefit payments

We expect to pay the following benefit payments, which reflect expected future service, as appropriate, and assume that future retirees will elect a lump-sum form of benefit.

	(In Thousands)
2006	$ 1,001
2007	196
2008	190
2009	852
2010	180
2011 through 2015	2,490

The net periodic pension cost recognized in our income statements includes the following components:

	For Years Ended December 31, 2005	2004	2003
		(In thousands)	
Components of net periodic pension cost			
Service cost	$ 588	$ 591	$ 415
Interest cost on projected benefit obligation	400	373	322

Expected return on plan assets	(514)	(471)	(352)
Recognized net actuarial loss	113	155	154
Amortization of prior service costs	3	3	3
Net periodic pension cost	$ 590	$ 651	$ 542
Assumptions used to determine net periodic pension costs			
Discount rate	6.00%	6.00%	6.50%
Expected return on plan assets	8.00%	8.00%	8.00%
Rate of compensation increase	3.00%	3.00%	3.00%

To estimate the expected long-term rate of return on pension plan assets, we consider the current and expected asset allocations, as well as historical returns on equities and debt securities.

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The accumulated benefit obligation represents the present value of the benefits earned to the measurement date, with benefits computed based on current compensation levels. The projected benefit obligation is the accumulated benefit obligation increased to reflect expected future compensation.

Remington s aggregate projected benefit obligation at December 31, 2005, was $6.0 million and the aggregate fair value of plan assets was $5.5 million. On December 31, 2005, Remington had a prepaid benefit cost of $1.6 million. CKB Petroleum s aggregate projected benefit obligation at December 31, 2005, was $687,000 and the aggregate fair value of plan assets was $843,000. On December 31, 2005, CKB Petroleum had a prepaid benefit cost of $433,000.

Plans asset allocation (Plans assets are held in trust.)

	At December 31,	
	2005	**2004**
Asset category		
Equity securities	64.9%	71.2%
Debt securities	21.4%	19.7%
Money funds	13.7%	9.1%
Total	100.0%	100.0%

Money fund balances were disproportionately high at each year end because we made large contributions to the pension trusts during the last few days of each year. These funds were allocated to equity and debt securities and utilized for regular distributions to retirees during the early part of the next year. See the discussion of our investment policy below.

Plan fiduciaries set investment policies, strategies, and guidelines for the pension trusts. These include

Achieve a long-term average annual rate of return of at least 8%.

Asset allocations ranging from 75% equities and 25% debt securities to 25% equities and 75% debt securities.

Recommended long-term average allocation is 60% equities and 40% debt securities.

Permissible investments include publicly-traded common and preferred stocks, convertible bonds, fixed income securities, guaranteed investment contracts, and money market funds. Transactions are not permitted in futures contracts or options.

Broad diversification of plan assets.

Plan fiduciaries have appointed an investment advisor and asset managers. A Plan Administration Committee, comprising three company executive officers, meets with the investment advisor at least quarterly to review overall investment performance, asset manager performance, current asset category allocations, recommended asset category allocations for the coming quarter, and sources of liquidity for distributions to retirees for the coming quarter. During the latter part of 2002 the committee, with the assistance of the investment advisor, set the target allocation at 75% equities and 25% debt securities and has maintained that target allocation continuously since then.

Employee Severance Plan, Post Retirement Benefits and Post Employment Benefits

Our employee severance plan provides severance benefits ranging from 2 months to 18 months of the employee s base salary if the employee is terminated involuntarily. The plan incorporates the provisions and terms of any individual contract or agreement that an employee may have with the company. Certain of the executive officers have individual employment contracts with the company.

We have never paid postretirement benefits other than pensions, and we are not obligated to pay such benefits in the future. Future obligations for postemployment benefits are immaterial. Therefore, we have not recognized any liability for them.

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Note 9 Income Taxes

The following table provides a summary of our income tax expense:

	For Years Ended December 31, 2005	2004	2003
	(In thousands)		
Current			
Federal	$ 8,745	$ 7,755	$ 175
State	62	147	
	8,807	7,902	175
Deferred			
Federal	29,760	24,688	23,113
State	425	346	330
	30,185	25,034	23,443
Total income tax expense	$ 38,992	$ 32,936	$ 23,618

Total income tax expense differs from the amount computed by applying the federal income tax rate to net income before income taxes as follows:

	For Years Ended December 31, 2005	2004	2003
	(In thousands)		
Federal income tax expense at statutory rate	$ 38,346	$ 32,876	$ 23,290
State income tax expense	487	493	
Other	159	(433)	328
Total income tax expense	$ 38,992	$ 32,936	$ 23,618

The following table reflects the significant components of our net deferred tax liability.

	At December 31, 2005	2004
	(In thousands)	
Deferred tax liabilities		
Oil and gas properties	$ (87,237)	$ (56,335)
Prepaid insurance	(1,094)	
Pension	(591)	(598)

Total deferred tax liabilities	(88,922)	(56,933)
Deferred tax assets		
Asset retirement obligation	3,335	2,520
Other assets	1,617	628
Total deferred tax assets	4,952	3,148
Net deferred tax (liability)	$ (83,970)	$ (53,785)

Note 10 Subsequent Event

On January 22, 2006 we entered into a merger agreement with Helix Energy Solutions Group, Inc. (formerly Cal Dive International, Inc.). Consideration for the offer from Helix will be $27.00 in cash and 0.436 shares of Helix stock for each of our shares. Completion of the merger is expected in the second quarter of 2006, however, it is subject to customary conditions to closing, including without limitation, approval by our stockholders. We and Helix will file a proxy statement/prospectus and other relevant documents concerning the proposed merger and the special meeting of our stockholders which will be called seeking approval of the transaction.

We have entered into the following agreements for forward sales of production for the period March 2006 through June 2007:

Oil:	1,000 bbls/day @ $70.00/bbl	March 2006-February 2007
Gas:	20 mmbtu/day @ $9.83/mmbtu	March 2006-August 2006
	10 mmbtu/day @ $8.88/mmbtu	September 2006-December 2006
	20 mmbtu/day @ $9.72/mmbtu	January 2007-June 2007

Note 11 Oil and Gas Reserves and Present Value Disclosures (Unaudited)

The estimates of oil and gas reserves were prepared by us and audited by Netherland, Sewell & Associates, Inc. an independent reserve engineering firm. The determination of these reserves is a complex and interpretative process that is subject to continued revision as additional information becomes available. In many cases, a relatively accurate determination of reserves may not be possible for several years due to the time necessary for development drilling, testing and studies of the reservoirs. We do not file reserve estimates with any other federal authority or agency.

The quantities of proved oil and gas reserves presented below include only the amounts which we reasonably expect to recover in the future from known oil and gas reservoirs under the current economic and operating conditions. Proved reserves include only quantities that we can commercially recover using current prices, costs, existing regulatory practices and technology. Therefore, any changes in future prices, costs, regulations, technology or other unforeseen factors could significantly increase or decrease proved reserve estimates. Our proved undeveloped reserves are generally brought on line within 12 months. Alternatively, they are associated with long life fields where economics dictate waiting for an existing wellbore available for sidetrack, or waiting to mobilize a platform rig for operations. Accordingly, proved undeveloped reserves in major fields may be carried for many years. The following table presents our net ownership interest in proved oil and gas reserves.

	At December 31,					
	2005		2004		2003	
	Oil Bbls	Gas Mcf	Oil Bbls	Gas Mcf	Oil Bbls	Gas Mcf
	(In thousands)					
Beginning of period	16,899	150,699	11,619	142,432	13,114	124,967
Revisions of previous estimates	1,736	(16,776)	1,862	(12,801)	(363)	(5,754)
Extensions, discoveries and other	1,234	57,405	5,093	49,125	337	42,676
Reserves purchased					306	4,692
Reserves sold	(4)	(508)				
Production	(1,484)	(22,161)	(1,675)	(28,057)	(1,775)	(24,149)
End of period	18,381	168,659	16,899	150,699	11,619	142,432
Proved developed reserves	9,511	102,447	6,858	89,376	7,071	76,475

The following tables represent value-based information about our proved oil and gas reserves. The standardized measure of discounted future net cash flows results from the application of specific criteria applicable to the value-based disclosures of all oil and gas reserves in the industry. Due to the imprecise nature of estimating oil and gas reserve quantities and the uncertainty of future economic conditions, we cannot make any representation about interpretations that may be made or what degree of reliance that may be placed on this method of evaluating proved oil and gas reserves.

We compute future cash revenue by multiplying the year-end commodity prices, or contractual pricing if applicable, by estimated future production from proved oil and gas reserves. We use year-end West Texas Intermediate posted prices per barrel and Henry Hub spot market prices per MMBtu adjusted by property for energy content, quality, transportation fees, and regional price differentials.

	Years Ended December 31, 2005	2004	2003
West Texas Intermediate posted price (per barrel)	$ 57.75	$ 40.25	$ 29.25
Henry Hub spot market price (per MMbtu)	$ 10.08	$ 6.18	$ 5.97

We estimated the costs based on the prior year costs incurred for individual properties, or similar properties if a particular property did not have production during the prior year. Future income tax expense was determined by applying the current statutory tax rate to the estimated future net cash flow from all properties. Finally, we discounted the future net cash flow, after tax, by 10% per year to arrive at the standardized measure of discounted future net cash flows presented below.

	At December 31, 2005	2004 (In thousands)	2003
Oil and gas revenues	$ 2,713,983	$ 1,581,927	$ 1,206,775
Production costs	(200,297)	(192,761)	(165,733)
Development, dismantlement and abandonment costs(1)	(148,514)	(150,596)	(140,175)
Income tax expense	(706,403)	(323,492)	(223,929)
Net cash flow	1,658,769	915,078	676,938
10% annual discount	(421,786)	(276,229)	(190,642)
Standardized measure of discounted future net cash flows	$ 1,236,983	$ 638,849	$ 486,296

(1) Based on our Netherland, Sewell & Associates audited reserve report as of December 31, 2005, we estimate that the amount of capital required to convert proved undeveloped reserves to proved developed reserves will be \$113.0 million of the \$121.1 million of future development costs, including \$62.8 million in 2006, \$12.1 million in 2007 and \$7.6 million in 2008. Our actual expenditures may differ from these estimates. Capital expenditures incurred to develop proved undeveloped reserves were \$40.2 million in 2005, \$21.8 million in 2004 and \$28.4 million in 2003.

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The following table summarizes the principal sources of change in the standardized measure of discounted future net cash flows from year to year.

	At December 31, 2005	2004 (In thousands)	2003
Standardized measure of discounted cash flows at beginning of year	$ 638,849	$ 486,296	$ 351,042
Sales and transfers of oil and gas produced, net of production costs	(232,065)	(208,492)	(161,670)
Net changes in prices and production costs	578,486	76,957	134,883
Net changes in estimated development costs	(68,504)	(40,570)	(13,169)
Net changes in income tax expense	(302,104)	(63,665)	(47,324)
Extensions, discoveries and improved recovery less related costs	436,613	321,813	141,970
Proved oil and gas reserves purchased			13,998
Proved oil and gas reserves sold	(2,192)		
Previously estimated development costs incurred during the year	70,061	32,932	28,477
Revisions of previous quantity estimates	(42,847)	(6,579)	(34,006)
Other changes	96,801	(25,026)	36,991
Accretion of discount	63,885	65,183	35,104
Standardized measure of discounted future net cash flows end of year	$ 1,236,983	$ 638,849	$ 486,296

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Note 12 Quarterly Financial Information (Unaudited)

	For Years Ending December 31, 2005	2004
	(In thousands, except per share data)	
First Quarter		
Net revenues(1)	$ 59,471	$ 46,057
Net income	$ 16,035	$ 11,001
Basic net income per share	$ 0.57	$ 0.41
Diluted net income per share	$ 0.56	$ 0.39
Second Quarter		
Net revenues(1)	$ 77,261	$ 58,265
Net income	$ 24,924	$ 14,988
Basic net income per share	$ 0.87	$ 0.55
Diluted net income per share	$ 0.83	$ 0.53
Third Quarter		
Net revenues (1)	$ 71,224	$ 59,904
Net income	$ 23,875	$ 15,639
Basic net income per share	$ 0.83	$ 0.57
Diluted net income per share	$ 0.79	$ 0.55
Fourth Quarter		
Net revenues (1)	$ 52,295	$ 69,279
Net income	$ 5,735	$ 19,368
Basic net income per share	$ 0.20	$ 0.70
Diluted net income per share	$ 0.19	$ 0.67

(1) Net revenues include only oil and gas sales revenue.

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

None.

Item 9A. *Controls and Procedures.*

Evaluation of Disclosure Controls and Procedures.

As of the end of the period covered by this report, our management, including our Chief Executive Officer and our Principal Financial Officer, evaluated the effectiveness of our disclosure controls and procedures as defined in Exchange Act Rule 13a-15(e). Based on that evaluation, our management, including the Chief Executive Officer and the Principal Financial Officer, concluded that our disclosure controls and procedures were effective as of the end of the period covered by this report. Further, during the period covered by this report, there was no significant change in internal controls over financial reporting that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Changes in internal control over financial reporting.

There have been no changes in our internal controls over financial reporting (as defined in rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

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Management s Report on Internal Control over Financial Reporting

The management of Remington Oil and Gas Corporation (the Company) is responsible for establishing and maintaining adequate internal control over financial reporting. The Company s internal control over financial reporting is a process designed under the control of the Company s Chief Executive Officer and the Senior Vice President/Finance to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company s financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2005, management assessed the effectiveness of the Company s internal control over financial reporting based on criteria for effective internal control over financial reporting established in Internal Control Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2005, based on those criteria.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on management s assessment of the effectiveness of the Company s internal control over financial reporting as of December 31, 2005. The report, which expresses unqualified opinions on management s assessment and on the effectiveness of the Company s internal control over financial reporting as of December 31, 2005, is included in this Item under the heading Report of Independent Registered Public Accounting Firm on Internal Control over Financial Reporting.

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

The Board of Directors and Stockholders of
Remington Oil and Gas Corporation:

We have audited management s assessment, included in the accompanying Management s Report on Internal Control Over Financial Reporting, that Remington Oil and Gas Corporation and subsidiaries (the Company), maintained effective internal controls over financial reporting as of December 31, 2005, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). 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 an opinion on management s assessment and an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, management s assessment that the Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as of December 31, 2005 and 2004 and the related consolidated statements of income, stockholders equity and cash flows for each of the three years in the period ended December 31, 2005 of the Company and our report dated March 10, 2006 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Dallas, Texas
March 10, 2006

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

None.

PART III

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

We have adopted a code of ethics (our Code of Business Conduct and Ethics previously filed with the Commission and accessible on our website) that applies to all directors and employees including our Chief Executive Officer, Principal Financial Officer, and Principal Accounting Officer.

The remainder of the information required by Item 10, Directors and Executive Officers of the Registrant, will be included in an amendment to this Form 10-K to be filed no later than 120 days after the end of the fiscal year covered by this Form 10-K.

Item 11. ***Executive Compensation.***

The information required by Item 11, Executive Compensation, will be included in an amendment to this Form 10-K to be filed no later than 120 days after the end of the fiscal year covered by this Form 10-K.

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

The information required by Item 12, Security Ownership of Certain Beneficial Owners and Management, will be included in an amendment to this Form 10-K to be filed no later than 120 days after the end of the fiscal year covered by this Form 10-K.

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

The information required by Item 13, Certain Relationships and Related Transactions, will be included in an amendment to this Form 10-K to be filed no later than 120 days after the end of the fiscal year covered by this Form 10-K.

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

The information required by Item 14, Principal Accountant Fees and Services, will be included in an amendment to this Form 10-K to be filed no later than 120 days after the end of the fiscal year covered by this Form 10-K.

PART IV

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

(a) Documents filed as part of this report:

(1) *Financial Statements included in Item 8:*

(i) Independent Registered Public Accounting Firms Report

(ii) Consolidated Balance Sheets as of December 31, 2005 and 2004

(iii) Consolidated Statements of Income for years ended December 31, 2005, 2004 and 2003

(iv) Consolidated Statement of Stockholders Equity for years ended December 31, 2005, 2004 and 2003

(v) Consolidated Statements of Cash Flows for the years ended December 31, 2005, 2004 and 2003

(vi) Notes to Consolidated Financial Statements

(vii) Supplemental Oil and Natural Gas Information (Unaudited) (Included in the Notes to Consolidated Financial Statements)

(2) *Financial Statement Schedules*

Financial statement schedules are omitted as they are not applicable, or the required information is included in the financial statements or notes thereto.

(3) *Exhibits*

Exhibit Number	Exhibit
2.1****	Agreement and Plan of Merger.
2.2****	Amendment No. 1 to Agreement and Plan of Merger.
3.1###	Restated Certificate of Incorporation of Remington Oil and Gas Corporation.
3.3++	By-Laws as amended of Remington Oil and Gas Corporation.
10.1**	Pension Plan of Remington Oil and Gas as Amended and Restated Effective January 1, 2000.
10.2**	Amendment Number One to the Pension Plan of Remington Oil and Gas Corporation.
10.3##	Amendment Number Two to the Pension Plan of Remington Oil and Gas Corporation.
10.4##	Amendment Number Three to the Pension Plan of Remington Oil and Gas Corporation.
10.5***	Amendment Number Four to the Pension Plan of Remington Oil and Gas Corporation.
10.6+	1997 Stock Option Plan (as amended June 17, 1999 and May 23, 2001).
10.7*	Non-Employee Director Stock Purchase Plan.
10.8##	Form of Employment Agreement effective April 30, 2002, by and between Remington Oil and Gas Corporation and an executive officer.
10.9#	Form of Contingent Stock Grant Agreement Directors.
10.10#	Form of Contingent Stock Grant Agreement Employees.
10.11#	Form of Amendment to Contingent Stock Grant Agreement Directors.
10.12#	Form of Amendment to Contingent Stock Grant Agreement Employees.
10.13###	Remington Oil and Gas Corporation 2004 Stock Incentive Plan.
10.14+++	First Amendment to Remington Oil and Gas Corporation 2004 Stock Incentive Plan.
10.15+++	Form of Restricted Stock Agreement (Employees).
10.16+++	Form of Restricted Stock Agreement (Non-employee Directors).
10.17+++	Remington Oil and Gas Corporation Executive Severance Plan.
10.18+++	Remington Oil and Gas Corporation Employee Severance Plan.
14.1++	Code of Business Conduct and Ethics.
21###	Subsidiaries of Registrant.
23.1####	Consent of Ernst & Young LLP.
23.2####	Consent of Netherland, Sewell & Associates, Inc.
31.1####	Certification of James A. Watt, Chief Executive Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2####	Certification of Frank T. Smith, Jr., Principal Financial Officer, as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1####	Certification of James A. Watt, Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2####	Certification of Frank T. Smith, Jr., Principal Financial Officer, pursuant to 18 U.S.C. Section 1350, as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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* Incorporated by reference to the Company s Form 10-K (file number 1-11516) for the fiscal year ended December 31, 1997 filed with the Commission on March 30, 1998.

Incorporated by reference to the Company s Form 10-K (file number 1-11516) for the fiscal year ended December 31, 2000 filed with the Commission on March 16, 2001.

\+ Incorporated by reference to the Company s Form 10-Q (file number 1-11516) for the fiscal quarter ended September 30, 2001 filed with the Commission on November 9, 2001.

** Incorporated by reference to the Company s Form 10-K (file number 1-11516) for the fiscal year ended December 31, 2001 filed with the Commission on March 21, 2002.

Incorporated by reference to the Company s Form 10-K (file number 1-11516) for the fiscal year ended December 31, 2002, filed with the Commission on March 31, 2003.

++ Incorporated by reference to the Company s Form 10-Q (file number 1-11516) for the fiscal quarter ended June 30, 2003, filed with the Commission on August 11, 2003.

*** Incorporated by reference to the Company s Form 10-K (file number 1-11516) for the fiscal year ended December 31, 2003, filed with the Commission on March 12, 2004.

Incorporated by reference to the Company s Form 10K/A (file number 1-11516) for the fiscal year ended December 31, 2004, filed with the Commission on March 17, 2005.

+++ Incorporated by reference to the Company s Form 10-Q (file number 1-11516) for the fiscal quarter ended March 31, 2005, filed with the Commission on April 29, 2005.

**** Incorporated by reference to the Company s Form 8-K (file number 1-11516) filed with the Commission on January 26, 2006.

Filed herewith

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.

REMINGTON OIL AND GAS CORPORATION

By: /s/ James A. Watt
James A. Watt
Chairman and Chief Executive Officer

Date: March 13, 2006

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

Directors:

/s/ John E. Goble, Jr.	/s/ William E. Greenwood	/s/ Robert P. Murphy
John E. Goble, Jr. Director	William E. Greenwood Director	Robert P. Murphy Director

/s/ David E. Preng	/s/ Thomas W. Rollins	/s/ Alan C. Shapiro
David E. Preng Director	Thomas W. Rollins Director	Alan C. Shapiro Director
/s/ James A. Watt		
James A. Watt Director		

Officers:

/s/ James A. Watt	/s/ Frank T. Smith, Jr.	/s/ Edward V. Howard
James A. Watt Chairman and Chief Executive Officer	Frank T. Smith, Jr. Senior Vice President/Finance (Principal Financial Officer)	Edward V. Howard Vice President/Controller (Principal Accounting Officer)

Date: March 13, 2006