

REMINGTON OIL & GAS CORP

Form 10-K/A

March 17, 2005

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
Form 10-K/A
Amendment No. 1

(Mark One)

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

For the fiscal year ended December 31, 2004

or

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

For the transition period from to

Commission file number 1-11516
Remington Oil and Gas Corporation
(Exact name of registrant as specified in its charter)

Delaware
*(State or other jurisdiction of
incorporation or organization)*

75-2369148
*(I.R.S. employer
identification no.)*

8201 Preston Road, Suite 600, Dallas, Texas
(Address of principal executive offices)

75225-6211
(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 whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☐ No ☐

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

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

The aggregate market value of common stock held by non-affiliates of the registrant as of the last business day of the registrant's most recently completed second fiscal quarter, was \$510,629,613. On March 14, 2005, the number of outstanding shares of common stock, \$0.01 par value, was 28,191,269.

DOCUMENTS INCORPORATED BY REFERENCE

(1) Proxy Statement for Annual Meeting of Stockholders to be held May 25, 2005 Referenced in Part III of this Report.

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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, that 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.

37 employees on December 31, 2004

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.

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

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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.

Risks Involved in Exploration, Development, and Production

Exploration, development, and production operations can be risky. These risks fall into two broad categories. First there is the risk that each time we drill a well, the well will not find oil or gas reserves. Even if a well does find reserves, it is possible that the well will not produce enough oil or gas to return a profit on the amount invested in the well. We try to mitigate these exploration and drilling risks by using 3-D seismic data and other applied technology to identify and define the parameters prior to drilling, although this does not guarantee successful results. Much of our success depends upon the quality of the information used to determine drilling locations and the abilities and experience of our management, technical, and service personnel.

Second is the broad category of operating risks. Operating risks include mechanical failure, title risk, blowouts, environmental pollution, and personal injury. We maintain both general liability insurance and activity specific insurance against major production losses, blowouts, redrilling, and many other operating hazards, including certain pollution risks. Uninsured losses or losses and liabilities that exceed the limits of our insurance could adversely affect our financial condition.

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

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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 Chief Executive Officer and our Chief Operating Officer. We have a lead independent director whose responsibilities are set forth in our corporate governance documents. 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.

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,

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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.

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 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 9 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, 2004, was as follows:

	Undeveloped		Developed	
	Gross	Net	Gross	Net
Offshore	504,622	288,126	244,690	115,242
Onshore	45,800	17,409	28,594	9,630
Total	550,422	305,535	273,284	124,872

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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,

	2005		2006		2007		2008 & Beyond		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Offshore	20,278	11,264	118,240	61,120	100,800	53,424	265,304	162,318	504,622	288,126
Onshore	32,132	6,819	5,230	4,666	3,708	2,490	4,730	3,434	45,800	17,409
Total	52,410	18,083	123,470	65,786	104,508	55,914	270,034	165,752	550,422	305,535

Proved Oil and Gas Reserves

Net proved oil and gas reserves at December 31, 2004, 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	13,102	146,841
Onshore Gulf Coast	3,797	3,858
Total	16,899	150,699

In 2004 our standardized measure of discounted future net cash flows was \$638.8 million. We used the December 31, 2004, West Texas Intermediate posted price of \$40.25 per barrel and a Gulf Coast spot market price of \$6.18 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 properties. 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,		
	2004	2003	2002
	(In thousands)		
Net present value of future cash flows, before income taxes	\$ 868,048	\$ 651,829	\$ 469,252
Future income taxes, discounted at 10%	229,199	165,533	118,210
Standardized measure of discounted future net cash flows	\$ 638,849	\$ 486,296	\$ 351,042

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

	At December 31,					
	2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Oil wells						
Offshore Gulf of Mexico	31	13.13	27	11.05	25	8.67
Onshore Gulf Coast	28	10.87	32	12.25	32	12.89
Total	59	24.00	59	23.30	57	21.56
Gas wells						
Offshore Gulf of Mexico	63	26.02	45	17.37	35	11.19
Onshore Gulf Coast	77	17.43	75	16.36	75	18.52
Total	140	43.45	120	33.73	110	29.71

Our offshore Gulf of Mexico properties account for approximately 83% 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 2004 accounted for approximately 94% of our total oil and gas revenues. We owned varying working interests (5% to 100%) in 144 offshore Gulf of Mexico blocks at December 31, 2004, and currently produce from 51 of these blocks. Five 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 4,000 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.

During 2004 we successfully drilled 17 out of 24 exploratory wells and 5 development wells in the offshore Gulf of Mexico. In addition, we constructed and installed 7 production platforms and 1 subsea completion, and associated pipelines.

Our onshore Gulf Coast area properties are principally located in the State of Mississippi and along the Texas Gulf Coast. In 2004, these properties accounted for approximately 17% of our oil production and approximately 2% of our gas production. We drilled a total of 3 wells on our onshore properties during 2004 and completed 2 wells as

producers. Our working interests in these wells range from 15% to 100%.

Table of Contents**Drilling Activities**

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

For the Years Ended December 31,

	2004				2003				2002			
	Gross		Net		Gross		Net		Gross		Net	
	Prod.	Dry	Prod.	Dry	Prod.	Dry	Prod.	Dry	Prod.	Dry	Prod.	Dry
Exploratory												
Offshore Gulf of Mexico	17	7	9.28	4.15	15	7	8.00	3.46	11	4	5.28	1.66
Onshore Gulf Coast	0	1		0.20	2	1	.41	1.00	5	3	1.66	0.75
Total	17	8	9.28	4.35	17	8	8.41	4.46	16	7	6.94	2.41
Development												
Offshore Gulf of Mexico	5	0	3.25		3	1	1.37	0.50	2		0.66	
Onshore Gulf Coast	2	0	0.80	0.20	2	1	0.25	0.20	1		0.13	
Total	7	0	4.05	0.20	5	2	1.62	0.70	3		0.79	

We had an interest in 1 well (0.75 net) in progress at December 31, 2004, 3 wells (2.10 net) in progress at December 31, 2003, and 1 well (0.25 net) in progress at December 31, 2002.

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 17,000 square feet of office space in Dallas, Texas. However, we have commitments to lease an additional 8,000 square feet in the same building by May 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 security holders during the fourth quarter of 2004.

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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
2005		
First Quarter through March 14, 2005	\$ 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
2003		
Fourth Quarter	20.30	17.25
Third Quarter	19.48	17.09
Second Quarter	19.59	15.32
First Quarter	19.75	16.63

On March 14, 2005, the last reported sales price for our common stock was \$30.89 per share. On that date, there were 548 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.

The following table presents information about our equity compensation plans at December 31, 2004.

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance
	(a)	(b)	(c)
Equity compensation plans approved by stockholders	1,728,439	\$ 11.50	1,926,805
	129,382	\$	

Equity compensation plans
not approved by stockholders

Total	1,857,821	\$	10.70	1,926,805
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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).

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The trigger event was achieved on January 24, 2001.

686,472 shares were awarded. As of December 31, 2004, 516,243 shares have vested, and 40,847 shares have been forfeited. Of the remaining 129,382 shares, 64,691 vested on January 17, 2005, and, except as noted below the remaining 64,691 vest on January 17, 2006.

Each employee and director must remain an employee or director during his/her respective vesting schedule in order to receive the shares, except as noted below.

The vesting period was modified by the Board on October 8, 2004. The modification provides that vesting of any remaining award may now occur in the event that a director retires from the Board or an employee retires from the company prior to age 65 and the retirement date for the individual is within 18 months of the final vesting date. The approved modification was deemed not to be a material amendment of the grant.

In the event of death or a change of control, an employee's or director's shares will fully vest. In the event of the long-term disability of an employee, the employee reaching the retirement age of 65, or the employee retiring within 18 months of the final vesting date, the shares will fully vest.

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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.

	2004	2003	2002	2001(1)	2000(1)
(In thousands, except prices, volumes, and per-share data)					
Financial					
Total revenue	\$ 234,129	\$ 183,052	\$ 104,866	\$ 116,620	\$ 99,661
Net income	\$ 60,996	\$ 42,924	\$ 11,332	\$ 8,344	\$ 45,044
Basic income per share	\$ 2.23	\$ 1.61	\$ 0.45	\$ 0.38	\$ 2.10
Diluted income per share	\$ 2.14	\$ 1.53	\$ 0.42	\$ 0.35	\$ 1.99
Total assets	\$ 453,114	\$ 359,385	\$ 288,993	\$ 240,432	\$ 192,474
8 ¹ / ₄ % convertible subordinated notes	\$	\$	\$	\$	\$ 5,880
Bank debt	\$	\$ 18,000	\$ 37,400	\$ 71,000	\$ 27,428
Stockholders' equity	\$ 313,960	\$ 241,877	\$ 193,660	\$ 125,338	\$ 102,708
Total shares outstanding	27,849	26,912	26,236	22,651	21,564
Cash Flow					
Net cash flow from operations	\$ 188,582	\$ 153,215	\$ 71,420	\$ 99,025	\$ 69,963
Net cash flow (used in) investing	\$ (148,908)	\$ (115,714)	\$ (92,126)	\$ (119,242)	\$ (57,511)
Net cash flow provided by (used in) financing	\$ (12,423)	\$ (21,022)	\$ 16,258	\$ 21,463	\$ 1,323
Operational					
Proved reserves(2)					
Oil (MBbls)	16,899	11,619	13,114	13,865	10,370
Gas (MMcf)	150,699	142,432	124,967	111,920	88,650
Standardized measure of discounted future net cash flows end of year(2)					
	\$ 638,849	\$ 486,296	\$ 351,042	\$ 199,983	\$ 458,649
Average sales price(3)					
Oil (per Bbl)	\$ 39.37	\$ 29.43	\$ 24.27	\$ 23.29	\$ 27.69
Gas (per Mcf)	\$ 5.97	\$ 5.40	\$ 3.35	\$ 4.02	\$ 4.02
Average production (net sales volume)					
Oil (Bbls per day)	4,588	4,863	4,736	3,378	3,234
Gas (Mcf per day)	76,869	66,160	47,804	58,265	34,951

- (1) Financial results for 2001 include a \$13.5 million charge for the final settlement of the Phillips Petroleum litigation, and financial results for 2000 include a \$12.5 million gain on sale of certain South Texas properties.
- (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

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from wells. Revisions can also include changes associated with significant changes in development strategy, oil and gas prices, or production equipment/facility capacity.

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 2004 year-end reserve report we used the December 31, 2004 West Texas Intermediate posted price of \$40.25 per barrel and a Gulf Coast spot market price of \$6.18 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 73 exploration wells, of which 23 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 20% 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 assess 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

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less than its carrying value. Impairments are measured by the amount by which the carrying value exceeds its fair value.

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.

3-D 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.

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 continue to capitalize the drilling costs as an uncompleted well until the earlier to occur of one year from the date drilling is completed or suspended, 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

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or crews or other activities necessary to pursue the targeted reserves or evaluate new or reprocessed seismic and geologic 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.

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.

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 (Mcf) 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 \$375.4 million in oil and gas properties and found 163.2 Bcfe of proved reserves. The following tables reflect our results during the last three years.

	2004	% Increase (Decrease)	2003	% Increase (Decrease)	2002
Production:					
Oil MBbls	1,675	(6)%	1,775	3%	1,729
Gas MMcf	28,057	16%	24,149	38%	17,448
Total MMcfe(1)	38,107	10%	34,799	25%	27,822
Proved reserves:					
Oil MBbls	16,899	45%	11,619	(11)%	13,114
Gas MMcf	150,699	6%	142,432	14%	124,967
Total MMcfe(1)	252,093	19%	212,146	4%	203,651
Operating costs per Mcfe	\$ 0.66	10%	\$ 0.60	3%	\$ 0.58

(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 \$0.58 to \$0.66 or approximately 14% (or 6.67% 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,			Three Years Ended December 31, 2004
	2004	2003	2002	
	(In thousands)			
Unproved acquisition costs	\$ 10,878	\$ 2,370	\$ 4,215	\$ 17,463
Proved acquisition costs	1,554	1,466		3,020
Exploration	80,970	54,138	45,381	180,489
Development	65,080	58,475	50,904	174,459
Asset retirement obligation	4,267	9,963		14,230
 Total capital and exploration costs	 \$ 162,749	 \$ 126,412	 \$ 100,500	 \$ 389,661
 Proved reserves (Mcfe)				
Beginning total proved reserves	212,146	203,651	195,110	195,110
Revisions of previous estimates	(1,629)	(7,932)	(7,847)	(17,408)
Extensions and discoveries	79,683	44,698	49,671	174,052
Reserves purchased		6,528		6,528
 Total proved reserve additions	 78,054	 43,294	 41,824	 163,172
 Reserves sold				
Production	(38,107)	(34,799)	(27,822)	100,728
 Ending total proved reserves	 252,093	 212,146	 203,651	 252,093

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 under Liquidity and Capital Resources.

Liquidity and Capital Resources

Cash flow provided by operations for the year ended December 31, 2004, increased by \$35.4 million, or 23%, compared to the prior year primarily due to a 9.5% increase in production and an \$0.88/ Mcfe, or 16.8% increase in oil and gas prices. We expect our cash flow provided by operations for 2005 to increase because of higher projected production from new properties, combined with oil and gas prices consistent with 2004 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 Hurricane Ivan last September.

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. Currently we have no such arrangements in place. See additional discussion under Commodity Price Risk in Item 7A Quantitative and Qualitative Disclosures about Market Risk.

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Changes in our working capital accounts from 2003 to 2004 include an increase in our accounts receivable (a decrease in our cash flow provided by operations) due to higher oil and gas prices, increased production and increased balances due from our joint interest participants as a result of increased operating activities (drilling wells and facilities construction) at year end. Due to the increase in operating activities our accounts payable balance increased by \$11.0 million which increased our cash flow from operations. Cash flow provided by operations also decreased due to an increase in prepaid expenses and other current assets primarily because of an increase in prepaid drilling and facility costs.

We incurred capital and exploration expenditures totaling \$148.9 million during 2004. The capital expenditures included \$12.4 million for leasehold acquisition, \$81.0 million for exploration costs, \$65.1 million for development costs, including platform and facilities construction and \$4.3 million for asset retirement costs. During the year we built and installed 2 offshore platforms and facilities. In addition, in 2004 we drilled 25 exploration wells (24 offshore) and 7 development wells (5 offshore) and had 1 well 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 \$144.6 million for capital and exploration expenditures in 2005. Our 2005 capital and exploration budget includes \$78.8 million for 28 exploratory wells. We project that we will spend \$71.5 million on 24 wells in the Gulf of Mexico and \$7.3 million on 4 onshore wells in South Texas and Mississippi. The budget also includes \$41.2 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 2005 exploration and development program. The remaining \$24.5 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. If we continue at our historical success rates, the 2005 capital expenditures are estimated to be \$200 million to \$225 million. 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.

Effective May 1, 2004, we agreed with our lenders to maintain our borrowing base at \$100.0 million. As of December 31, 2004, we had nothing borrowed under the facility. The banks review the borrowing base semi-annually and, at their discretion, may decrease or propose an increase to the borrowing base relative to a re-determined estimate of proved oil and gas reserves. Our oil and gas properties are pledged as collateral for the line of credit. Additionally, we have agreed not to pay dividends. The most significant financial covenants in the line of credit include maintaining a minimum current ratio (as defined in the credit agreement) of 1.0 to 1.0, a minimum tangible net worth of \$85.0 million plus 50% of net income (accumulated from the inception of the agreement) and 100% of any non-redeemable preferred or common stock offerings, and interest coverage of 3.0 to 1.0. We are currently in compliance with these financial covenants. If we do not comply with these covenants on a continuing basis, the lenders have the right to refuse to advance additional funds under the facility and/or declare any outstanding principal and interest immediately due and payable.

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/or warrants. The SEC declared the shelf registration statement effective December 18, 2003. We have not drawn on the shelf offering. Generally, the shelf is effective for two years from the effective date.

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The following table summarizes our contractual obligations and commercial commitments as of December 31, 2004.

	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)	\$ 553	\$ 425	\$ 128	\$	\$
Other(1)	11,658	3,718	6,000	1,940	
Office lease	4,709	489	1,316	1,358	1,546
Total	\$ 16,920	\$ 4,632	\$ 7,444	\$ 3,298	\$ 1,546

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

On December 31, 2004, our current assets exceeded our current liabilities by \$44.1 million. Our current ratio was 1.64 to 1.00.

Results of Operations

In 2004, we achieved net income totaling \$61.0 million or \$2.23 basic income per share, and \$2.14 diluted income per share, compared to net income of \$42.9 million or \$1.61 basic income per share and \$1.53 diluted income per share in 2003. The increase in net income resulted primarily from increased oil and gas production and sales prices. In addition to oil and gas production and sales prices, 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.

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, 2004, 2003, and 2002.

	2004	% Increase (Decrease)	2003	% Increase (Decrease)	2002
(Revenue information in thousands)					
Oil volume (MBbls)	1,675	(6)%	1,775	3%	1,729
Oil revenue	\$ 65,941	26%	\$ 52,233	24%	\$ 41,969
Price per Bbl	\$ 39.37	34%	\$ 29.43	21%	\$ 24.27
Increase in oil revenue due to:					
Change in prices	\$ 17,644		\$ 8,922		
Change in production volume	(3,936)		1,342		
Total increase in oil revenue	\$ 13,708		\$ 10,264		

Gas volume (MMcf)	28,057	16%	24,149	38%	17,448
Gas revenue	\$ 167,564	29%	\$ 130,346	123%	\$ 58,412
Price per Mcf	\$ 5.97	11%	\$ 5.40	61%	\$ 3.35
Increase in gas revenue due to:					
Change in prices	\$ 13,765		\$ 35,768		
Change in production volume	23,453		36,166		
Total increase in gas revenue	\$ 37,218		\$ 71,934		

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Oil sales revenue during 2004 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. During 2003, oil sales revenue increased by \$10.3 million, or 24%, compared to 2002 because oil production increased by 46,000 barrels, or 3%, and average oil prices increased by \$5.16 or 21%. The increase in oil production came primarily from new properties in the offshore Gulf of Mexico partially offset by natural depletion of the existing producing properties in the Gulf Coast area and the sale of certain properties in South Texas in April 2002.

Gas sales revenue during 2004 increased by \$37.2 million or 29% compared to 2003 because of higher average gas prices and increased production. Average gas prices increased 11% from \$5.40 per Mcf in 2003 to \$5.97 per Mcf in 2004, while production increased by 3.9 Bcf, or 16%, to 28.1 Bcf primarily because of gas production from new properties in the offshore Gulf of Mexico. During 2003, gas sales revenue increased by \$71.9 million, or 123% because of higher average gas prices and production. Average gas prices climbed from \$3.35 per Mcf in 2002 to \$5.40 per Mcf, or 61%, in 2003. Gas production increased by 6.7 Bcf, or 38%, primarily because of higher gas production from the offshore Gulf of Mexico.

During 2002, we sold certain South Texas properties at a \$4.1 million gain. This gain in 2002 accounts for the decrease in other income during 2003 when compared to 2002.

Operating Costs and Expenses

Total operating costs during 2004 increased by \$4.1 million, or 20%, compared to 2003, due to the increase in the number of operating properties. However, operating costs per Mcfe increased by only \$0.06, or 10%, to \$0.66 during 2004. The following table presents the major components of our operating costs and operating costs per Mcfe.

Years Ending December 31,

	2004		2003		2002	
	Total	Per Mcfe	Total	Per Mcfe	Total	Per Mcfe
(In thousands, except per Mcfe amounts)						
Direct operating expense	\$ 18,406	\$ 0.49	\$ 15,709	\$ 0.45	\$ 11,664	\$ 0.42
Overhead & company labor	536	0.01	346	0.01	266	0.01
Workovers	2,525	0.07	1,597	0.04	1,434	0.05
Ad valorem taxes	34	0.00	74	0.00	28	0.00
Production taxes	871	0.02	870	0.03	680	0.02
Transportation	2,641	0.07	2,314	0.07	2,078	0.08
Total	\$ 25,013	\$ 0.66	\$ 20,910	\$ 0.60	\$ 16,150	\$ 0.58

Exploration Expenses Successful-Efforts Method of Accounting

During 2004, exploration expenses decreased by \$2.9 million, or 11%, compared to 2003 primarily because of an \$11.2 million (46.7%) decrease in dry hole costs. Exploration expenses for 2003 increased by \$9.8 million, or 63%, because of increased dry hole costs compared to 2002 and a \$628,000 increase in seismic expenses over 2002. During the last three years we have drilled 73 exploration wells, of which 23 considered dry holes, resulting in a 68% success ratio on exploratory wells. Our dry hole costs charged to expense during this period totaled \$51.6 million out of total exploratory drilling costs of \$180.5 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 2004 increased by \$17.1 million, or 31%, compared to the prior year. On a per Mcfe basis, depreciation, depletion and amortization per Mcfe increased to \$1.91 in 2004 from \$1.60 in 2003 reflecting the increased costs for finding reserves in the Gulf of Mexico. Depreciation, depletion and amortization expense increased by

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\$17.2 million, or 45% for the year ended December 31, 2003, compared to the prior year, and depreciation, depletion and amortization per Mcfe increased to \$1.60 from \$1.38 in 2002 reflecting the increased cost of finding reserves in the Gulf of Mexico.

Asset Retirement Obligations

We adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations (SFAS 143), 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.

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 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 years ended December 31, 2003 and 2002, as if we had adopted the provisions of SFAS 143 on January 1, 2001, including aggregate pro forma asset retirement obligations on that date:

	Years Ended December 31,	
	2003	2002
	(In thousands, except per-share amounts)	
Net income, as reported	\$ 42,924	\$ 11,332
Pro forma adjustment to reflect retroactive adoption of SFAS 143	34	(85)
Pro forma net income	\$ 42,958	\$ 11,247
Net income per share:		
Basic as reported	\$ 1.61	\$ 0.45

Basic	pro forma	\$	1.61	\$	0.44
Diluted	as reported	\$	1.53	\$	0.42
Diluted	pro forma	\$	1.53	\$	0.41

Table of Contents***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,		
	2004	2003	2002
	(In thousands)		
Unproved properties	\$ 1,130	\$ 1,136	\$ 1,640
Proved properties	9,746	3,311	6,441
Total impairment expense	\$ 10,876	\$ 4,447	\$ 8,081

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. The properties impaired in 2004 primarily consisted of properties in the Gulf of Mexico which totaled \$4.2 million and properties in the onshore Gulf Coast totaling \$5.5 million, and in 2003 included two properties in the Gulf of Mexico which totaled \$2.4 million and one in the onshore Gulf Coast which totaled \$855,000. During 2002, we impaired two proved properties in the offshore Gulf of Mexico that accounted for \$3.5 million and two proved properties in the onshore Gulf Coast that accounted for \$2.9 million. The impairments resulted primarily from wells depleting sooner than originally estimated or capital costs in excess of those anticipated.

General and Administrative Expenses

General and administrative expenses during 2004 decreased by \$355,000, or 4% compared to 2003. General and administrative expenses decreased by \$0.03 per Mcfe to \$0.21 in 2004 from \$0.24 in 2003. General and administrative expense in 2003 increased by \$1.5 million. Stock based compensation expense which is included in general and administrative expense totaled \$1.4 million in 2004, \$1.6 million in 2003 and \$1.6 million in 2002.

Interest and Financing Expense

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

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Income Taxes

During 2004, income taxes increased by \$9.3 million compared to 2003 and increased by \$17.5 million during 2003 compared to 2002 as a result of increased income before taxes. The effective tax rate increased slightly in 2003 due to an increase in the provision for deferred state income taxes.

New Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board 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 July 1, 2005, 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 July 1, 2005, 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 \$4.1 million during the year ended December 31, 2004.

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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. We currently have no such arrangements in place.

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Item 8. *Financial Statements and Supplementary Data.*

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<u>Consolidated Statements of Stockholders' Equity for 2004, 2003, and 2002</u>	28
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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, 2004 and 2003, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2004. 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 and subsidiaries at December 31, 2004 and 2003, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, 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, 2004, 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 14, 2005 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 14, 2005

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REMINGTON OIL AND GAS CORPORATION
CONSOLIDATED BALANCE SHEETS

	At December 31,	
	2004	2003
	(In thousands, except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	\$ 58,659	\$ 31,408
Accounts receivable	49,582	43,004
Prepaid expenses and other current assets	5,199	2,846
Total current assets	113,440	77,258
Properties		
Oil and gas properties (successful-efforts method)	744,215	609,599
Other properties	3,145	3,450
Accumulated depreciation, depletion and amortization	(409,591)	(333,011)
Total properties	337,769	280,038
Other assets		
Other assets	1,905	2,089
Total other assets	1,905	2,089
Total assets	\$ 453,114	\$ 359,385
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued expenses	\$ 69,339	\$ 58,311
Total current liabilities	69,339	58,311
Long-term liabilities		
Notes payable		18,000
Asset retirement obligations	16,030	12,446
Deferred income taxes	53,785	28,751
Total long-term liabilities	69,815	59,197
Total liabilities	139,154	117,508
Commitments and contingencies (Note 4)		
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, 27,883,698 shares issued and 27,849,339 shares outstanding in 2004, 26,946,768 shares issued and 26,912,409 shares outstanding in 2003		
	279	269
Additional paid-in capital	132,334	120,925
Restricted common stock	6,749	3,156
Unearned compensation	(5,593)	(1,668)
Retained earnings	180,191	119,195
Total stockholders' equity	313,960	241,877
Total liabilities and stockholders' equity	\$ 453,114	\$ 359,385

See accompanying Notes to Consolidated Financial Statements.

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REMINGTON OIL AND GAS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2004	2003	2002
	(In thousands, except per-share amounts)		
Revenues			
Gas sales	\$ 167,564	\$ 130,346	\$ 58,412
Oil sales	65,941	52,233	41,969
Interest income	349	161	198
Gain on sale of assets and other income	275	312	4,287
Total revenues	234,129	183,052	104,866
Costs and expenses			
Operating costs and expenses	25,013	20,910	16,150
Exploration expenses	22,551	25,416	15,623
Depreciation, depletion, and amortization	72,810	55,694	38,528
Impairment of oil and gas properties	10,876	4,447	8,081
General and administrative	8,053	8,408	6,912
Interest and financing expense	894	1,635	2,145
Total costs and expenses	140,197	116,510	87,439
Income before taxes	93,932	66,542	17,427
Income taxes	32,936	23,618	6,095
Net income	\$ 60,996	\$ 42,924	\$ 11,332
Basic income per share	\$ 2.23	\$ 1.61	\$ 0.45
Diluted income per share	\$ 2.14	\$ 1.53	\$ 0.42

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, 2001	\$ 227	\$ 56,698	\$ 8,055	\$ (4,581)	\$	\$ 64,939
Net income						11,332
Amortization of unearned compensation				1,389		
Common stock issued	36	57,375	(2,587)		(977)	
Tax benefit from exercise of stock options		1,754				
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

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,		
	2004	2003	2002
	(In thousands)		
Cash flow provided by operations			
Net income	\$ 60,996	\$ 42,924	\$ 11,332
Adjustments to reconcile net income			
Depreciation, depletion, and amortization	72,810	55,694	38,528
Deferred income tax expense	25,034	23,443	6,095
Amortization of deferred finance charges	183	207	228
Impairment of oil and gas properties	10,876	4,447	8,081
Dry hole costs	12,787	23,993	14,828
Cash paid for dismantlement and restoration liability	(1,712)	(1,631)	(247)
Stock based compensation	1,427	1,565	1,609
Tax benefit from exercise of stock options	4,083		
Gain on sale of properties			(4,095)
Changes in working capital			
(Increase) in accounts receivable	(6,570)	(10,483)	(13,099)
Decrease (increase) in prepaid expenses and other current assets	(2,360)	2,313	(5,131)
Increase in accounts payable and accrued expenses	11,028	10,743	13,291
Net cash flow provided by operations	188,582	153,215	71,420
Cash from investing activities			
Payments for capital expenditures	(148,908)	(115,714)	(99,865)
Proceeds from property sales			7,739
Net cash (used in) investing activities	(148,908)	(115,714)	(92,126)
Cash from financing activities			
Proceeds from notes payable			17,000
Payments on notes payable and other long-term payables	(18,000)	(22,573)	(54,393)
Purchase common stock	(645)	(808)	(977)
Commitment fee on line of credit		(294)	
Common stock issued	6,222	2,653	54,628
Net cash provided by (used in) financing activities	(12,423)	(21,022)	16,258
Net increase (decrease) in cash and cash equivalents	27,251	16,479	(4,448)
Cash and cash equivalents at beginning of period	31,408	14,929	19,377
Cash and cash equivalents at end of period	\$ 58,659	\$ 31,408	\$ 14,929
Cash paid for interest	\$ 948	\$ 1,702	\$ 2,552

Cash paid for taxes	\$	580	\$	175	\$
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See accompanying Notes to Consolidated Financial Statements.

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**REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

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. We make certain reclassifications to prior year financial statements in order to conform to the current year presentation.

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. Substantially all of our cash and cash equivalents at December 31, 2004 and 2003 exceeded the \$100,000 federally insured limit for amounts deposited at financial institutions. At December 31, 2004, 3 companies accounted for approximately 59% of our total accounts receivable, and at December 31, 2003, 3 companies accounted for approximately 65% of our total accounts receivable. Oil and gas are fungible commodities in high demand from numerous customers; however, during 2004 we sold oil and gas to 4 major customers who accounted for 27%, 20%, 18% and 12% of our total revenues. The sale of oil and gas to 4 major customers accounted for 17%, 16%, 14% and 13% of our total oil and gas revenues in 2003. 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.

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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 licenses 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 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 continue to capitalize the drilling costs as an uncompleted well until the earlier to occur of one year from the date drilling is completed or suspended, 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

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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

complete drilling, we will charge the capitalized costs to dry hole expense. Total capitalized exploratory drilling costs were \$12.8 million for the year ended December 31, 2004, and \$7.8 million for the year ended December 31, 2003.

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 the December 31, 2004 and 2003.

		At December 31,		
	Well2004	Cost	Well2003	Cost
(In thousands, except well numbers)				
Exploration wells requiring major capital expenditures		\$		\$
Exploration wells not requiring major capital expenditures and capitalized for more than one year	1	4,445		
Total	1	\$ 4,445		\$

At December 31, 2004, we are carrying the costs of three exploratory wells that do not have proved reserves associated with them. Of the three, two wells are salvaged well bores that we will reenter and continue exploration drilling. Only one of these wells has been carried for more than one year. It did not originally reach the drilling target due to mechanical failure. We are waiting for additional reprocessed seismic data to further define the drilling target. The remaining well is waiting for completion of infrastructure on a contiguous block.

We do not believe that the application of the proposed FASB Staff Position No. FAS 19-a of the Financial Accounting Standards Board would have changed our results of operations for any of the three years ending December 31, 2004, 2003 and 2002. The following table presents exploratory costs deferred by year as of December 31, 2004.

At December 31, 2004				
Costs Deferred by Period				
		Less		2 or
		than		more
	Total	1 Year	1 Year	Years
	(In thousands)			
Capitalized exploration costs	\$ 12,777	\$ 8,332	\$ 4,445	\$

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,

	2004		2003		2002	
	Wells	Cost	Wells	Cost	Wells	Cost
(In thousands, except well numbers)						
Beginning Balance	2	\$ 7,778		\$	2	\$ 4,692
Reclassified to wells & facilities					(1)	(1,510)
Dry hole expense		(2,861)			(1)	(3,182)
Additions to capitalized costs	1	7,860	2	7,778		
Total	3	\$ 12,777	2	\$ 7,778		\$

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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other Assets

Other assets include the long-term portion of prepaid pension expenses (see Note 7 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 \$385,000 at December 31, 2004, and \$376,000 at December 31, 2003, 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.

Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses were as follows:

	At December 31,	
	2004	2003
	(In thousands)	
Accounts payable – trade	\$ 59,656	\$ 41,330
Income taxes payable	3,240	
Advance billings	1,970	11,266
Royalties and other revenue payable	4,473	5,670
Total accounts payable and accrued expenses	\$ 69,339	\$ 58,266

Oil and Gas Revenues

When oil and gas is produced, we sell it immediately. Consequently, we recognize oil and gas revenue 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, 2004, 2003, and 2002, we incurred transportation costs totaling \$2.6 million, \$2.3 million, and \$2.1 million, respectively.

Stock Options

In December 2002, the Financial Accounting Standards Board 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 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).

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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Through June 30, 2005, we will continue to 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.

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,		
	2004	2003	2002
	(In thousands, except per-share amounts)		
As reported:			
Net income	\$ 60,996	\$ 42,924	\$ 11,332
Basic income per share	\$ 2.23	\$ 1.61	\$ 0.45
Diluted income per share	\$ 2.14	\$ 1.53	\$ 0.42
Stock based compensation (net of tax at statutory rate of 35%) included in net income as reported	\$ 928	\$ 1,017	\$ 1,046
Stock based compensation (net of tax at statutory rate of 35%) if using the fair value method as applied to all awards	\$ 6,711	\$ 3,146	\$ 2,531
Pro forma (if using the fair value method applied to all awards):			
Net income	\$ 55,213	\$ 40,795	\$ 9,847
Basic income per share	\$ 2.02	\$ 1.53	\$ 0.39
Diluted income per share	\$ 1.94	\$ 1.46	\$ 0.36
Weighted average shares used in computation			
Basic	27,408	26,628	25,294
Diluted	28,441	27,987	27,122

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 are vested at December 31, 2004.

The fair value of each option grant for the years ended December 31, 2004, 2003, and 2002, 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	2002
Expected life (years)	7	7	10
Interest rate	4.07%	3.73%	4.17%
Volatility	63.70%	65.27%	61.62%

Dividend yield	0%	0%	0%
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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.

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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Income Taxes

Income tax expense or benefit includes both current income taxes and deferred income taxes. Current income tax expense or benefit equals the amount expected to be calculated on our income tax return for that year. Deferred income tax expense or benefit equals the change in the net deferred income tax asset or liability from the beginning of the year plus the tax benefit derived from the exercise of employee stock options. 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 Financial Accounting Standards Board issued FASB 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 Provided 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. Pursuant to the AJCA, we will not be able to claim this tax benefit until the first quarter of fiscal 2006. We do not expect the adoption of these new tax provisions to have a material impact on our consolidated financial position, results of operations or cash flows.

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,		
	2004	2003	2002
	(In thousands, except per-share amounts)		
Net income available for basic income per share	\$ 60,996	\$ 42,924	\$ 11,332
Basic income per share	\$ 2.23	\$ 1.61	\$ 0.45
Diluted income per share	\$ 2.14	\$ 1.53	\$ 0.42
Weighted average common shares for basic income per share	27,408	26,628	25,294
Dilutive stock options outstanding (treasury stock method)	837	1,099	1,378
Common stock grant	196	260	450
Total common shares for diluted income per share	28,441	27,987	27,122

Non-dilutive stock options outstanding	749	1,235	1,174
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**REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Adopted and New Accounting Policies

In December 2004, the Financial Accounting Standards Board 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 Bulletin 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 July 1, 2005, 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 July 1, 2005, 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. 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 \$4.1 million during the year ended December 31, 2004.

We adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143), effective January 1, 2003. The statement requires that we estimate the fair value of 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.

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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Prior to this adoption, 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 years ended December 31, 2003 and 2002, as if we had adopted the provisions of SFAS 143 on January 1, 2001, including aggregate pro forma asset retirement obligations on that date:

	Years Ended December 31,	
	2003	2002
	(In thousands, except per-share amounts)	
Net income, as reported	\$ 42,924	\$ 11,332
Pro forma adjustment to reflect retroactive adoption of SFAS 143	34	(85)
Pro forma net income	\$ 42,958	\$ 11,247
Net income per share:		
Basic as reported	\$ 1.61	\$ 0.45
Basic pro forma	\$ 1.61	\$ 0.44
Diluted as reported	\$ 1.53	\$ 0.42
Diluted pro forma	\$ 1.53	\$ 0.41

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,					
	2004			2003		
	Proved	Unproved	Total	Proved	Unproved	Total
	(In thousands)					
Oil and gas properties	\$ 717,316	\$ 26,899	\$ 744,215	\$ 590,257	\$ 19,342	\$ 609,599
Accumulated depreciation, depletion and amortization	(407,134)		(407,134)	(330,432)		(330,432)
	\$ 310,182	\$ 26,899	\$ 337,081	\$ 259,825	\$ 19,342	\$ 279,167

Net oil and gas
properties

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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

For Years Ended December 31,			
	2004	2003	2002
	(In thousands)		
Unproved acquisition costs	\$ 10,878	\$ 2,370	\$ 4,215
Proved acquisition costs	1,554	1,466	
Exploration costs	80,970	54,138	45,381
Development costs	65,080	58,475	50,904
Discounted estimate of future asset retirement costs	4,267	9,963	
Total	\$ 162,749	\$ 126,412	\$ 100,500

We recognized impairment expenses shown in the table below:

For Years Ended December 31,			
	2004	2003	2002
	(In thousands)		
Unproved properties	\$ 1,130	\$ 1,136	\$ 1,640
Proved properties	9,746	3,311	6,441
Total impairment expense	\$ 10,876	\$ 4,447	\$ 8,081

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. The proved properties impaired during 2004 included two properties in the Gulf of Mexico which totaled \$4.2 million and two onshore Gulf Coast properties which totaled \$5.5 million. The proved properties impaired in 2003 primarily consisted of two properties in the Gulf of Mexico which totaled \$2.4 million and one property in the onshore Gulf Coast, and the proved properties impaired in 2002 included two properties in the Gulf of Mexico which totaled \$3.5 million and two in the onshore Gulf Coast which totaled \$2.9 million. The impairments resulted primarily from wells depleting sooner than originally estimated or capital costs in excess of those anticipated.

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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes our asset retirement obligation. The year ended December 31, 2002, and 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,		
	2004	2003	2002
	(Unaudited in thousands)		
Beginning of period	\$ 12,446	\$ 11,807	\$ 8,305
New properties and changes in estimates	4,267	1,393	3,114
Settlement of liabilities	(1,712)	(1,631)	(247)
Loss on settlement of liabilities	21		
Accretion of liability	1,008	877	635
End of period	\$ 16,030	\$ 12,446	\$ 11,807

Note 3 Notes Payable and Other Long-Term Payables**Bank Credit Facility**

As of December 31, 2004, our amended credit facility of \$150.0 million had a borrowing base of \$100.0 million. The following schedule reflects certain information about the line of credit for the last two years.

	At December 31,	
	2004	2003
	(In thousands)	
Borrowing base	\$ 100,000	\$ 100,000
Outstanding balance		18,000
Available amount	\$ 100,000	\$ 82,000

We pledged our oil and gas properties as collateral for this line of credit. We accrue and pay interest at varying rates based on premiums ranging from 1.5 to 2.25 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, if any, only is payable quarterly through May 3, 2006, 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 maintaining a minimum current ratio (as defined in the credit agreement) of 1.0 to 1.0, a minimum tangible net worth of \$85.0 million plus 50% of net income (accumulated from the inception of the agreement) and 100% of any non-redeemable preferred or common stock offerings, and interest coverage of 3.0 to 1.0. We are 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.

Fair Value of Indebtedness

We estimate that the fair value of our long-term indebtedness, including the current maturities of such obligations, was approximately \$18.0 million at December 31, 2003. We based the fair value on current rates available for our bank debt. The book value of our other long-term indebtedness approximates fair value.

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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 4 Commitments and Contingent Liabilities

We currently lease approximately 17,000 square feet of office space in Dallas, Texas. However, we have commitments to lease an additional 8,000 square feet by May 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)
2002	\$ 441
2003	\$ 441
2004	\$ 441
2005	\$ 489
2006	\$ 644
2007	\$ 672
2008	\$ 678
2009	\$ 680
After 2009	\$ 1,546

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 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 5 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 preferred stock.

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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 6 Stock Based Compensation Expense. Dividend payments are currently prohibited by our line of credit agreement.

Note 6 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, 2004, 2003, and 2002, and changes during the years ending on those dates is presented below:

	At December 31,					
	2004		2003		2002	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	2,334,333	\$ 10.93	2,552,219	\$ 8.68	2,598,700	\$ 6.72
Granted	30,000	23.24	360,000	18.66	400,000	17.20
Exercised	(835,894)	7.58	(559,553)	5.44	(440,978)	4.87
Forfeited			(18,333)	16.82	(5,503)	9.04
Outstanding at end of year	1,528,439	\$ 13.00	2,334,333	\$ 10.93	2,552,219	\$ 8.68
Options exercisable at year-end	1,528,439	\$ 13.00	1,592,667	\$ 7.81	1,613,554	\$ 6.54
Weighted-average fair value of options granted during the year		\$ 15.23		\$ 12.33		\$ 12.64

The options outstanding at December 31, 2004, have a weighted-average remaining contractual life of 6.33 years and exercise prices ranging from \$3.125 to \$23.89 per share. A breakdown of the options outstanding at December 31, 2004, 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
\$3.13 - \$4.25	279,558	\$ 3.80	5.16	279,558	\$ 3.80
\$5.38 - \$6.94	146,430	\$ 6.39	2.72	146,430	\$ 6.39
\$9.00 - \$15.32	397,682	\$ 12.77	5.44	397,682	\$ 12.77
\$16.73 - \$23.89	704,769	\$ 18.16	8.05	704,769	\$ 18.16

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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. 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. The shares under this grant vest one-fifth each October of 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 \$5.2 million as restricted common stock and as 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 that conforms to the vesting schedule of the shares. During each of the years ended December 31, 2004, 2003 and 2002, we amortized \$1.3 million, \$1.3 million and \$1.4 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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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A summary of all stock grants as of December 31, 2004, 2003 and 2002, and changes during the years ending on those dates is presented below:

	At December 31,					
	2004		2003		2002	
	Shares	Weighted Average Price	Shares	Weighted Average Price	Shares	Weighted Average Price
Outstanding at beginning of period	259,636	\$ 12.16	447,192	\$ 12.16	662,592	\$ 12.16
Grants	200,000	25.88				
Exercised	(130,254)	12.16	(173,228)	12.16	(212,761)	12.16
Forfeited			(14,328)	12.16	(2,639)	12.16
Outstanding at end of year	329,382	\$ 20.49	259,636	\$ 12.16	447,192	\$ 12.16

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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 7 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.

	At December 31,	
	2004	2003
	(In thousands)	
Reconciliation of the change in projected benefit obligation		
Beginning projected benefit obligation	\$ 6,032	\$ 4,833
Service cost	591	415
Interest cost	373	322
Amendments		42
Actuarial loss	298	633
Benefits paid	(211)	(213)
Ending projected benefit obligation	\$ 7,083	\$ 6,032
Reconciliation of the change in plan assets		
Beginning market value	\$ 5,989	\$ 4,506
Actual return on plan assets	574	846
Employer contributions	174	850
Benefit payments	(211)	(213)
Ending market value	\$ 6,526	\$ 5,989
Funded status and amounts recognized in the balance sheet		
Excess of assets over projected benefit obligation	\$ (557)	\$ (43)
Unrecognized net actuarial loss	2,498	2,458
Unrecognized prior service costs	36	39
Adjusted net prepaid benefit cost recognized	\$ 1,977	\$ 2,454
Accumulated benefit obligation	\$ 5,907	\$ 5,077
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 contributions to the pension plans in 2005.

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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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)
2005	\$ 204
2006	999
2007	193
2008	187
2009	850
2010 through 2014	1,637

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

	For Years Ended December 31,		
	2004	2003	2002
	(In thousands)		
Components of net periodic pension cost			
Service cost	\$ 591	\$ 415	\$ 291
Interest cost on projected benefit obligation	373	322	263
Expected return on plan assets	(471)	(352)	(219)
Recognized net actuarial loss	155	154	62
Amortization of prior service costs	3	3	
Net periodic pension cost	\$ 651	\$ 542	\$ 397

Assumptions used to determine net periodic pension costs

Discount rate	6.00%	6.50%	7.25%
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.

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, 2004, was \$6.4 million and the aggregate fair value of plan assets was \$5.7 million. On December 31, 2004, Remington had a prepaid benefit cost of \$1.6 million. CKB Petroleum's aggregate projected benefit obligation at December 31, 2004, was \$676,000 and the aggregate fair value of plan assets was \$841,000. On December 31, 2004, CKB Petroleum had a prepaid benefit cost of \$414,000.

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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	At December 31,	
	2004	2003
Asset category		
Equity securities	71.2%	63.6%
Debt securities	19.7%	20.6%
Money funds	9.1%	15.8%
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

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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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 8 Income Taxes

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

	For Years Ended December 31,		
	2004	2003	2002
	(In thousands)		
Current			
Federal	\$ 7,755	\$ 175	\$
State	147		
	7,902	175	
Deferred			
Federal	24,688	23,113	6,095
State	346	330	
	25,034	23,443	6,095
Total income tax expense	\$ 32,936	\$ 23,618	\$ 6,095

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,		
	2004	2003	2002
	(In thousands)		
Federal income tax expense at statutory rate	\$ 32,876	\$ 23,290	\$ 6,095
State income tax expense	493	328	
Other	(433)		
Total income tax expense	\$ 32,936	\$ 23,618	\$ 6,095

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

	At December 31,	
	2004	2003
	(In thousands)	
Deferred tax liabilities		
Oil and gas properties	\$ (54,611)	\$ (35,429)

Total deferred tax liabilities	(54,611)	(35,429)
Deferred tax assets		
Federal net operating loss carryforwards		4,130
Federal alternative minimum tax credit carry forwards		479
Asset retirement obligation	684	1,980
Other assets	142	89
Total deferred tax assets	826	6,678
Net deferred tax (liability)	\$ (53,785)	\$ (28,751)

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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 9 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, 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,					
	2004		2003		2002	
	Oil Bbls	Gas Mcf	Oil Bbls	Gas Mcf	Oil Bbls	Gas Mcf
	(In thousands)					
Beginning of period	11,619	142,432	13,114	124,967	13,865	111,920
Revisions of previous estimates	1,862	(12,801)	(363)	(5,754)	(596)	(4,271)
Extensions, discoveries and other	5,093	49,125	337	42,676	1,678	39,603
Reserves purchased			306	4,692		
Reserves sold					(104)	(4,837)
Production	(1,675)	(28,057)	(1,775)	(24,149)	(1,729)	(17,448)
End of period	16,899	150,699	11,619	142,432	13,114	124,967
Proved developed reserves	6,858	89,376	7,071	76,475	7,977	71,481

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 Gulf Coast spot market prices per MMBtu adjusted by property for energy

content, quality, transportation fees, and regional price differentials.

	Years Ended December 31,		
	2004	2003	2002
West Texas Intermediate posted price (per barrel)	\$ 40.25	\$ 29.25	\$ 28.00
Gulf Coast spot market price (per MMBtu)	\$ 6.18	\$ 5.97	\$ 4.74

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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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,		
	2004	2003	2002
	(In thousands)		
Oil and gas revenues	\$ 1,581,927	\$ 1,206,775	\$ 946,813
Production costs	(192,761)	(165,733)	(150,084)
Development, dismantlement and abandonment costs(1)	(150,596)	(140,175)	(116,944)
Income tax expense	(323,492)	(223,929)	(166,864)
Net cash flow	915,078	676,938	512,921
10% annual discount	(276,229)	(190,642)	(161,879)
Standardized measure of discounted future net cash flows	\$ 638,849	\$ 486,296	\$ 351,042

- (1) Based on our Netherland, Sewell & Associates audited reserve report for January 1, 2005, we estimate that the amount of capital required to convert proved undeveloped reserves to proved developed reserves will be \$104.0 million of the \$125.0 million of future development costs, including \$55.9 million in 2005, \$15.1 million in 2006 and \$5.5 million in 2007. Our actual expenditures may differ from these estimates. Capital expenditures incurred to develop proved undeveloped reserves were \$21.8 million in 2004, \$28.4 million in 2003 and \$28.5 million in 2002.

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		
	2004	2003	2002
	(In thousands)		
Standardized measure of discounted cash flows at beginning of year	\$ 486,296	\$ 351,042	\$ 199,983
Sales and transfers of oil and gas produced, net of production costs	(208,492)	(161,670)	(84,231)
Net changes in prices and production costs	76,957	134,883	198,760
Net changes in estimated development costs	(40,570)	(13,169)	(4,229)
Net changes in income tax expense	(63,665)	(47,324)	(79,090)

Extensions, discoveries and improved recovery less related costs	321,813	141,970	123,755
Proved oil and gas reserves purchased		13,998	
Proved oil and gas reserves sold			(6,997)
Previously estimated development costs incurred during the year	32,932	28,477	22,893
Revisions of previous quantity estimates	(6,579)	(34,006)	(24,244)
Other changes	(25,026)	36,991	(15,556)
Accretion of discount	65,183	35,104	19,998
Standardized measure of discounted future net cash flows end of year	\$ 638,849	\$ 486,296	\$ 351,042

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REMINGTON OIL AND GAS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 10 Quarterly Financial Information (Unaudited)

	For Years Ending December 31,	
	2004	2003
	(In thousands, except per-share data)	
First Quarter		
Net revenues(1)	\$ 46,057	\$ 42,304
Net income	\$ 11,001	\$ 11,687
Basic net income per share	\$ 0.41	\$ 0.44
Diluted net income per share	\$ 0.39	\$ 0.42
Second Quarter		
Net revenues(1)	\$ 58,265	\$ 45,780
Net income	\$ 14,988	\$ 12,264
Basic net income per share	\$ 0.55	\$ 0.46
Diluted net income per share	\$ 0.53	\$ 0.44
Third Quarter		
Net revenues(1)	\$ 59,904	\$ 46,867
Net income	\$ 15,639	\$ 10,068
Basic net income per share	\$ 0.57	\$ 0.38
Diluted net income per share	\$ 0.55	\$ 0.36
Fourth Quarter		
Net revenues(1)	\$ 69,279	\$ 47,627
Net income	\$ 19,368	\$ 8,904
Basic net income per share	\$ 0.70	\$ 0.33
Diluted net income per share	\$ 0.67	\$ 0.32

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

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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.

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, 2004, 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, 2004, 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, 2004. 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, 2004, is included in this Item under the heading Report of Independent Registered Public Accounting Firm on Internal Control over Financial Reporting.

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 (the Company), a Delaware corporation, maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the

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effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, 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, 2004, 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, 2004 and 2003 and the related consolidated statements of income, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2004 of the Company and our report dated March 14, 2005 expressed an unqualified opinion thereon.

Ernst & Young LLP

Dallas, Texas
March 14, 2005

Item 9B. Other Information.

On May 24, 2004, our stockholders approved the Remington Oil and Gas Corporation 2004 Stock Incentive Plan. By resolution at its October 14, 2004, meeting, the Compensation Committee of the Board of Directors, a committee composed entirely of independent directors, approved restricted stock grant transactions totaling 200,000 shares to be issued in accordance with the 2004 Stock Incentive Plan. The Board of Directors by Unanimous Consent in lieu of Meeting, dated October 14, 2004, ratified the action of the Compensation Committee. All of our directors, officers, and other employees, except one, received grants. In accordance with the 2004 Stock Incentive Plan the grants are subject to written agreements between the

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Company and each grantee. These stock grant agreements have not yet been finalized and have not been executed by either the respective grantee or the Company.

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 our definitive proxy statement for the annual meeting of stockholders to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 no later than 120 days after the end of the fiscal year covered by this Form 10-K, and such portion of the proxy statement is hereby incorporated by reference.

Item 11. *Executive Compensation.*

The information required by Item 11, Executive Compensation, will be included in our definitive proxy statement for the annual meeting of stockholders to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 no later than 120 days after the end of the fiscal year covered by this Form 10-K, and such portion of the proxy statement is hereby incorporated by reference.

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 our definitive proxy statement for the annual meeting of stockholders to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 no later than 120 days after the end of the fiscal year covered by this Form 10-K, and such portion of the proxy statement is hereby incorporated by reference.

Item 13. *Certain Relationships and Related Transactions.*

The information required by Item 13, Certain Relationships and Related Transactions, will be included in our definitive proxy statement for the annual meeting of stockholders to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 no later than 120 days after the end of the fiscal year covered by this Form 10-K, and such portion of the proxy statement is hereby incorporated by reference.

Item 14. *Principal Accountant Fees and Services.*

The information required by Item 14, Principal Accountant Fees and Services, will be included in our definitive proxy statement for the annual meeting of stockholders to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 no later than 120 days after the end of the fiscal year covered by this Form 10-K, and such portion of the proxy statement is hereby incorporated by reference.

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PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a) Documents filed as part of this report:

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

(i) Independent Registered Public Accounting Firm's Report

(ii) Consolidated Balance Sheets as of December 31, 2004 and 2003

(iii) Consolidated Statements of Income for the years ended December 31, 2004, 2003 and 2002

(iv) Consolidated Statement of Stockholders' Equity for the years ended December 31, 2004, 2003 and 2002

(v) Consolidated Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002

(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

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 Corporation 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*	Box Energy Corporation Severance Plan.
10.7##	Box Energy Corporation 1997 Stock Option Plan (as amended June 17, 1999 and May 23, 2001).
10.8*	Box Energy Corporation Non-Employee Director Stock Purchase Plan.

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10.9#	Form of Employment Agreement effective September 30, 1999, by and between Remington Oil and Gas Corporation and two executive officers.
10.10#	Form of Employment Agreement effective September 30, 1999, by and between Remington Oil and Gas Corporation and an executive officer.
10.11+	Employment Agreement effective January 31, 2000, by and between Remington Oil and Gas Corporation and James A. Watt.
10.12***	Form of Employment Agreement effective April 30, 2002, by and between Remington Oil and Gas Corporation and an executive officer.
10.13****	Form of Amendment to the Employment Agreements by and between Remington Oil and Gas Corporation and each of James A. Watt and an executive officer.
10.14**	Form of Contingent Stock Grant Agreement Directors.
10.15**	Form of Contingent Stock Grant Agreement Employees.

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Exhibit

10.16**	Form of Amendment to Contingent Stock Grant Agreement Directors.
10.17**	Form of Amendment to Contingent Stock Grant Agreement Employees.
10.18####	Remington Oil and Gas Corporation 2004 Stock Incentive Plan.
14.1###	Code of Business Conduct and Ethics.
21####	Subsidiaries of the 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.

* 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-Q (file number 1-11516) for the fiscal quarter ended September 30, 1999 filed with the Commission on November 12, 1999.

+ Incorporated by reference to the Company's Form 10-K (file number 1-11516) for the fiscal year ended December 31, 1999 filed with the Commission on March 29, 2000.

** 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.

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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, 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 10-Q (file number 1-11516) for the fiscal quarter ended September 30, 2004 filed with the Commission on October 28, 2004.

Filed herewith.

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SIGNATURES

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

Remington Oil and Gas Corporation
By: /s/ James A. Watt

James A. Watt
Chairman and Chief Executive Officer

Date: March 16, 2005

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.

John E. Goble, Jr.
Director

/s/ William E. Greenwood

William E. Greenwood
Director

/s/ Robert P. Murphy

Robert P. Murphy
Director

/s/ David E. Preng

David E. Preng
Director

/s/ Thomas W. Rollins

Thomas W. Rollins
Director

/s/ Alan C. Shapiro

Alan C. Shapiro
Director

/s/ James A. Watt

James A. Watt
Director

Officers:

/s/ James A. Watt

James A. Watt
Chairman and Chief
Executive Officer

/s/ Frank T. Smith, Jr.

Frank T. Smith, Jr.
Senior Vice President/ Finance
(Principal Financial Officer)

/s/ Edward V. Howard

Edward V. Howard
Vice President/ Controller
(Principal Accounting Officer)

Date: March 16, 2005

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- #### Filed herewith.