UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark one)

☑ **Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year-ended December 31, 2004
or

o **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from__________ to __________

Commission file number 0-9592

RANGE RESOURCES CORPORATION

(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**34-1312571** (IRS Employer Identification No.)
777 Main Street, Suite 800, Fort Worth, Texas (Address of Principal Executive Offices)	**76102** (Zip Code)

Registrant's Telephone Number, Including Area Code
(817) 870-2601

Securities to be requested pursuant to Section 12(b) of the Act:

Title Of Each Class	Name Of Each Exchange On Which Registered
Common Stock, $.01 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ Noo

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2).

Yes ☑ Noo

The aggregate market value of the voting and non-voting common equity held by non-affiliates (excluding voting shares held by officers and directors) as of June 30, 2004 was $988,759,000.

As of February 26, 2005, there were 81,435,533 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the registrant's Proxy Statement to be furnished to stockholders in connection with its 2005 Annual Meeting of Stockholders are incorporated by reference in Part III of this Form 10-K.

RANGE RESOURCES CORPORATION

Annual Report on Form 10-K
Year Ended December 31, 2004

Unless the context otherwise indicates, all references in this report to "Range," "we" "us" or "our" are to Range Resources Corporation and its subsidiaries. Unless otherwise noted, all information in the report relating to oil and gas reserves and the estimated future net cash flows attributable to those reserves are based on estimates and are net to our interest. If you are not familiar with the oil and gas terms used in this report, please refer to the explanation of such terms under the caption "Glossary" at the end of Item 7 of this report.

TABLE OF CONTENTS

PART I

ITEM 1. BUSINESS

General

We are engaged in the exploration, development and acquisition of oil and gas properties, primarily in the Southwestern, Appalachian and Gulf Coast regions of the United States. We seek to increase reserves and production through internally generated drilling projects coupled with complementary acquisitions. Previously, we held our Appalachian assets through a 50% owned joint venture, Great Lakes Energy Partners L.L.C. or Great Lakes. On June 23, 2004, we purchased the 50% of Great Lakes that we did not own. In December 2004, we also purchased additional Appalachian properties through the purchase of PMOG Holdings, Inc, a private company, or Pine Mountain.

At year-end 2004, our proved reserves had the following characteristics:

- 1.18 Tcfe of proved reserves
- 81% natural gas;
- 64% proved developed;
- 77% operated; a reserve life of 14.9 years (based on fourth quarter 2004 production); and
- a pre-tax present value of $2.4 billion.

At year-end 2004, we owned 2,428,000 gross (1,890,000 net) acres of leasehold plus over 400,000 royalty acres. We have built a multi-year inventory of drilling projects which includes over 5,000 identified drilling locations.

History

Range was incorporated in early 1980 under the name Lomak Petroleum, Inc. and later that year, we completed an initial public offering and began trading on the NASDAQ. In 1996, our common stock was listed on the New York Stock Exchange. In 1998, we changed our name to Range Resources Corporation. In 1999, we implemented a strategy of internally generated drillbit growth coupled with complementary acquisitions. Our objective is to build stockholder value through consistent growth in reserves and production on a cost efficient basis. During the past three years, we have increased our proved reserves 129%, while production has increased 31% during that same time period.

Business Strategy

Our strategy is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. In implementing our strategy, we employ the following principal elements:

- *Concentrate in Core Operating Areas.* We currently operate in three regions; the Southwest (which includes the Permian Basin of West Texas, the East Texas Basin, the Texas Panhandle and Anadarko Basin of Western Oklahoma), Appalachia and Gulf Coast. Concentrating our drilling efforts in core areas allows us to develop the regional expertise needed to interpret specific geological trends and develop economies of scale. Operating in these different core areas allows us to blend the production characteristics of each area to balance our portfolio. We believe our geographic focus supports our overall goal to maintain a long-lived reserve base and achieve consistently favorable financial results.

- *Maintain Multi-Year Drilling Inventory.* We use our technical expertise to build and maintain a multi-year drilling inventory. This drilling inventory serves as the catalyst to grow our reserves and production consistently from year to year. Currently, we have over 5,000 identified drilling locations in inventory. In 2004, we drilled 476 gross (397 net) wells. In 2005, our capital program targets the drilling of 787 gross (586 net) wells.

- *Make Complementary Acquisitions.* We target complementary acquisitions in existing core areas. One of our initiatives includes identifying acquisition candidates where our existing scientific knowledge is transferable and drilling results are repeatable. Over the past three years, we have completed $670.0 million of complementary acquisitions. These acquisitions have been located in the Southwest and Appalachia regions.

- *Manage Our Risk Exposure.* Because certain of our exploration projects may involve high dry hole costs, we often bring in industry partners in order to reduce financial exposure. We generally plan to limit our exploratory expenditures to no more than 20% of the total capital budget per year. We also invest in new seismic data and technology each year. By equipping our geologists and geophysicists with state-of-the-art seismic technology, we hope to multiply the number of higher potential prospects we drill without substantially adding to dry hole risk.

- *Maintain Flexibility.* Given the volatility of commodity prices and the risks involved in drilling, we remain flexible and may adjust our capital budget throughout the year. We may defer capital projects in order to seize an attractive acquisition opportunity. If certain areas generate higher than anticipated returns, we may accelerate drilling in those areas and decrease capital expenditures elsewhere. We also believe in maintaining a strong balance sheet and using commodity hedging. This allows us to take advantage of opportunities in cyclical price environments as well as providing more consistent financial results.

Significant accomplishments in 2004

- *72% reserve growth and 24% production growth* - The most visible confirmation of the successful execution of our business strategy lies in these statistics. Growth in reserves and production on a cost-efficient basis in 2004 was accomplished through a combination of drilling success and complementary acquisitions. Annual growth of this magnitude is likely not repeatable on a consistent year-to-year basis; however, our 2004 reserve growth and cost performance signal successful execution of our business strategy.

- *Positive financial results* – This year produced five-year highs in revenue, pre-tax income, stockholders’ equity and net cash provided by operating activities. Debt leverage, as measured by our book debt to total capital ratio, declined from year-end 2003 to year-end 2004 even though we experienced significant growth in our oil and gas reserves and capital spending. These results speak to the elements of our strategy regarding maintaining flexibility and managing our risk exposure.

- *Favorable drilling results* — We drilled 476 gross (397 net) wells in 2004, a significant increase from the 358 gross (200.3 net) wells drilled in 2003. Given that a large multi-year drilling inventory is an element of our business strategy, it is important that we demonstrate that we have the capability to successfully drill a large number of wells each year that successfully produce oil and gas. Despite higher drilling costs and a competitive market for drilling equipment and services, our drilling results were very successful as our extensions and discoveries added 155.9 Bcfe to our reserves in 2004.

- *Complementary acquisitions completed* – Growth through successful complementary acquisitions is a core element of our business strategy. Two material acquisitions, the Great Lakes transaction and the Pine Mountain acquisition, significantly expanded our operations in the Appalachian Basin. Like the 2003 Conger field acquisition in the Permian Basin, these transactions demonstrate the application by experienced technical staff professionals of their local knowledge and expertise to core area opportunities where Range has lengthy operating experience and significant economies of scale.

- *Balance sheet simplified* – We have endeavored over the past several years to simplify the balance sheet making it easier for investors to understand. We have lowered our financing costs through retiring older higher cost debt, expanding our senior credit facility and making greater use of senior subordinated notes. In 2004, we retired our 6% convertible notes. In addition, we converted to common stock our 5.9% convertible preferred stock. Our capital structure now consists of bank debt, senior subordinated notes and common equity.

- *Drilling inventory expanded, coalbed methane and shale plays added* – In 2004, our portfolio of drilling opportunities was expanded to over 5,000 identified drilling locations. We also added geologic diversity through expansion of our coalbed methane projects and the initiation of two shale gas plays. The Pine Mountain acquisition in particular exponentially increases our existing and future drilling opportunities in coalbed methane. While still in the early stages of technological evaluation, shale gas, like coalbed methane, adds depth to our long-term prospects and drilling inventory.

Plans for 2005

We have announced a $254.0 million capital budget for 2005, excluding acquisitions. The budget includes $212.2 million to drill 787 gross (586 net) wells and to undertake 75 gross (53 net) recompletions. Approximately 46% of the budget is attributable to the Appalachian region, with 43% allocated to the Southwestern region and 11% to the Gulf Coast. Also included is $29.6 million for land and seismic and $12.1 million for the expansion and enhancement of gathering systems and facilities.

Acquisitions

On December 10, 2004, we acquired additional Appalachia oil and gas properties with the purchase of Pine Mountain. The cash purchase price was $222.1 million. Approximately one half of the transaction is attributable to royalty interests. We estimate that the proved reserves assigned to the properties purchased were 205 Bcfe, 99% natural gas and only 40% developed with more than 80% of the reserves coalbed methane. The properties acquired include 417,000 acres located primarily in Virginia and West Virginia. On 373,000 mineral acres, the interest includes a royalty and a working interest. Of the 1,872 producing wells acquired, we own a royalty interest in 1,317 wells, a royalty and working interest in 516 wells and a working interest in 39 wells.

In June 2004, we purchased the 50% of Great Lakes Energy Partners L.L.C., or Great Lakes, that we did not previously own. The cash purchase price was $228.9 million. As a result of the Great Lakes acquisition, we increased our estimated proved reserves by 255 Bcfe. These reserves are 87% natural gas, 92% operated and have a 20-year reserve life index.

Marketing and Customers

We market nearly all of our oil and gas production from the properties we operate for both our account and the account of the other working interest owners in these properties. Gas sales are made pursuant to various contractual arrangements, including month-to-month and one to five-year contracts. Pricing on month-to-month and short term contracts is largely New York Mercantile Exchange, or NYMEX, related. For one to five-year contracts, gas is sold based on NYMEX pricing, published regional index pricing or percentage of proceeds sales based on indexes. Less than 600 mcf per day is sold under long term fixed prices. Most contracts contain provisions for price adjustment, termination and other terms customary in the industry. Gas is sold to utilities, marketing companies and industrial users. Oil is sold under contracts ranging in terms from month-to-month or up to as long as one year. The price for oil is generally equal to a posted price set by major purchasers in the area. Oil and gas purchasers are selected on the basis of price, credit quality and service. For a list of purchasers of our oil and gas production that accounted for 10% or more of consolidated revenue, see the information set forth in the notes to our consolidated financial statements under the caption “Major Customers” in Note 15. Because alternative purchasers of oil and gas are readily available, we believe that the loss of any of these purchasers would not have a material adverse effect on us.

We enter into hedging transactions with unaffiliated third parties for portions of our production to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in oil and gas prices. For a more detailed discussion, please see the information set forth in Item 7 of this report “Management’s Discussion and Analysis of Financial Condition and Results of Operations”. Proximity to local markets, availability of competitive fuels and overall supply and demand are factors affecting the prices for which production can be sold. Factors outside of our control, such as international political developments, overall energy supply and demand, weather conditions, economic growth rates and other factors in the United States and elsewhere have had, and will continue to have, a significant effect on energy prices.

We incur gathering and transportation expenses to move our natural gas from the wellhead to purchaser-specified delivery point. These expenses vary based on volume and distance shipped, and the fee charged by the third party transporters. In the Southwest and Gulf Coast regions, our natural gas and oil are transported primarily through third party gathering systems and pipelines. Transportation space on these gathering systems and pipelines is occasionally limited. In Appalachia, we own approximately 4,800 miles of gas gathering pipelines which transport a majority of our Appalachia gas production as well as third party gas to transmission lines and directly to end-users. See “Risk Factors – Our business depends on oil and natural gas transportation facilities, some of which are owned by others,” in this Item 1.

Production, Revenues and Price History

The following table sets forth information regarding oil and gas production, revenues and direct operating expenses for the last three years.

	Year Ended December 31,		
	2004	2003	2002
Production			
Gas (Mmcf)	50,722	43,510	41,096
Crude oil (Mbbl)	2,512	2,023	1,873
Natural gas liquids (Mbbl)	988	401	407
Total (Mmcfe) (a)	71,726	58,053	54,772
Revenues ($000)			
Gas	$ 225,738	$ 171,291	$ 144,030
Crude oil	70,439	47,599	41,665
Natural gas liquids	19,526	7,512	5,259
Transportation and gathering	2,202	3,509	3,495
Total	317,905	229,911	194,449
Direct operating expenses (b)	66,812	49,317	40,443
Gross margin	$ 251,093	$ 180,594	$ 154,006
Average sales price (excluding hedging)			
Gas (per mcf)	$ 5.79	$ 5.10	$ 3.02
Crude oil (per bbl)	39.25	28.42	23.34
Natural gas liquids (per bbl)	23.73	18.75	12.93
Total (per mcfe) (a)	5.80	4.94	3.16
Average sales price (including hedging)			
Gas (per mcf)	$ 4.45	$ 3.94	$ 3.50
Crude oil (per bbl)	28.04	23.53	22.25
Natural gas liquids (per bbl)	19.76	18.73	12.92
Total (per mcfe) (a)	4.40	3.90	3.49
Operating costs (per mcfe)			
Direct	$ 0.65	$ 0.63	$ 0.58
Production and ad valorem taxes	0.29	0.22	0.16
Total	$ 0.94	$ 0.85	$ 0.74

(a) Oil and NGLs are converted to mcfe at a rate of one barrel equals 6 mcf.

(b) Includes severance, production and ad valorem taxes.

Competition

We encounter substantial competition in acquiring oil and gas properties, securing and retaining personnel, conducting drilling and field operations, and marketing production. Competitors in exploration, development, acquisitions and production include the major oil companies as well as numerous independent oil companies, individual proprietors and others. Although our sizable acreage position and core area concentration provide some competitive advantages, many competitors have financial and other resources substantially exceeding ours. Therefore, competitors may be able to pay more for desirable leases and to evaluate, bid for and purchase a greater number of properties or prospects than the financial or personnel resources of Range allow. Our ability to replace and expand our reserve base depends on our ability to attract and retain quality personnel, and identify and acquire suitable producing properties and prospects for future drilling.

Governmental Regulation

Our operations are substantially affected by federal, state and local laws and regulations. In particular, oil and gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. Failure to comply with such laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future cost or impact of compliance.

Environmental Matters

Our operations are subject to stringent federal, state and local laws governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental departments such as the Environmental Protection Agency (or the "EPA") issue regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, frontier and other protected areas, require some form of remedial action to prevent pollution from former operations such as plugging abandoned wells, and impose substantial liabilities for pollution resulting from operations. In addition, these laws, rules and regulations may restrict the rate of production. The regulatory burden on the oil and gas industry increases the cost of doing business, affecting growth and profitability. Changes in environmental laws and regulations occur frequently, and changes that result in more stringent and costly waste handling, disposal or clean-up requirements could adversely affect our operations and financial position, as well as the industry in general. We believe we are in substantial compliance with current applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital expenditures in connection with environmental remediation matters in 2004, nor do we anticipate that such expenditures will be material in 2005.

The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include owners or operators of the disposal site or sites where the release occurred and companies that disposed of or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. Furthermore, although petroleum, including crude oil and natural gas, is exempt from CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as "hazardous substances" under CERCLA and that such wastes may become subject to liability and regulation under CERCLA. State initiatives to further regulate the disposal of oil and gas wastes are pending in certain states and these initiatives could have a significant impact on us. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environmental statutes, common law or both.

The Federal Water Pollution Control Act, or FWPCA, imposes restrictions and strict controls regarding the discharge of produced waters and other oil and gas wastes into waters of the United States. Permits must be obtained to discharge pollutants into state and federal waters. The FWPCA and analogous state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of oil and other hazardous substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. State water discharge regulations and the federal National Pollutant Discharge Elimination System general permits applicable to the oil and gas industry generally prohibit the discharge of produced water, sand and some other substances into coastal waters. The cost to comply with zero discharges mandated under federal and state law has not had a material adverse impact on our financial condition and results of operations. Some oil and gas exploration and production facilities are required to obtain permits for their storm water discharges. Costs may be incurred in connection with treatment of wastewater or developing storm water pollution prevention plans.

The Resource Conservation and Recovery Act, or RCRA, as amended, generally does not regulate most wastes generated by the exploration and production of oil and gas. RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy." However, these wastes may be regulated by the EPA or state agencies as solid waste. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, can be regulated as hazardous wastes. Although the costs of managing solid hazardous waste may be significant, we do not expect to experience more burdensome costs than similarly situated companies.

The U.S. Oil Pollution Act, or OPA, requires owners and operators of facilities that could be the source of an oil spill into “waters of the United States” (a term defined to include rivers, creeks, wetlands and coastal waters) to adopt and implement plans and procedures to prevent any spill of oil into any waters of the United States. OPA also requires affected facility owners and operators to demonstrate that they have at least $35 million in financial resources to pay for the costs of cleaning up an oil spill and compensating any parties damaged by an oil spill. Substantial civil and criminal fines and penalties can be imposed for violations of OPA and other environmental statues.

Stricter standards in environmental legislation may be imposed on the oil and gas industry in the future. For instance, legislation has been proposed in Congress from time to time that would alter the RCRA exemption by reclassifying certain oil and gas exploration and production wastes as “hazardous wastes” and make the waste subject to more stringent handling, disposal and clean-up restrictions. If such legislation were enacted, it could have a significant impact on our operating costs, as well as the industry in general. Compliance with environmental requirements generally could have a material adverse effect on our capital expenditures, earnings or competitive position. Although we have not experienced any material adverse effect from compliance with environmental requirements, no assurance may be given that this will continue.

Risk Factors and Cautionary Statement for Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995

Certain information included in this report, other materials filed or to be filed with the Securities and Exchange Commission (or the “SEC”), as well as information included in oral statements or other written statements made or to be made by us contain or incorporate by reference certain statements (other than statements of historical fact) that constitute forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. When used herein, the words “budget,” “budgeted,” “assumes,” “should,” “goal,” “anticipates,” “expects,” “believes,” “seeks,” “plans,” “estimates,” “intends,” “projects” or “targets” and similar expressions that convey the uncertainty of future events or outcomes are intended to identify forward-looking statements. Where any forward-looking statement includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that while we believe these assumptions or bases to be reasonable and to be made in good faith, assumed facts or bases almost always vary from actual results and the difference between assumed facts or bases and the actual results could be material, depending on the circumstances. It is important to note that our actual results could differ materially from those projected by such forward-looking statements. Although we believe that the expectations reflected in such forward-looking statements are reasonable and such forward-looking statements are based upon the best data available at the date this report is filed with the SEC, we cannot assure you that such expectations will prove correct. Factors that could cause our results to differ materially from the results discussed in such forward-looking statements include, but are not limited to, the following: production variance from expectations, volatility of oil and gas prices, hedging results, the need to develop and replace reserves, the substantial capital expenditures required to fund operations, exploration risks, environmental risks, uncertainties about estimates of reserves, competition, litigation, government regulation, political risks, our ability to implement our business strategy, costs and results of drilling new projects, mechanical and other inherent risks associated with oil and gas production, weather, availability of drilling equipment and changes in interest rates. All such forward-looking statements in this document are expressly qualified in their entirety by the cautionary statements in this paragraph, and we undertake no obligation to publicly update or revise any forward-looking statements.

With the previous paragraph in mind, you should consider the following important factors that could cause actual results to differ materially from those expressed in any forward-looking statement made by us or on our behalf:

Risk Factors

Volatility of oil and natural gas prices significantly affects our cash flow and capital resources and could hamper our ability to produce oil and gas economically

Oil and natural gas prices are volatile, and an extended decline in prices would adversely affect our profitability and financial condition.The oil and natural gas industry is typically cyclical, and prices for oil and natural gas can be highly volatile. Historically, the industry has experienced severe downturns characterized by oversupply and/or weak demand. For example, in 1998 and early 1999, oil and natural gas prices declined, which contributed to the substantial losses we reported in those years. By early 2001, oil and natural gas prices reached levels above historical norms. Prices declined in the second half of 2001 but have risen steadily since mid-2002. Recent oil and natural gas prices are at historic highs, with oil prices recently reaching $56 per barrel and natural gas prices reaching $10 per mcf in some markets. These record oil and natural gas prices have contributed to our positive earnings over the last 18-24 months. However, long-term supply and demand for oil and natural gas is uncertain and subject to a myriad of factors including technology, geopolitics, weather patterns and economics.

Many factors affect oil and natural gas prices including general economic conditions, consumer preferences, discretionary spending levels, interest rates and the availability of capital to the industry. Decreases in oil and natural gas prices from current levels could adversely affect our revenues, net income, cash flow and proved reserves. Significant and prolonged price decreases could have a material adverse effect on our operations and limit our ability to fund capital expenditures. Without the ability to fund capital expenditures, we may be unable to replace production.

Hedging transactions may limit our potential gains and involve other risks

To manage our exposure to price risk, we enter into hedging arrangements from time to time with respect to a portion of our future production. The goal of these hedges is to lock in prices so as to limit volatility and increase the predictability of cash flow. These transactions limit our potential gains if oil and natural gas prices rise above the price established by the hedge. For example, at December 31, 2004, we were party to hedging arrangements covering 19.7 Bcf and 0.6 million barrels of oil and 0.2 million barrels of NGLs. We also had collars covering 37.8 Bcf of gas and 2.8 million barrels of oil. The hedges' fair value was a pre-tax loss of $71.9 million. If oil and natural gas prices continue to rise, we could be subject to margin calls.

In addition, hedging transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- the counterparties to our futures contracts fail to perform under the contracts; or
- a sudden, unexpected event materially impacts oil or natural gas prices or the relationship between the hedged price index and the oil and gas sales price.

Information concerning our reserves and future net reserve estimates is uncertain

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, including many factors beyond our control. Estimates of proved undeveloped reserves, which comprise a significant portion of our reserves, are by their nature uncertain. Although we believe these estimates are reasonable, actual production, revenues and costs to develop expenditures will likely vary from estimates, and these variances could be material.

The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, judgment, assumptions used regarding quantities of oil and natural gas in place, recovery rates and future prices for oil and natural gas. Actual prices, production, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from those assumed in our estimates, and such variances may be material. Any variance in the assumptions could materially affect the estimated quantity and value of the reserves.

If oil and natural gas prices decrease or exploration efforts are unsuccessful, we may be required to take write-downs of our oil and natural gas properties.

In the past, we have been required to write down the carrying value of our oil and natural gas properties, and there is a risk that we will be required to take additional write-downs in the future. This could occur when oil and natural gas prices are low or if we have downward adjustments to our estimated proved reserves, increases in our estimates of operating or development costs or deterioration in our exploration results.

Accounting rules require that the carrying value of oil and natural gas properties be periodically reviewed for possible impairment. "Impairment" is recognized when the book value of a proven property is greater than the expected undiscounted future cash flows from that property and on acreage when conditions indicate the carrying value is not recoverable. We may be required to write down the carrying value of a property based on oil and natural gas prices at the time of the impairment review, as well as a continuing evaluation of development results, production data, economics and other factors. While an impairment charge which reflects our long term ability to recover on a prior investment does not impact cash or cash flow from operating activities, it reduces our earnings and increases our leverage ratios.

For example, based primarily on the poor performance of certain properties acquired in 1997 and 1998 and significantly lower oil and natural gas prices, we recorded impairments of $215.0 million in 1998 and $29.9 million in 1999. At year-end 2001, we recorded an impairment of $31.1 million due to year-end prices. At year-end 2004, we recorded an impairment of $3.6 million on an offshore property due to hurricane damage and related production declines.

Our business is subject to operating hazards and environmental regulations that could result in substantial losses or liabilities

Oil and natural gas operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, formations with abnormal pressures, pipelines ruptures or spills, pollution, releases of toxic natural gas and other environmental hazards and risks. If any of these hazards occur, we could sustain substantial losses as a result of:

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

Our current and former operations are subject to numerous and increasingly strict federal, state and local laws, regulations and enforcement policies relating to the environment. We may incur significant costs and liabilities in complying with existing or future environmental laws, regulations and enforcement policies and may incur costs arising out of property damage or injuries to employees and other persons. These costs may result from our current and former operations and even may be caused by previous owners of property we own or lease. Any past, present or future failure by us to completely comply with environmental laws, regulations and enforcement policies could cause us to incur substantial fines, sanctions or liabilities from cleanup costs or other damages. Incurrence of those costs or damages could reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

We maintain insurance against some, but not all, of these potential risks and losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs that is not fully covered by insurance, it could have a material adverse affect on our financial condition and results of operations.

We are subject to financing and interest rate exposure risks

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities and place us at a competitive disadvantage. For example, approximately 40% of our debt is at fixed interest rates with the remaining 60% subject to variable interest rates.

Some of our current and potential competitors have greater resources than we have and we may not be able to successfully compete in acquiring, exploring and developing new properties

We face competition in every aspect of our business, including, but not limited to, acquiring reserves and leases, obtaining goods, services and employees needed to operate and manage our business and marketing oil and natural gas. Competitors include multinational oil companies, independent production companies and individual producers and operators. Many of our competitors have greater financial and other resources than we do.

The oil and natural gas industry is subject to extensive regulation

The oil and natural gas industry is subject to various types of regulations in the United States by local, state and federal agencies. Legislation affecting the industry is under constant review for amendment or expansion, frequently increasing our regulatory burden. Numerous departments and agencies, both state and federal, are authorized by statute to issue rules and regulations binding on participants in the oil and natural gas industry. Compliance with such rules and regulations often increases our cost of doing business and, in turn, decreases our profitability.

Acquisitions are subject to the risks and uncertainties of evaluating reserves and potential liabilities and may be disruptive and difficult to integrate into our business

We could be subject to significant liabilities related to our acquisitions. It generally is not feasible to review in detail every individual property included in an acquisition. Ordinarily, a review is focused on higher valued properties. However, even a detailed review of all properties and records may not reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not always inspect every well we acquire, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is performed.

For example, in 1997, we consummated a large acquisition which proved extremely disappointing. Production from the acquired properties fell more rapidly than anticipated and further development results were below the results we had originally projected. The poor production performance of these properties resulted in material downward reserve revisions. We cannot assure you that our recent and/or future acquisition activity will not result in similar disappointing results.

In addition, there is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our strategy of completing acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to pursue our acquisition strategy may be hindered if we are not able to obtain financing on terms acceptable to us or regulatory approvals.

Acquisitions often pose integration risks and difficulties. In connection with recent and future acquisitions, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations. Possible future acquisitions could result in our incurring additional debt, contingent liabilities, expenses, and diversion of resources, all of which could have a material adverse effect on our financial condition and operating results.

Our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel

Our success is highly dependent on our senior management personnel, none of which are currently subject to an employment contract. The loss of one or more of these individuals could have a material adverse effect on our business. Furthermore, competition for experienced technical and other professional personnel is intense. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected.

Our future success depends on our ability to replace reserves that we produce

Because the rate of production from oil and natural gas properties generally declines as reserves are depleted, our future success depends upon our ability to economically find or acquire and produce additional oil and natural gas reserves. Except to the extent that we acquire additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline materially as reserves are produced. Future oil and natural gas production, therefore, is highly dependent upon our level of success in acquiring or finding additional reserves that are economically recoverable. We cannot assure you that we will be able to find or acquire and develop additional reserves at an acceptable cost.

A portion of our business is subject to special risks related to offshore operations generally and in the Gulf of Mexico specifically

Offshore operations are subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions, or result in loss of equipment and properties.

Production of reserves from reservoirs in the Gulf of Mexico generally declines more rapidly than from reservoirs in many other producing regions of the world. This results in recovery of a relatively higher percentage of reserves from properties in the Gulf of Mexico during the initial few years of production. As a result, reserve replacement needs from new prospects are greater and require us to incur significant capital expenditure to replace production.

New technologies may cause our current exploration and drilling methods to become obsolete

The oil and natural gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are not able to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.

Our business depends on oil and natural gas transportation facilities, some of which are owned by others

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of pipeline systems owned by third parties. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships could materially affect our operations. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

Our significant indebtedness could limit our ability to successfully operate our business

We are leveraged and our exploration and development program will require substantial capital resources, estimated to range from $250 to $300 million per year over the next three years. The operation of our existing operations will also require ongoing capital expenditures. In addition, if we decide to pursue additional acquisitions, our capital expenditures will increase both to complete such acquisitions and to explore and develop any newly acquired properties.

The degree to which we are leveraged could have other important consequences, including the following:

- we may be required to dedicate a substantial portion of our cash flows from operations to the payment of our indebtedness, reducing the funds available for our operations;
- a portion of our borrowings are at variable rates of interest, making us vulnerable to increases in interest rates:
- we may be more highly leveraged than some of our competitors, which could place us at a competitive disadvantage;
- our degree of leverage may make us more vulnerable to a downturn in our business or the economy generally;
- the terms of our existing credit arrangements contain numerous financial and other restrictive covenants;
- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- we may have difficulties borrowing money in the future.

Despite our current levels of indebtedness we still may be able to incur substantially more debt. This could further increase the risks described above.

Any failure to meet our debt obligations could harm our business, financial condition and results of operation

If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to sell assets, seek additional equity or restructure our debt. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt in the future and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations and impair our liquidity.

Common stockholders will be diluted if additional shares are issued

Since 1998, we have exchanged 21.3 million shares of common stock for $146.7 million of debt and convertible securities. The exchanges were made based on the relative market value of the common stock and the debt and convertible securities at the time of the exchange. During 2001, $17.4 million of debt and convertible securities was exchanged for common stock. During 2002, $10.4

million of debt and convertible securities were exchanged for common stock. During 2003, $880,000 of debt was exchanged for common stock. In 2004, we exchanged our 5.9% convertible preferred stock for 5.9 million shares of common stock. Also in two transactions during 2004, we sold 17.9 million shares of common stock for total proceeds of $246.1 million which were used, in part, to finance our two large acquisitions during the year. While the exchanges have reduced interest expense, dividends and future repayment obligations, the larger number of common shares outstanding had a dilutive effect on our existing stockholders. Our ability to repurchase securities for cash is limited by our senior credit facility and the 7-3/8% senior subordinated notes agreement. We continue to review alternatives to further strengthen our balance sheet by reducing debt. In addition, we may issue additional shares of common stock, additional subordinated notes or other securities or debt convertible into common stock, to extend maturities or fund capital expenditures, including acquisitions. If we issue additional shares of our common stock in the future, it may have a dilutive effect on our outstanding shares.

Dividend limitations

Limits on the payment of dividends and other restricted payments, as defined, are imposed under our senior credit facility and under our 7-3/8% senior subordinated notes. These limitations may, in certain circumstances, limit or prevent the payment dividends independent of our dividend policy.

Our financial statements are complex

Due to accounting rules, our financial statements continue to be complex, particularly with reference to hedging, asset retirement obligations, stock options and the accounting for our deferred compensation plan. We expect such complexity to continue and possibly increase.

The price of our common stock may fluctuate significantly, which may result in losses for investors.

The market price of our common stock has been volatile. From January 1, 2003 to December 31, 2004, the last daily sale price of our common stock reported by the New York Stock Exchange ranged from a low of $5.05 per share to a high of $21.51 per share. We expect our stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These include:

- changes in oil and natural gas prices;
- variations in quarterly drilling, recompletions, acquisitions and operating results;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- additions or departures of key personnel;
- future sales of our stock.

We may fail to meet expectations of our stockholders or of securities analysts at some time in the future, and our stock price could decline as a result.

Available Information

We maintain an internet website under the name “www.rangeresources.com.” We make available, free of charge, on our website, the annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after providing such reports to the SEC. Also, our Corporate Governance principles, the charters of the Audit Committee, the Compensation Committee, the Dividend Committee, the Executive Committee, and the Governance and Nomination Committee, and the Code of Business Conduct and Ethics are also available on the website and in print to any stockholder who provides a written request to the Corporate Secretary at 777 Main Street, Suite 800, Fort Worth, Texas 76102.

We file annual, quarterly and current reports on Form 8-K, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934. The public may read and copy any materials that we file with the SEC at the SEC’s Public Reference Room at 450 Fifth Street, N.W., Washington DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including Range, that file electronically with the SEC. The public can obtain any document we file with the SEC at “www.sec.gov.”

Employees

As of January 1, 2005, we had 504 full-time employees, 303 of whom were field personnel. None are covered by a collective bargaining agreement. Management believes its relationship with employees is good. We regularly utilize independent consultants and contractors to perform various professional services, particularly in the areas of field production services such as pumping, maintenance, inspection and testing, permitting and environmental assessment.

ITEM 2. PROPERTIES

The table below summarizes certain data for our core operating areas for the year ended December 31, 2004:

Area	Average Daily Production (mcfe per day)	Total Production (mcfe)	Total Proved Reserves (mmcfe)	Percentage of Total Proved Reserves	Total Wells Drilled	
					Total (Gross)	Successful (Gross)
Southwest	101,583	37,179,252	358,183	30%	155	140
Appalachia	55,475	20,303,873	746,273	63%	306	302
Gulf Coast	38,915	14,242,752	70,969	7%	15	8
	195,973	71,725,877	1,175,425	100%	476	450

Southwestern division

The Southwestern division conducts drilling, production and field operations in the Permian Basin of West Texas and the East Texas Basin as well as in the Texas Panhandle and the Anadarko Basin of western Oklahoma. In the Southwestern division, we own interests in 1,600 net producing wells, 95% of which we operate. We have approximately 317,000 net acres under lease. Our average working interest is 73%.

In December 2003, we completed an $87.9 million producing property acquisition which added more than 500 operated wells and established ourselves as the largest operator in the Conger Field in Sterling County of West Texas. In addition, in April 2004, we purchased a private company owning oil and gas properties in the Permian Basin for $23.1 million with reserves of approximately 22 Bcfe. The related production is 75% oil and 52% of the reserves were proved developed. In total, production has increased in the Southwestern division over 40% from 2002.

Reserves increased 13.9 Bcfe at December 31, 2004, as compared to year end 2003, a 4% increase due to purchases and drilling additions. On an annual basis, production increased 30% over 2003. During 2004, the region spent $96.4 million to drill 147 (122.0 net) development wells, of which 137 (113.4 net) were productive and 8 (6.6 net) exploratory wells, of which 3 (2.1 net) were productive. During the year, the region achieved a 90% drilling success rate.

At December 31, 2004, the Southwestern division had a development inventory of 183 proven drilling locations and 200 proven recompletions. Development projects include recompletions, infill drilling and to a lesser extent, installation of secondary recovery projects. These activities also include increasing reserves and production through aggressive cost control, upgrading lifting equipment, improving gathering systems and surface facilities and performing restimulations and refracturing operations.

Appalachian division

Our property base in this division is located in the Appalachian Basin, and to a minor extent, the Michigan Basin of the northeastern United States. The reserves principally produce from the Pennsylvanian (coalbed formation), Upper Devonian, Medina, Clinton, Knox, Oriskany and Trenton Black River formations at depths ranging from 2,500 to 7,000 feet. After initial flush production, these properties are characterized by gradual decline rates, typically producing for 10 to 35 years. We own interests in approximately 8,400 net producing wells, 74% of which we operate and 4,800 miles of gas gathering lines. Our average working interest is 74%. We have approximately 1.8 million gross (1.5 million net) acres under lease.

In June 2004, we added to our Appalachian properties with the purchase of the 50% of Great Lakes that we did not own for $228.9 million which included estimated proved reserves of 255 Bcfe. In December 2004, we added properties with the Pine Mountain acquisition for $221.9 million. The properties include 417,000 acres located primarily in Virginia and West Virginia. This acquisition added estimated proved reserves of 205 Bcfe. Approximately half of the value is attributable to royalty interests. The reserves are 99% natural gas and are 40% developed. More than 80% of the Pine Mountain reserves are coalbed methane.

Reserves at December 31, 2004 increased 484.7 Bcfe, or 185% from 2003 due to the acquisitions mentioned above and from drilling additions. On an annual basis, production increased 56% from 2003. During 2004, the region spent $53.6 million to drill 297 (255.4 net) development wells, of which 294 (253.3 net) were productive and 9 (7.7 net) exploratory wells, of which 8 (6.7 net) were productive. During the year, the region achieved a 99% drilling success rate. At December 31, 2004, Great Lakes had an inventory of 2,682 proven drilling locations and 52 proven recompletions.

Gulf Coast division

Our Gulf Coast properties are located onshore in Texas, Louisiana and Mississippi and in the shallow waters of the Gulf of Mexico. The division's wells are characterized by high initial rates and relatively short reserve lives. Over the past several years, we have shifted our focus away from offshore to onshore Gulf of Mexico properties that provide greater operating control, generally lower costs and higher repeatability. Major onshore fields produce from Hartburg formations at depths of 10,000 to 11,000 feet in the Upper Texas Gulf Coast to the Upper Oligocene in South Louisiana at depths of 10,000 to 12,000 feet to the Sligo and Hosston formations at depths of 15,000 to 16,500 feet in the Oakvale field in Mississippi. We operate a majority of our onshore properties while third parties operate our offshore properties. Onshore, we have approximately 55,000 net acres under lease. Offshore properties include interests in 37 platforms in water depths ranging from 11 to 240 feet. Our offshore leasehold inventory includes 42,000 net acres. We own interests in 44 net producing wells, in this division, 44% of which we operate. Our average working interest is 30%. Our Gulf Coast division also owns a license of a 3-D seismic database covering over 800 contiguous blocks in the shallow water of the Gulf of Mexico, primarily offshore Louisiana.

Reserves declined 7.7 Bcfe, or 10%, from 2003 due to production partially offset by drilling additions from drilling. On an annual basis, production decreased 14% from 2003. During 2004, the region spent $34.0 million to drill 8 (3.0 net) development wells, of which 5 (1.8 net) were productive and 7 (1.9 net) exploratory wells, of which 3 (0.5 net) were productive. During the year, the division had a 53% drilling success rate. At December 31, 2004, the Gulf Coast division had an inventory of 8 proven drilling locations and 40 proven recompletions.

Proved Reserves

The following table sets forth estimated proved reserves at the end of each of the past five years:

	December 31,				
	2004	2003	2002	2001	2000
Natural gas (Mmcf)					
Developed	580,006	344,187	320,224	276,162	305,796
Undeveloped	366,422	142,216	120,043	112,765	121,871
Total	946,428	486,403	440,267	388,927	427,667
Oil and NGLs (Mbbls)					
Developed	27,715	24,912	17,176	14,066	17,215
Undeveloped	10,451	8,111	5,776	6,614	8,787
Total	38,166	33,023	22,952	20,680	26,002
Total (Mmcfe) (a)	1,175,425	684,541	577,977	513,005	583,679
% Developed	63.5%	72.1%	73.2%	70.3%	70.1%

(a) Oil and NGLs are converted to mcfe at a rate of one barrel equals 6 mcf.

Our percentage of proved developed reserves declined in 2004 due to the significant proved undeveloped reserves acquired in the Great Lakes and Pine Mountain acquisitions adding to our future drilling inventory. The Great Lakes acquisition moved our percentage of proved undeveloped reserves from 27% to 32% and the Pine Mountain acquisition increased that percentage to 37%. We do not disclose potential reserves classified as probable or possible associated with our acquisitions.

The following table sets forth summary information by division with respect to estimated proved reserves at December 31, 2004:

	Pre-tax Present Value (a)		Reserve Volumes			
	Amount (In thousands)	%	Oil & NGL (Mbbls)	Natural Gas (Mmcf)	Total (Mmcfe)	%
Appalachia	$ 1,369,271	57	10,244	684,809	746,273	63
Southwest	798,923	33	25,957	202,442	358,183	30
Gulf Coast	228,165	10	1,965	59,177	70,969	7
Total	$ 2,396,359	100	38,166	946,428	1,175,425	100

(a) Future cash inflows were discounted using a 10% annual discount rate and constant prices. Our pre-tax present value of $2.4 billion less discounted taxes of $877 million equals our standardized measure of $1.7 billion. See also footnote 18 to our consolidated financial statement.

At year-end 2004, the following independent petroleum consultants reviewed our reserves: DeGolyer and MacNaughton (Southwest and Gulf Coast), H.J. Gruy and Associates, Inc. (Southwest), and Wright and Company, Inc. (Appalachia). These engineers were selected for their geographic expertise and their history in engineering certain properties. At December 31, 2004, these consultants collectively reviewed approximately 88% of the proved reserves. All estimates of oil and gas reserves are subject to uncertainty. Historical variances between our reserve estimates and the aggregate estimates of our consultants have been less than 6%.

The following table sets forth the estimated future net revenues, excluding open hedging contracts, from proved reserves, the present value of those revenues and the expected benchmark prices used in projecting them over the past five years (in millions except prices):

	December 31,				
	2004	2003	2002	2001	2000
Future net revenue	$ 5,035	$ 2,687	$ 1,817	$ 750	$ 3,764
Present Value					
Pre-tax	2,396	1,396	965	399	1,964
After tax	1,749	1,003	500	311	1,506
Oil price (per barrel)	$ 40.44	$ 29.48	$ 27.52	$ 17.59	$ 24.46
Gas price (per mcf)	$ 6.05	$ 6.03	$ 4.76	$ 2.70	$ 9.57

Future net revenues represent projected revenues from the sale of proved reserves net of production and development costs (including production taxes and operating expenses). Such calculations, prepared in accordance with SFAS No. 69, "Disclosures about Oil and Gas Producing Activities," are based on costs and prices in effect at December 31 of each year. Weighted average product prices at December 31, 2004 were $40.44 per barrel of oil, $25.05 per barrel for natural gas liquids, and $6.05 per mcf of gas using benchmark spot prices of $43.33 per barrel and $6.18 per Mmbtu. There can be no assurance that the proved reserves will be produced within the periods indicated and prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties. No estimates of our reserves have been filed with or included in reports to another federal authority or agency since year-end.

Producing Wells

The following table sets forth information relating to productive wells at December 31, 2004. We also own royalty interests in an additional 1,690 wells. Wells are classified as oil or gas according to their predominant production stream.

	Total Wells		Average Working Interest
	Gross	Net	
Crude oil	2,062	1,737	84%
Natural gas	11,643	8,286	71%
Total	13,705	10,023	73%

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

Acreage

At December 31, 2004, we owned interests in developed and undeveloped oil and gas acreage as set forth in the table below. These ownership interests generally take the form of working interests in oil and gas leases or licenses that have varying terms. Developed acreage includes leased acreage that is allocated or assignable to producing wells or wells capable of production. Undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas or oil, regardless of whether or not the acreage contains proved reserves.

The following table sets forth certain information regarding our developed and undeveloped acreage held at December 31, 2004:

	Acres		Average Working Interest
	Gross	Net	
Developed	1,302,676	1,067,814	82%
Undeveloped	1,125,187	821,894	73%
Total [(a)]	2,427,863	1,889,708	78%

(a) Does not include 407,800 acres in which Appalachia owns royalty and overriding royalty interests ranging from 1.5% to 14.5%. Also, does not include 76,000 of acres in the Southwestern division related to a farm out.

Drilling Results

We engage in numerous drilling activities on properties presently owned by us and intend to drill or develop other properties we may acquire in the future. The following table summarizes drilling activity for the past three years. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells.

	2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	436.0	368.5	322.0	180.7	294.0	162.3
Dry	16.0	12.0	16.0	11.4	6.0	4.1
Exploratory wells						
Productive	14.0	9.2	11.0	3.8	17.0	6.9
Dry	10.0	6.9	9.0	4.4	11.0	5.3
Total wells						
Productive	450.0	377.7	333.0	184.5	311.0	169.2
Dry	26.0	18.9	25.0	15.8	17.0	9.4
Total	476.0	396.6	358.0	200.3	328.0	178.6
Success ratio	95%	95%	93%	92%	95%	95%

Real Property

We lease approximately 60,000 square feet of office space primarily in Texas and Oklahoma under standard office lease arrangements that expire at various dates through April 2008. Our Appalachian division owns a 25,000 square foot of office building in one location and other for its field offices. We believe our facilities are adequate to meet our current needs and existing space could be expanded or additional space could be leased if required. We own various vehicles and other equipment that are used in field operations. We believe such equipment is in good repair and can be readily replaced if necessary.

Title to Properties

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

- customary royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- development obligations under oil and gas leases; and
- burdens such as net profits interests.

ITEM 3. LEGAL PROCEEDINGS

We are involved in various legal actions and claims arising in the ordinary course of business, which include a royalty owner suit filed in 2000 asking for class action certification against us and Great Lakes. In the opinion of management, such litigation and claims are likely to be resolved without a material adverse effect on our financial position or results of operations. See also Note 8 to our consolidated financial statements.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

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

PART II

ITEM 5. MARKET FOR COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

(a) Our common stock is listed on the New York Stock Exchange, or the NYSE, under the symbol “RRC.” During 2004, trading volume averaged 478,745 shares per day. The following table shows the quarterly high and low sale prices, cash dividends declared and volumes as reported on the NYSE composite tape for the past two years.

	High	Low	Cash Dividends Declared	Average Daily Volumes
2003				
First quarter	$ 6.20	$ 5.00	—	136,836
Second quarter	7.43	5.45	—	185,490
Third quarter	7.35	5.98	—	161,659
Fourth quarter	9.86	6.80	.01	232,230
2004				
First quarter	$ 12.15	$ 9.38	—	280,760
Second quarter	14.63	10.79	.01	465,576
Third quarter	17.69	13.54	.01	463,050
Fourth quarter	21.65	14.96	.02	698,995

Between January 1, 2005 and February 26, 2005, the common stock traded at prices between $18.51 and $25.84 per share. Our 7.375% Notes are not listed on an exchange, but trade over-the-counter.

Table of Contents

Holders of Record

At February 26, 2005, there were approximately 2,044 holders of record of our common stock.

Dividends

The payment of dividends is subject to declaration by our board of directors and depends on earnings, capital expenditures and various other factors. The senior credit facility and the 7.375% senior subordinated notes allow for the payment of common and preferred dividends, with certain limitations. In December 2003, we announced we would begin paying cash dividends on our common stock, initially at a quarterly dividend rate of one cent per share. In December 2004, the quarterly common stock dividend was increased to two cents per share.

Equity Compensation Plans

The following table summarizes securities issuable and authorized by the stockholders under certain equity compensation plans (a):

EQUITY COMPENSATION PLAN INFORMATION

	Number of Securities to be issued upon exercise of outstanding options	Weighted average exercise price of outstanding options	Number of securities authorized for future issuance under equity compensation plans
Equity compensation plans approved by security holders (b)	4,582,070	$ 5.39	4,145,605

(a) Although we do not maintain a formal plan, common stock is issued to officers and key employees in lieu of cash for bonuses and matches under our deferred compensation arrangements if elected by employees. All such issuances are approved by the Compensation Committee, which is composed of three independent directors. Issuances to certain of our employees are disclosed in our proxy statements.

(b) There are no equity compensation plans that have not been approved by security holders.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

The following table shows selected financial information for the five years ended December 31, 2004. Significant producing property acquisitions in 2003 and 2004 affect the comparability of year-to-year financial and operating data. See Item 1, "Acquisitions." This information should be read in conjunction with Item 7 of this report "Management's Discussion and Analysis of Financial Condition and Results of Operation," (in thousands, except per share data).

Statement of Operations Data:

	Year Ended December 31,				
	2004	2003	2002	2001	2000
Revenues					
Oil and gas sales	$ 315,703	$ 226,402	$ 190,954	$ 208,854	$ 173,082
Transportation and gathering	2,202	3,509	3,495	3,435	5,306
Gain on retirement of securities	(39)	18,526	3,098	3,951	17,763
Other	2,841	(2,670)	(5,958)	3,375	4,466
	320,707	245,767	191,589	219,615	200,617
Expenses					
Direct operating	46,308	36,423	31,869	34,884	32,457
Production and ad valorem taxes	20,504	12,894	8,574	8,546	8,095
Exploration	21,219	13,946	11,525	5,879	3,187
General and administrative	39,810	24,377	17,240	12,212	14,953
Interest expense and dividends on trust preferred	23,119	22,165	23,153	32,179	39,953
Depletion, depreciation and amortization	99,408	86,549	76,820	77,573	66,968
Provision for impairment	3,563	—	—	31,085	—
	253,931	196,354	169,181	202,358	165,613
Income before income taxes and accounting change	66,776	49,413	22,408	17,257	35,004
Income tax (benefit)					
Current	(245)	170	(4)	(406)	(1,574)
Deferred	24,790	18,319	(3,354)	—	—
	24,545	18,489	(3,358)	(406)	(1,574)
Income before cumulative effect of change in accounting principle	42,231	30,924	25,766	17,663	36,578
Cumulative effect of change in accounting principle, net of taxes	—	4,491	—	—	—
Net income	42,231	35,415	25,766	17,663	36,578
Gain on retirement of preferred stock	—	—	—	556	5,966
Preferred dividends	(5,163)	(803)	—	(10)	(1,554)
Net income available to common stockholders	$ 37,068	$ 34,612	$ 25,766	$ 18,209	$ 40,990
Net income available to common stockholders	$ 0.59	$ 0.56	$ 0.49	$ 0.36	$ 0.97
Cumulative effect of change in accounting principle	—	0.08	—	—	—
Net income per common share	$ 0.59	$ 0.64	$ 0.49	$ 0.36	$ 0.97
Earnings per common share – assuming dilution	$ 0.57	$ 0.53	$ 0.47	$ 0.36	$ 0.96
Cumulative effect of change in accounting principle	—	0.08	—	—	—
Net income per common share – assuming dilution	$ 0.57	$ 0.61	$ 0.47	$ 0.36	$ 0.96

	Year Ended December 31,				
	2004	2003	2002	2001	2000
Balance Sheet Data:					
Current assets(a)	$ 136,336	$ 66,092	$ 50,619	$ 77,735	$ 62,886
Current liabilities(b)	177,162	106,964	67,206	47,879	53,221
Oil and gas properties, net	1,402,359	723,382	564,406	533,357	553,173
Total assets	1,595,406	830,091	658,484	682,462	671,826
Senior debt	423,900	178,200	115,800	95,000	89,900
Non-recourse debt	—	70,000	76,500	98,801	113,009
Subordinated debt	196,656	109,980	90,901	108,690	162,550
Trust preferred securities	—	—	84,840	89,740	92,640
Stockholders' equity(c)	566,340	274,066	206,109	235,621	159,944
Weighted average dilutive shares outstanding	65,332	57,850	54,418	51,265	42,932
Cash dividends declared per common share	.04	.01	—	—	—
Cash Flow Data:					
Net cash provided by operating activities	213,283	125,477	114,472	130,572	74,879
Net cash used in investing activities	(628,335)	(187,635)	(103,950)	(79,163)	(6,014)
Net cash provided by (used in) financing activities	432,803	61,455	(12,568)	(50,641)	(79,257)

(a) 2004 and 2003 include deferred tax assets of $26.3 million and $19.9 million, respectively. 2001 includes a hedging asset of $37.2 million.

(b) 2004, 2003 and 2002 include hedging liabilities of $61.0 million, $54.3 million and $26.0 million, respectively.

(c) Stockholders' equity includes other comprehensive income (loss) of ($43.3 million), ($42.9 million), ($21.2 million), $45.5 million and ($639,000) in 2004, 2003, 2002, 2001 and 2000, respectively.

Table of Contents

The following tables set forth unaudited financial information on a quarterly basis for each of the last two years (in thousands, except per share data):

	2004				
	March	June	September	December	Total
Revenues					
Oil and gas sales	$ 65,368	$ 67,553	$ 85,574	$ 97,208	$ 315,703
Transportation and gathering	467	344	296	1,095	2,202
Gain on retirement of securities	—	(34)	(5)	—	(39)
Other	(2,302)	833	349	3,961	2,841
	63,533	68,696	86,214	102,264	320,707
Expenses					
Direct operating	9,995	10,406	12,718	13,189	46,308
Production and ad valorem taxes	4,250	4,801	5,331	6,122	20,504
Exploration	3,567	4,200	4,615	8,837	21,219
General and administrative	8,821	9,355	10,130	11,504	39,810
Interest expense and dividends on trust preferred	4,145	4,422	6,913	7,639	23,119
Depletion, depreciation and amortization	22,248	22,444	26,306	31,973	102,971
	53,026	55,628	66,013	79,264	253,931
Income before income taxes and accounting change	10,507	13,068	20,201	23,000	66,776
Income tax (benefit)					
Current	—	44	(132)	(157)	(245)
Deferred	3,887	4,835	7,454	8,614	24,790
	3,887	4,879	7,322	8,457	24,545
Net income	6,620	8,189	12,879	14,543	42,231
Preferred dividends	(738)	(737)	(737)	(2,951)	(5,163)
Net income available to common stockholders	$ 5,882	$ 7,452	$ 12,142	$ 11,592	$ 37,068
Net income available to common stockholders	$ 0.11	$ 0.13	$ 0.18	$ 0.17	$ 0.59
Cumulative effect of change in accounting principle	—	—	—	—	—
Net income per common share	$ 0.11	$ 0.13	$ 0.18	$ 0.17	$ 0.59
Earnings per common share – assuming dilution	$ 0.10	$ 0.12	$ 0.17	$ 0.16	$ 0.57
Cumulative effect of change in accounting principle	—	—	—	—	—
Net income per common share – assuming dilution	$ 0.10	$ 0.12	$ 0.17	$ 0.16	$ 0.57

The total of quarterly earnings per share does not necessarily equal the earnings per share for the year, because our convertible securities have not been dilutive in every quarter. (See Item 7 of this report, “Management’s Discussion and Analysis ”).

	2003 March	June	September	December	Total
Revenues					
Oil and gas sales	$ 54,330	$ 55,273	$ 55,723	$ 61,076	$ 226,402
Transportation and gathering	1,027	940	841	701	3,509
Gain on retirement of securities	(315)	(10)	18,572	279	18,526
Other	849	(2,053)	442	(1,908)	(2,670)
	55,891	54,150	75,578	60,148	245,767
Expenses					
Direct operating	9,552	9,542	7,989	9,340	36,423
Production and ad valorem taxes	3,476	3,102	3,131	3,185	12,894
Exploration	2,453	2,687	3,633	5,173	13,946
General and administrative	4,846	5,313	5,493	8,725	24,377
Interest expense and dividends on trust preferred	5,544	5,175	7,705	3,741	22,165
Depletion, depreciation and amortization	20,967	21,276	21,869	22,437	86,549
	46,838	47,095	49,820	52,601	196,354
Income before income taxes and accounting change	9,053	7,055	25,758	7,547	49,413
Income tax (benefit)					
Current	4	(6)	6	166	170
Deferred	4,086	2,470	9,015	2,748	18,319
	4,090	2,464	9,021	2,914	18,489
Income before cumulative effect of change in accounting principle	4,963	4,591	16,737	4,633	30,924
Cumulative effect of change in accounting principle, net of taxes	4,491	—	—	—	4,491
	9,454	4,591	16,737	4,633	35,415
Net income					
Preferred dividends	—	—	(65)	(738)	(803)
Net income available to common stockholders	$ 9,454	$ 4,591	$ 16,672	$ 3,895	$ 34,612
Net income available to common stockholders	$ 0.10	$ 0.08	$ 0.31	$ 0.07	$ 0.56
Cumulative effect of change in accounting principle	0.08	—	—	—	0.08
Net income per common share	$ 0.18	$ 0.08	$ 0.31	$ 0.07	$ 0.64
Earnings per common share – assuming dilution	$ 0.09	$ 0.08	$ 0.29	$ 0.07	$ 0.53
Cumulative effect of change in accounting principle	0.08	—	—	—	0.08
Net income per common share – assuming dilution	$ 0.17	$ 0.08	$ 0.29	$ 0.07	$ 0.61

The total of quarterly earnings per share does not necessarily equal the earnings per share for the year, because our convertible securities have not been dilutive in every quarter (See Item 7 of this report, “Management’s Discussion and Analysis ”).

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (Capitalized terms herein are defined in the footnotes to our consolidated financial statements contained herein.)

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our consolidated financial statements and the accompanying notes included elsewhere in this Form 10-K.

Statements in our discussion may be forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. See Item 1 of this report, "Risk Factors," for additional discussion of some of these factors and risks.

Overview

We are an independent natural gas and oil company engaged in the exploration, development and acquisition of oil and gas properties, primarily in the Southwestern, Appalachian and Gulf Coast regions of the United States. We operate in one segment as each of our operations areas has similar economics characteristics and each meets the criteria for aggregation as defined in Statement of Financial Accounting Standards No. 131, "Disclosure about segments of an enterprise and related information."

We seek to increase reserves and production through internally generated drilling projects coupled with complementary acquisitions. Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and on our ability to find, develop and acquire oil and gas reserves that are economically recoverable.

During 2004, we achieved the following results:

- 72% reserve growth and 24% production growth
- Positive financial results
- Favorable drilling results
- Complementary acquisitions completed
- Balance sheet simplified
- Drilling inventory expanded, coalbed methane and shale plays added

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements which have been prepared in accordance with accounting principles generally adopted in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the amounts reported in the financial statements and related footnote disclosures. Application of certain of our accounting policies, including those related to oil and gas revenues, bad debts, the fair value of derivatives, oil and gas properties, asset retirement obligations, marketable securities, income taxes and contingencies and litigation require significant estimates. We base our estimates on historical experience and various assumptions that are believed reasonable under the circumstances. Actual results may differ from these estimates. We believe the following critical accounting policies reflect our more significant judgments and estimates used in the preparation of our financial statements.

Property, Plant and Equipment

Proved reserves are defined by the SEC as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although our engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, the estimation of reserves requires engineers to make a significant number of assumptions based on professional judgment. Reserve estimates are updated at least annually and consider recent production levels and other technical information. Estimated reserves are often subject to future revision, which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price and cost changes and other economic factors. Changes in oil and gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions in turn cause adjustments in the depletion rates utilized by us. We cannot predict what reserve revisions may be required in future periods. Reserve estimates are reviewed and approved by our Vice President of Reservoir Engineering who reports directly to our Chief Operating Officer. In addition, because substantially all of our proved reserves are pledged as collateral for our senior credit facility, our estimates of proved reserves are reviewed twice annually by independent engineers on behalf of each of the sixteen banks participating in our senior credit facility. To further ensure the reliability of reserve estimates, we engage independent petroleum consultants to review the estimates of proved reserves.

The following table sets forth a summary of the reserves which were reviewed by independent petroleum consultants for each of the years ended 2004, 2003 and 2002.

Audited (a)		
2004	2003	2002
88%	87%	84%

(a) Audited reserves are those quantities which were estimated by our employees and reviewed by an independent petroleum consultant.

We utilize the successful efforts method to account for exploration and development expenditures. Unsuccessful exploration wells are expensed and can have a significant effect on reported operating results. Successful exploration drilling costs and all development costs are capitalized and systematically charged to expense using the units of production method based on proved oil and gas reserves as estimated by our engineers. The successful efforts method inherently relies upon the estimation of proved reserves, which includes proved developed and proved undeveloped volumes.

We adhere to statement of Financial Accounting Standards No. 19 (“SFAS 19”) for recognizing any impairment of capitalized costs to unproved properties. The greatest portion of these costs generally relate to the acquisition of leasehold costs. The costs are capitalized and periodically evaluated as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. We consider a combination of time, geologic and engineering factors to evaluate the need for impairment of these costs. Unproved properties had a net book value of $14.8 million, $12.2 million and $19.0 million in 2004, 2003 and 2002, respectively.

Depletion rates are determined based on reserve quantity estimates and the capitalized costs of producing properties. As the estimated reserves are adjusted, the depletion expense for a property will change, assuming no change in production volumes or the costs capitalized. Estimated reserves are used as the basis for calculating the expected future cash flows from a property, which are used to determine whether that property may be impaired. Reserves are also used to estimate the supplemental disclosure of the standardized measure of discounted future net cash flows relating to oil and gas producing activities and reserve quantities disclosure in Note 18, “Unaudited Supplemental Reserve Information” to our consolidated financial statements. Changes in the estimated reserves are considered in estimates for accounting purposes and are reflected on a prospective basis.

We monitor our long-lived assets recorded in property, plant and equipment in our consolidated balance sheet to ensure they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the ultimate amount of recoverable oil and gas reserves that will be produced from a field, the timing of future production, future production costs, future abandonment costs, and future inflation. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or gas, unfavorable adjustment to reserves, physical damage to production equipment and facilities, a change in costs, or other changes to contracts, environmental regulations or tax laws. All of these factors must be considered when testing a property's carrying value for impairment. We cannot predict whether impairment charges may be required in the future. We had an impairment of $3.6 million in 2004 on an offshore property.

Derivatives

We use commodity derivative contracts to manage our exposure to oil and gas price volatility. We account for our commodity derivatives in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"). Earnings are affected by the ineffective portion of a hedge contract (changes in realized prices that do not match the changes in the hedge price). Ineffective gains or losses are recorded in other revenue while the hedge contract is open and may increase or reverse until settlement of the contract. This may result in significant volatility to current period income. For derivatives qualifying as hedges, the effective portion of any changes in fair value is recognized in stockholders' equity as other comprehensive income, or OCI, and then reclassified to earnings, in oil and gas revenue, when the transaction is consummated. This may result in significant volatility in stockholders' equity. The fair value of open hedging contracts is an estimated amount that could be realized upon termination.

The commodity derivatives we use include commodity collars and swaps. While there is a risk that the financial benefit or rising prices may not be captured, we believe the benefits of stable and predictable cash flow are more important. Among these benefits are: more efficient utilization of existing personnel and planning for future staff additions, the flexibility to enter into long-term projects requiring substantial committed capital, smoother and more efficient execution of our ongoing development drilling and production enhancement programs, more consistent returns on invested capital, and better access to bank and other credit markets. We also have some interest rate swap agreements to protect against the volatility of variable interest rates under our senior credit facility.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and restore land or seabed at the end of oil and gas production operations. Removal and restoration obligations are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and gas platforms. Estimating the future asset removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as well as regulatory, political, environmental, safety and public relations considerations.

Asset retirement obligations are not unique to us or to the oil and gas industry and in 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," ("SFAS 143"). We adopted this statement effective January 1, 2003, as discussed in Note 4, "Asset Retirement Obligations," to our consolidated financial statements. SFAS 143 significantly changed the method of accruing for costs that an entity is legally obligated to incur related to the retirement of fixed assets ("asset retirement obligations" or "ARO"). Primarily, the statement requires us to record a separate liability for the fair value of our asset retirement obligations, with an offsetting increase to the related oil and gas properties on our consolidated balance sheet.

Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate retirement costs, inflation factors, credit adjusted discount rates, timing of retirement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance. In addition, increases in the discounted ARO liability resulting from the passage of time are reflected as accretion expense in our consolidated statement of operations.

SFAS 143 required a cumulative adjustment to reflect the impact of implementing the statement had the rule been in effect since inception. We calculated the cumulative accretion expense on the ARO liability and the cumulative depletion expense on the corresponding property balance. The sum of this cumulative expense was compared to the depletion expense originally recorded. Because the historically recorded depletion expense was higher than the cumulative expense calculated under SFAS 143, the difference resulted in a $4.5 million gain, net of tax, which we recorded as cumulative effect of change in accounting principle on January 1, 2003.

Deferred Taxes

We are subject to income and other taxes in all areas in which we operate. When recording income tax expense, certain estimates are required because: (a) income tax returns are generally filed many months after the close of a calendar year; (b) tax returns are subject to audit which can take years to complete; and (c) future events often impact the timing of when income tax expenses and benefits are recognized. We have deferred tax assets relating to tax operating loss carryovers and other deductible differences. We routinely evaluate all deferred tax assets to determine the likelihood of realization. A valuation allowance is recognized on deferred tax assets when we believe that certain of these assets are not likely to be realized.

In determining deferred tax liabilities, accounting rules require OCI to be considered, even though such income (loss) has not yet been earned. At year-end 2003, deferred tax assets exceeded deferred tax liabilities by $9.0 million with $24.6 million of deferred tax assets related to unrealized deferred hedging losses included in OCI. At year-end 2004, deferred tax liabilities exceeded deferred tax assets by $91.4 million with $26.0 million of deferred tax assets related to unrealized deferred hedging losses included in OCI. Based on our projected profitability and because if prices remain constant, the unrealized hedging losses should be offset in the future by higher realization on our production, no year-end 2004 valuation allowance was deemed necessary.

We may be challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions on our various income tax returns. Although we believe that we have adequately provided for all taxes, gains or losses could occur in the future due to changes in estimates or resolution of outstanding tax matters.

Contingent Liabilities

A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost or range of cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and contingent matters. In addition, we often must estimate the amount of such losses. In many cases, our judgment is based on the input of our legal advisors and on the interpretation of laws and regulations, which can be interpreted differently by regulators and/or the courts. We monitor known and potential legal, environmental and other contingent matters and make our best estimate of when to record losses for these matters based on available information. Although we continue to monitor all contingencies closely, particularly our outstanding litigation, we currently have no material accruals for contingent liabilities.

Bad Debt Expense

We periodically assess the recoverability of all material trade and other receivables to determine their collectability. At Independent Producer Finance, or IPF, receivables are evaluated quarterly and provisions for uncollectible amounts are established. Such provisions for uncollectible amounts are recorded when management believes that a related receivable is not recoverable based on current estimates of expected discounted cash flows and other factors which could affect the collection.

Revenues

We recognize revenues from the sale of products and services in the period delivered. We use the sales method to account for gas imbalances, recognizing revenue based on cash received rather than gas produced. Revenues are sensitive to changes in prices received for our products. A substantial portion of production is sold at prevailing market prices, which fluctuate in response to many factors that are outside of our control. Changes in the supply and demand for oil and natural gas can have dramatic effects on prices. Political instability and availability of alternative fuels could impact worldwide supply, while economic factors can impact demand. At IPF, payments believed to relate to return are recognized as income. Currently, all IPF receipts are being recognized as a return of capital.

Other

We record a write down of marketable securities when the decline in market value is considered to be other than temporary. Third party reimbursements for administrative overhead costs incurred due to our role as operator of oil and gas properties are applied to reduce general and administrative expense. Salaries and other employment costs of those employees working on our exploration efforts are expensed as exploration expense. We do not capitalize general and administrative expense or interest expense.

Recent Accounting Pronouncements

On December 16, 2004, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 123 (revised 2004), Share-Based Payment which is a revision of FASB Statement No. 123, Accounting for Stock-Based Compensation. Statement 123(R) supercedes APB opinion No. 25, Accounting for Stock Issued to employees, and amends FASB Statement No. 95, Statement of Cash Flows. Generally, the approach in Statement 123(R) is similar to the approach described in Statement 123. However, Statement 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their fair values. Pro forma disclosure is no longer an alternative. The provisions of this statement become effective for our third quarter 2005. Management has not determined the impact that this statement will have on our consolidated financial statements.

In December 2004, the Financial Accounting Standards Board issued a FASB Staff Position (FSP) that provides accounting guidance on how companies should account for the effects of the American Jobs Creation Act of 2004 that was signed into law on October 22, 2004. FSP FAS 109-1, “Application of FASB Statement No. 109, “Accounting for Income Taxes,” to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004,” states that the manufacturers’ deduction provided for under this legislation should be accounted for as a special deduction instead of a tax rate change. The FSP may affect how a company accounts for deferred income taxes. The FSP is effective December 31, 2004. We are currently evaluating the impact from the FSP on our results of operations and financial position and we expect to complete our evaluation during the first half of fiscal 2005.

FACTORS AFFECTING FINANCIAL CONDITION AND LIQUIDITY

Liquidity and Capital Resources

During 2004, we spent $832.9 million on acquisitions, development and exploration. Acquisition expenditures were primarily comprised of $310.7 million for the 50% of Great Lakes we did not own and $297.8 million for the Pine Mountain acquisition. See footnote 16 to our consolidated financial statements. At December 31, 2004, we had $18.4 million in cash, including $17.3 million of cash proceeds held in escrow to be used to purchase similar assets and $1.6 billion of total assets. Total capitalization was $1.2 billion, of which 48% was represented by stockholder equity and 52% by debt. At December 31, 2004, we had a working capital deficit of $40.8 million which included an unrealized hedging liability of $61.0 million due to the mark-to-market of all open hedges. Because payments on this hedging liability are made monthly and we will also collect production proceeds to which this hedging relates, the amount should be self-funding.

Cash is required to fund capital expenditures necessary to offset inherent declines in production and proven reserves which is typical in the capital intensive extractive industry. Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We believe that net cash generated from operating activities and unused committed borrowing capacity under the senior credit facility combined with our oil and gas price hedges currently in place will be adequate to satisfy near term financial obligations and liquidity needs. However, long-term cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the oil and gas business. A material drop in oil and gas prices or a reduction in production and reserves would reduce our ability to fund capital expenditures, reduce debt, meet financial obligations and remain profitable. We operate in an environment with numerous financial and operating risks, including, but not limited to, the inherent risks of the search for, development and production of oil and gas, the ability to buy properties and sell production at prices which provide an attractive return and the highly competitive nature of the industry. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, borrowings or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to offset inherent declines in production and proved reserves.

In 2004, we filed a new universal shelf registration statement with the SEC registering $500.0 million aggregate amount of common stock, preferred stock and other equity and debt securities. In December 2004, we issued 5.75 million shares of common stock under this shelf registration statement for an aggregate price of $107.8 million. As of December 31, 2004, we have $392.2 million of capacity remaining under the shelf.

The following summarizes our contractual financial obligations at December 31, 2004 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities and refinancing proceeds.

	Payment due by period				
	2005	2006 and 2007	2008 and 2009	Thereafter	Total
			(in thousands)		
Long-term debt	$ —	$ —	$ 423,900[a]	$ 200,000	$ 623,900
Interest on 7.375% notes	14,750	29,500	29,500	59,000	132,750
Capital leases	11	5	—	—	16
Operating leases	2,745	2,394	388	—	5,527
Seismic purchase	215	—	—	—	215
Derivative obligations[b]	60,471	10,720	—	—	71,191
Asset retirement obligation liability	6,822	14,502	13,295	36,108	70,727
Total contractual obligations[c]	$ 85,014	$ 57,121	$ 467,083	$ 295,108	$ 904,326

(a)Due at termination date of our senior credit facility, which we expect to renew, but there is no assurance that can be accomplished. Interest paid on the senior credit facility would be approximately $16.5 million each year assuming no change in the interest rate or outstanding balance.

(b)Derivative obligations represent net open hedging contracts valued as of December 31, 2004.

(c)This table does not include the liability for the deferred compensation plan since these obligations will be funded with existing plan assets.

Bank Credit Facility

We maintain a $600.0 million revolving credit facility, which we refer to as our Senior Credit Facility. The Senior Credit Facility is secured by substantially all of our assets and matures on January 1, 2008. Availability under the Senior Credit Facility is subject to a borrowing base set by the banks semi-annually and more often in certain other circumstances. The borrowing base is dependent on a number of factors, primarily the lenders' assessment of future cash flows. Redeterminations of the borrowing base require approval of 75% of the lenders; increases require unanimous approval. At February 26, 2005, the Senior Credit Facility had a $575.0 million borrowing base of which $134.5 million was available.

Restrictions on the payment of dividends and other restricted payments as defined are imposed under the our Senior Credit Facility and the 7.375% Notes. Under the Senior Credit Facility, common and preferred dividends are permitted. The terms of the 7.375% Notes limit restricted payments (including dividends) to the greater of $20.0 million or a formula based on earnings since the issuance of the notes. At December 31, 2004, approximately $266.9 million was available under the 7.375% Notes restricted basket. The Senior Credit Facility provides for a restricted payment basket of $20.0 million plus 66-2/3% of net cash proceeds from common stock issuances and 50% of net income. Approximately $250.3 million was available under the Senior Credit Facility basket as of December 31, 2004. The debt agreements contain customary qualitative covenants relating to debt incurrence, working capital, dividends and a debt to earnings ratio. We were in compliance with all covenants at December 31, 2004.

Cash Dividend Payments

In December 2003, we announced the reinstatement of cash dividends on our common stock at an initial quarterly dividend rate of one cent per share. The first dividend was paid on January 30, 2004. A one cent per share dividend was declared in the second and third quarters of 2004. On December 1, 2004, a two cent per share dividend was declared and paid on December 31, 2004. The payment of dividends is subject to declaration by our board of directors and depends on earnings, capital expenditures and various other factors, such as restrictions under our Senior Credit Facility and the 7.375% Notes discussed above. Preferred dividends of $738,000, $737,000, $737,000 and $738,000 were paid in the first, second, third and fourth quarters of 2004. In addition, $2.2 million of preferred dividend was accrued at December 31, 2004 related to the conversion of the 5.9% Convertible Preferred Stock.

Cash Flow

Our principal sources of cash are operating cash flow, bank borrowings and at times, issuance of debt and equity securities. Our operating cash flow is highly dependent on oil and gas prices. As of December 31, 2004, we had entered into hedging agreements covering 56.6 Bcfe and 22.5 Bcfe for 2005 and 2006, respectively. The $174.8 million of cash capital expenditures for 2004, excluding acquisitions, was funded with internal cash flow. The $254.0 million 2005 capital budget, which excludes acquisitions, is expected to increase production and to expand the reserve base. Based on current projections, oil and gas futures prices and our hedge position, the 2005 capital program is expected to be funded with internal cash flow.

Net cash provided by operations in 2004, 2003 and 2002 was $213.3 million, $125.5 million and $114.5 million respectively. In 2004, cash flow from operations increased due to higher volumes and prices partially offset by increasing operating and exploration expenses. In 2003, cash flow from operations increased with higher volumes and higher prices partially offset by increasing operating and exploration expenses. In 2002, cash flow from operations decreased due to lower prices and volumes, higher exploration and higher general and administrative expenses. This decrease was partially offset by lower interest expenses and direct operating expenses.

Net cash used in investing activities in 2004, 2003 and 2002 was $628.3 million, $187.6 million and $104.0 million, respectively. The 2004 period included $170.6 million in additions to oil and gas properties and $485.6 million of acquisitions. The 2003 period included $92.0 million in additions to oil and gas properties, and $103.9 million of acquisitions, partially offset by $12.1 million of IPF receipts. The 2002 period included $92.6 million in additions to oil and gas properties and $5.1 million of IPF investments partially offset by $17.3 million of IPF receipts.

Net cash provided by (used in) financing activities in 2004, 2003 and 2002 was $432.8 million, $61.5 million and ($12.6 million), respectively. Historically, sources of financing have been primarily bank borrowings and capital raised through equity and debt offerings. During 2004, we received proceeds of $98.1 million and $250.5 million from the issuance of additional 7-3/8% Notes and two common stock offerings, respectively. During 2004, the outstanding balance under our Senior Credit Facility increased $245.7 million with $70.0 million related to the Great Lakes transaction and the remaining increase the result of funding other acquisitions. Also in 2004, we redeemed the remaining outstanding 6% Debentures for $11.6 million. During 2003, the outstanding balance under our Senior Credit Facility increased $62.4 million primarily due to the December acquisition of producing properties in the Conger field. In 2003, total debt declined $9.9 million. During 2003, we redeemed $84.8 million of the Trust Preferred Securities and $69.3 million of the 8.75% Notes and issued $100.0 million of 7.375% Notes. During 2002, the outstanding balance under our Senior Credit Facility increased $20.8 million and total debt (including Trust Preferred Securities) decreased by $24.2 million.

Capital Requirements

Our primary needs for cash are for exploration, development and acquisition of oil and gas properties, repayment of principal and interest on outstanding debt and payment of dividends. During 2004, $174.8 million of capital was expended, primarily on drilling projects. Also during 2004, $485.6 million was expended on acquisitions, including $470.1 million to purchase producing properties and $15.5 million to purchase gathering facilities. The capital program, excluding acquisitions, was funded by net cash flow from operations. The 2005 capital budget of $254.0 million, excluding acquisitions, is expected to be funded by cash flow from operations. Development and exploration activities are highly discretionary, and, for the foreseeable future, we expect such activities to be maintained at levels equal to or below internal cash flow. To the extent capital requirements exceed internal cash flow, debt or equity may be issued to fund these requirements. We currently believe we have sufficient liquidity and cash flow to meet our obligations for the next twelve months; however, a drop in oil and gas prices or a reduction in production or reserves could adversely affect our ability to fund capital expenditures and meet our financial obligations. Also, our obligations may change due to acquisitions, divestitures and continued growth. We may issue additional shares of stock, subordinated notes or other debt securities to fund capital expenditures, acquisitions, extend maturities or to repay debt.

Hedging – Oil and Gas Prices

We enter into hedging agreements to reduce the impact of oil and gas price volatility on our operations. At December 31, 2004, hedges were in place covering 19.7 Bcf of gas at prices averaging $4.25 per mcf, 0.6 million barrels of oil at prices averaging $28.95 per barrel and 0.2 million barrels of NGLs at prices averaging $19.20 per barrel. We also had collars covering 37.8 Bcf of gas at weighted average floor and cap prices of $5.03 to $7.18 and 2.8 million barrels of oil at weighted average floor and cap prices of $29.84 to $38.66. The hedges' fair value, represented by the estimated amount that would be realized or payable on termination, based on a comparison of the contract price and a reference price, generally NYMEX, approximated a pretax loss of $71.9 million at December 31, 2004. The contracts expire monthly through December 2006. Transaction gains and losses are determined monthly and are included as increases or decreases on oil and gas revenue in the period the hedged production is sold. A hedging gain of $17.8 million was realized in 2002. Hedging losses of $60.4 million and $100.1 million were realized in 2003 and 2004, respectively. Changes in the value of the ineffective portion of all open hedges are recognized in earnings quarterly in other income. Since 2001, unrealized gains or losses on hedging positions are recorded at an estimate of fair value based on a comparison of the contract price and a reference price, generally NYMEX, on our consolidated balance sheet as OCI, a component of stockholders' equity.

At December 31, 2004, the following commodity derivative contracts were outstanding:

Contract Type	Period	Volume Hedged	Average Hedge Price
Natural gas			
Swaps	2005	50,695 Mmbtu/day	$ 4.21
Swaps	2006	3,288 Mmbtu/day	$ 4.85
Collars	2005	67,175 Mmbtu/day	$5.25-$ 7.18
Collars	2006	36,363 Mmbtu/day	$5.03-$ 6.97
Crude Oil			
Swaps	2005	1,146 bbl/day	$ 26.84
Swaps	2006	400 bbl/day	$35.00
Collars	2005	4,415 bbl/day	$29.84-$37.05
Collars	2006	3,264 bbl/day	$31.53-$38.66
Natural gas liquids			
Swaps	2005	658 bbl/day	$ 19.20

Interest Rates

At December 31, 2004, we had $620.6 million of debt outstanding. Of this amount, $196.7 million bears interest at a fixed rate of 7.375%. Senior debt totaling $423.9 million bears interest at floating rates, which average 3.9% at year-end 2004, excluding interest rate swaps. At December 31, 2004, we had $45.0 million subject to fixed for floating interest rate swap agreements. These swaps consist of one agreement for $10.0 million at 1.4% which expires in June 2005 and two agreements totaling $35.0 million at 1.8% which expire in June 2006. The 30-day LIBOR rate on December 31, 2004 was 2.4%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2004 would cost us approximately $3.8 million in additional annual interest, net of swaps.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements that are material to our financial position or results of operations.

Inflation and Changes in Prices

Our revenues, the value of our assets, our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in oil and gas prices. Oil and gas prices are subject to significant fluctuations that are beyond our ability to control or predict. Although certain of our costs and expenses are affected by general inflation, inflation does not normally have a significant effect on us. However, industry-specific inflationary pressures built up over an 18-month period in 2001 and early 2002 due to favorable conditions in the industry. During 2002, we experienced a slight decline in certain drilling and operational costs when compared to the prior-year and in 2003 there were slight increases in these costs. In 2004, we experienced an overall increase in drilling costs compared to 2003 especially with regard to steel products. We expect further increases in these costs for 2005. Increases in commodity prices can cause inflationary pressures specific to the industry to also increase.

The following table indicates the average oil and gas prices received over the last five years and quarterly for 2004, 2003 and 2002. Average price calculations exclude hedging gains and losses. Oil is converted to natural gas equivalents at the rate of one barrel per six mcf.

	Average Prices (Excluding Hedging)		
	Oil (Per Bbl)	Natural Gas (Per Mcf)	Equivalent Mcf (Per Mcfe)
Annual			
2004	$ 39.25	$ 5.79	$ 5.80
2003	28.42	5.10	4.94
2002	23.34	3.02	3.16
2001	23.34	3.91	3.87
2000	28.15	3.71	3.90
Quarterly			
2004			
First	$ 32.15	$ 5.21	$ 5.10
Second	35.87	5.56	5.49
Third	40.99	5.59	5.70
Fourth	45.85	6.66	6.72
2003			
First	$ 31.44	$ 6.08	$ 5.79
Second	26.71	5.15	4.90
Third	27.42	4.75	4.64
Fourth	28.27	4.51	4.49
2002			
First	$ 18.80	$ 2.28	$ 2.43
Second	23.09	3.20	3.28
Third	25.43	2.99	3.21
Fourth	25.57	3.63	3.72

Industry Environment

We operate entirely within the United States, a mature region for the exploration and production of oil and gas. As a mature region, while new discoveries of oil and gas occur in the United States, the size and frequency of these discoveries is declining. We believe that there remain areas of the United States, such as the Appalachian basin and certain areas in our Southwestern division, that are underexplored and have not been fully explored with the benefit of newly available exploration, production and reserve enhancement technology. Examples of such technology include advanced 3D seismic processing, hydraulic reservoir fracture stimulation, advances in well logging and analysis, horizontal drilling and completion techniques, secondary and tertiary recovery practices, and automated remote well monitoring and control devices.

Another characteristic of a mature region is the exit of larger independent producers and the major oil companies from such regions. These companies, searching for ever larger new discoveries, have ventured increasingly overseas and offshore, de-emphasizing their onshore United States assets. This movement out of mature basins by larger companies has provided attractive acquisition opportunities for companies like ours that maintain well equipped technical teams capable of generating additional value from these assets. In other situations, to increase cash flow without increasing capital spending, larger independent producers and major integrated oil companies have allowed smaller companies the opportunity to explore and develop reserves on their undeveloped acreage through joint ventures. We acquired approximately 70,000 acres in 2004 for our Southwestern division from such arrangements.

Table of Contents

Results of Operations

Volumes and Sales Data

	2004	2003	2002
Production:			
Crude oil (bbls)	2,512,434	2,023,158	1,872,654
NGLs (bbls)	988,192	400,631	406,746
Natural gas (mcfs)	50,722,121	43,510,180	41,095,976
Total (mcfe)(a)	71,725,877	58,052,911	54,772,376
Average daily production:			
Crude oil (bbls)	6,865	5,543	5,131
NGLs (bbls)	2,700	1,098	1,114
Natural gas (mcfs)	138,585	119,206	112,592
Total (mcfe)(a)	195,972	159,049	150,061
Average sales prices (excluding hedging):			
Crude oil (per bbl)	$ 39.25	$ 28.42	$ 23.34
NGLs (per bbl)	23.73	18.75	12.93
Natural gas (per mcf)	5.79	5.10	3.02
Total (mcfe)(a)	5.80	4.94	3.16
Average sales prices (including hedging):			
Crude oil (per bbl)	$ 28.04	$ 23.53	$ 22.25
NGLs (per bbl)	19.76	18.75	12.93
Natural gas (per mcf)	4.45	3.94	3.50
Total (per mcfe)(a)	4.40	3.90	3.49

(a) Oil and NGLs are converted to natural gas equivalents at the rate of one barrel per six mcf.

Table of Contents

The following table identifies certain items included in the results of operations and is presented to assist in comparing results of the last three years. The table should be read in conjunction with the following discussions of results of operations.

	Year Ended December 31, 2004	2003	2002
		(in thousands)	
Increase (decrease) in revenues			
Write-down of marketable securities	$ —	$ —	$ (1,220)
Gain (loss) on retirement of securities	(39)	18,526	3,098
Gain/(loss) on asset sales	5,001	(15)	161
Ineffective portion of commodity hedges gain (loss)	712	(1,238)	(2,730)
Realized hedging gains (losses)	(100,121)	(60,427)	17,790
Insurance claim valuation	(1,968)	—	—
Recovery from arbitration	—	—	715
	(96,415)	$ (43,154)	$ 17,814
Increase (decrease) in expenses			
Provision for impairment	$ 3,563	$ —	$ —
Mark-to-market deferred compensation expense[a]	19,176	6,559	1,023
Bad debt expense accrual	—	275	150
Non-qualifying interest rate swaps	(1,073)	(559)	275
Call premium on 6% Debentures	178	—	—
Call premium on 8.75% Notes	—	2,006	—
Adjustment of IPF valuation allowance	1,156	1,739	4,240
	$ 23,000	$ 10,020	$ 5,688
Cumulative effect of change in accounting principle (net of taxes)	$ —	$ 4,491	$ —

(a) Represents the mark-to-market expense related to our stock and marketable securities held in the deferred compensation plan.

Overview

Our 2004 performance reflects the benefit of higher oil and gas production, higher oil and gas prices, and continued focus upon our cost structure. The business of exploring for, developing, and acquiring oil and gas is highly competitive and capital intensive. As in any commodity business, the costs associated with finding, acquiring, extracting, and financing the operation are critical to profitability and long-term value creation for stockholders and generating meaningful growth while containing costs represents an ongoing challenge for management. During periods of historically high oil and gas prices, such as 2004, cost increases are more prevalent due to increased competition for goods and services. We faced other challenges in 2004 include attracting and retaining qualified personnel, consummating and integrating acquisitions, and accessing the capital markets to fund our growth and capital simplification process on sufficiently favorable terms.

We have continued to expand and improve the technical staff through the hiring of additional experienced professionals. Also, acquisitions completed in late 2003 and 2004 have added experienced professionals to our teams. The inventory of exploration and development prospects continues to expand, providing promising new growth opportunities, greater diversification of technical risk, and better efficiency.

Our balance sheet was further simplified in 2004 with the retirement of the 6% convertible subordinated notes and the elimination of the Great Lakes bank credit facility. Lastly, the 5.9% convertible preferred stock was converted to common stock in December of 2004. Our capital structure now consists of bank debt, senior subordinated notes and common equity.

Comparison of 2004 to 2003

Net income increased $6.8 million, with higher average oil and gas prices and volumes as a primary factor contributing to this increase. Increased revenues were partially offset by higher operating costs and higher DD&A. The year ended 2003 included an $18.5 million gain on retirement of debt and convertible securities versus a loss of $39,000 in 2004. The year ended 2003 also included a $4.5 million favorable cumulative effect of change in accounting principle.

Average realized price received for oil and gas during 2004 was $4.40 per mcfe, up 13% or $0.50 per mcfe from 2003. Oil and gas revenues for 2004 reached a record $315.7 million and were 39% higher than 2003 due to higher oil and gas prices and a 24% increase in production. The average price received increased 19% to $28.04 per barrel for oil and increased 13% to $4.45 per mcf for gas from 2003. The effect of our hedging program decreased realized prices $1.40 per mcfe in 2004 versus a decrease of $1.04 in 2003.

Production volume increased 24% from 2003 due to our drilling program and additions from acquisitions consummated in late 2003 and 2004, primarily the Conger Field acquisition in 2003 and our purchase of the 50% of Great Lakes that we did not own in 2004. Production increased 13.7 Mmcfe from 2003. Our production volumes increased 56% in our Appalachian Division, increased 30% in our Southwestern division and declined 14% in our Gulf Coast division.

Transportation and gathering revenue of $2.2 million declined $1.3 million from 2003. This decline is due to lower oil marketing revenues and additional gas transportation system employee expense related to the Conger Field acquisition ($1.1 million) partially offset by additional revenue related to the Great Lakes acquisition.

Gain (loss) on retirement of securities was a loss of $39,000 in 2004 versus a gain of $19.0 million in 2003. The year ended 2004 includes the purchase for cash of $2.7 million of 6% Debentures. During 2003, 129,000 shares of common stock were exchanged for $880,000 of 6% Debentures with a conversion expense of $465,000 recorded on the exchange. In addition, 2003 included $9.1 million of 6% Debentures, $500,000 of 8.75% Notes and $5.3 million of Trust Preferred Securities were repurchased for cash. Also in 2003, $10.2 million of cash and $50.0 million of our newly issued Convertible Preferred was exchanged for $79.5 million of Trust Preferred Securities.

Other revenue increased in 2004 to $2.8 million from a loss of $2.7 million in 2003. The 2004 period includes a gain on the sale of properties of $5.0 million and $712,000 of ineffective hedging gains offset by $2.0 million write-down of an insurance claim receivable. Other revenue for 2004 also includes net IPF expenses of $1.8 million. Other revenue in 2003 includes an ineffective hedging loss of $1.2 million and net IPF expenses of $1.4 million.

Direct operating expense increased $9.9 million to $46.3 million due to increased costs from acquisitions and higher oilfield service costs. Our operating expenses are increasing as we add new wells and maintain production from our existing properties. We incurred $1.8 million of expenses associated with workovers in 2004 versus $2.7 million in 2003. On a per mcfe basis, direct operating expenses increased $0.02 per mcfe with higher field level costs offset by lower workover costs.

Production and ad valorem taxes are paid based on market prices and not hedged prices. These taxes increased $7.6 million or 59% from the same period of the prior year. On a per mcfe basis, production and ad valorem taxes increased from $0.22 per mcfe to $0.29 per mcfe due to higher market prices.

Exploration expense increased 52% to $21.2 million due to higher dry hole costs ($8.5 million) and higher personnel costs partially offset by lower seismic purchases ($2.6 million). Exploration expense includes exploration personnel costs of $4.4 million in 2004 versus $3.3 million in 2003.

General and administrative expense for 2004 increased 63% or $15.4 million from 2003 due primarily to an $12.6 million increase in the non-cash mark-to-market expense relating to the deferred compensation plan. This non-cash expense relates to the increase in value of our common stock and other investments held in our deferred compensation plan. Our common stock price increased from $9.45 per share at the end of 2003 to $20.46 per share at the end of 2004. We also incurred higher professional fees and additional personnel costs due to the Great Lakes acquisition. On a per mcfe basis, excluding the mark-to-market on the deferred compensation plan, general and administration expense declined from $0.31 per mcfe in 2003 to $0.29 per mcfe in 2004.

Interest expense for 2004 increased $1.0 million or 4%, to $23.1 million with higher interest rates and average debt balance partially offset by a lower call premiums of $1.8 million. Interest expense for 2003 included a $2.0 million call premium on the 8.75% Notes. Average debt outstanding on the Senior Credit Facility was $262.4 million and $104.7 million for 2004 and 2003, respectively and the average interest rates were 3.3% and 3.1%, respectively.

Depletion, depreciation and amortization (or "DD&A") increased $16.4 million or 19% to $103.0 million due to higher production and a $3.6 million (or $0.05 per mcfe) impairment charge on an offshore property in our Gulf Coast division. The impairment was attributable to hurricane damage and related production declines. On a per mcfe basis, excluding the impairment charge on the offshore property, DD&A declined from $1.49 per mcfe to $1.39 per mcfe. For 2005, based on our current reserve base, we expect our DD&A rate to average $1.45 per mcfe.

Tax expense for 2004 increased $6.1 million, or 33%, over 2003 due to a 35% increase in income before taxes. Year-end 2004 and 2003 provide for a tax rate of 37%. Given our available net operating loss carryforward, we do not expect to pay significant cash federal income taxes.

The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2004.

Operating expenses per mcfe	2004	2003	Change
Direct operating expense	$ 0.65	$ 0.63	$ 0.02
Production and ad valorem tax expense	0.29	0.22	0.07
General and administration expense (excluding non-cash mark-to-market on deferred compensation plan)	0.29	0.31	(0.02)
Depletion, depreciation and amortization expense (excluding impairment)	1.39	1.49	(0.10)

Comparison of 2003 to 2002

Net income increased $9.6 million as a result of higher oil and gas prices and volumes, partially offset by higher operating, exploration and general and administrative costs and higher DD&A. The year ended 2003 included an $18.5 million gain on retirement of debt and convertible securities versus a $3.1 million gain in 2002 and a $4.5 million favorable cumulative effect of change in accounting principle.

Average realized price received for oil and gas during 2003 was $3.90 per mcfe, up 12% or $0.41 per mcfe from 2002. Oil and gas revenues for 2003 reached $226.4 million and were 19% higher than 2002 due to higher oil and gas prices and a 6% increase in production. The average price received increased 6% to $23.53 per barrel for oil and increased 13% to $3.94 per mcf for gas from 2002. The effect of our hedging program decreased realized prices $1.04 per mcfe in 2003 versus an increase of $0.33 in 2002.

Production volume increased 6% during 2003 primarily through drilling activities on existing and newly acquired acreage acquisitions. Production increased 3.3 Mmcfe from 2002. Our production volumes increased 9% in our Southwestern division, increased 5% in our Appalachian division and declined 8% in our Gulf Coast division.

Gain (loss) on retirement of securities was a gain of $18.5 million in 2003 versus $3.1 million in 2002. During 2003, 129,000 shares of common stock were exchanged for $880,000 of 6% Debentures. A conversion expense of $465,000 was recorded on the exchange. In addition, $9.1 million of 6% Debentures, $500,000 of 8.75% Notes and $5.3 million of Trust Preferred Securities were repurchased for cash. Also in 2003, $10.2 million of cash and $50.0 million of our newly issued Convertible Preferred was exchanged for $79.5 million of Trust Preferred Securities. In 2002, 1.6 million shares of common stock were exchanged for $2.4 million of Trust Preferred Securities, $7.1 million of 6% Debenture and $875,000 of 8.75% Notes. In addition, $2.5 million of Trust Preferred Securities, $815,000 of .6% Debentures and $9.0 million of 8.75% Notes were repurchased.

Other revenue increased from a loss in 2002 of $6.0 million to a loss of $2.7 million in 2003. The 2003 period includes $1.2 million of ineffective hedging losses and a net $1.4 million of IPF expenses. The 2002 period includes $2.7 million of ineffective hedging losses, $3.1 million net IPF expenses and a $1.2 million write-down of marketable securities, offset by a $715,000 arbitration recovery.

Direct operating expense increased $4.6 million to $36.4 million due to higher workover costs and increased costs from acquisitions and new wells. On a per mcfe basis, direct operating expenses increased $0.05 per mcfe, from $0.58 in 2002 to $0.63 in 2003.

Production and ad valorem taxes increased $4.3 million, or 50% as a direct result of increased market prices combined with higher production volumes. On a per mcfe basis, production and ad valorem taxes increased from $0.16 per mcfe to $0.22 per mcfe due to higher market prices.

Exploration expense increased 21% to $13.9 million due to higher seismic purchases ($3.9 million) partially offset by lower dry hole costs ($1.7 million). Exploration expenses include exploration personnel costs of $3.3 million in 2003 versus $2.8 million in 2002.

General and administrative expense for 2003 increased 41% or $7.1 million from 2002 due primarily to a $5.5 million increase in the non-cash mark-to-market expense relating to the deferred compensation plan and $1.6 million of higher salary and related benefit costs as well as higher director fees, legal and consulting fees and insurance costs. On a per mcfe basis, excluding the mark-to-market on the deferred compensation plan, general and administrative expense increased from $0.30 per mcfe in 2002 to $0.31 per mcfe in 2003.

Interest expense for 2003 declined $1.0 million or 4%, to $22.2 million. The decrease was attributable to lower outstanding debt and interest rates during 2003, partially offset by a call premium of $2.0 million on the 8.75% Notes included in interest expense. Average debt outstanding on the Senior Credit Facility was $104.7 million and $105.3 million for 2003 and 2002, respectively and the average interest rates were 3.1% and 3.4%, respectively.

Depletion, depreciation, and amortization increased 13% to $86.5 million due to higher production, an additional $4.5 million of accretion expense related to the adoption of the new accounting principle for abandonment costs, and higher unproved property charges. On a per mcfe basis, DD&A increased from $1.40 per mcfe to $1.49 per mcfe, primarily due to the added accretion expense ($.08) and unproved property charges ($.03).

Tax expense for 2003 was an $18.5 million tax provision versus a $3.4 million tax benefit for 2002. The 2002 year included the reversal of a valuation allowance as an $11.2 million reduction to 2002 income tax expense. Year-end 2003 provides tax expense at a rate of 37%. We adopted the provisions of SFAS 143 on January 1, 2003 and recognized a $4.5 million benefit from the cumulative effect of change in accounting principle, net of $2.4 million in taxes.

The following table presents information about our operating expense for each of the years in the two-year period ended December 31, 2003.

Operating expenses per mcfe	2003	2002	Change
Direct operating expense	$ 0.63	$ 0.58	$ 0.05
Production and ad valorem tax expense	0.22	0.16	0.06
General and administrative expense (excluding non-cash mark-to-market on deferred compensation plan)	0.31	0.30	0.01
Depletion, depreciation and amortization expense	1.49	1.40	0.09

GLOSSARY

The terms defined in this glossary are used in this report.

bbl. One stock tank barrel, or 42 U.S. gallons liquid volumes, used herein in reference to crude oil or other liquid hydrocarbons.

bcf. One billion cubic feet.

bcfe. One billion cubic feet of natural gas equivalents, based on a ratio of 6 mcf for each barrel of oil or NGL, which reflects the relative energy content.

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

dry hole. A well found to be incapable of producing oil or natural gas in sufficient economic quantities.

exploratory well. A well drilled to find oil or gas in an unproved area, to find a new reservoir in an existing field or to extend a known reservoir.

gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

infill well. A well drilled between known producing wells to better exploit the reservoir.

LIBOR. London Interbank Offer Rate, the rate of interest at which banks offer to lend to one another in the wholesale money markets in the City of London. This rate is a yardstick for lenders involved in many value transactions.

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

mcf. One thousand cubic feet of gas.

mcf per day. One thousand cubic feet of gas per day.

mcfe. One thousand cubic feet of natural gas equivalents, based on a ratio of 6 mcf for each barrel of oil or NGL, which reflects relative energy content.

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

Mmbtu. One million British thermal units. A British thermal unit is the heat required to raise the temperature of one-pound of water from 58.5 to 59.5 degrees Fahrenheit.

Mmcf. One million cubic feet of gas.

Mmcfe. One million cubic feet of gas equivalents.

NGLs. Natural gas liquids.

net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells.

present value (PV). The present value, discounted at 10%, of future net cash flows from estimated proved reserves, using constant prices and costs in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions).

productive well. A well that is producing oil or gas or that is capable of production.

proved developed non-producing reserves. Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

proved developed reserves. Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

proved reserves. The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years for known reservoirs under existing economics and operating conditions.

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

recompletion. The completion for production of another formation in an existing well bore.

reserve life index. Proved reserves at a point-in-time divided by the then annual production rate.

royalty acreage. Acreage represented by a fee mineral or royalty interest which entitles the owner to receive free and clear of all production costs a specified portion of the oil and gas produced or a specified portion of the value of such production.

royalty interest. An interest in an oil and gas property entitling the owner to a share of oil and natural gas production free of costs of production.

Senior Credit Facility. $600 million revolving bank facility.

Standardized Measure. The present value, discounted at 10%, of future net cash flows from estimated proved reserves after income taxes, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the Commissions's rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

overriding royalty. A royalty interest that is carved out of the operating or working interest in a well. Its term does not necessarily extend to the economic life of the property and may be of shorter duration than the underlying working interest. The term overriding royalties in which we participant through IPF typically extend until amounts financed and a designated rate of return have been achieved. If such point in time is reached, the override interest reverts back to the working interest owner.

working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production, subject to all royalties, overriding royalties and other burdens, and to all costs of exploration, development and operations, and all risks in connection therewith.

ITEM 7A. QUANTITIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in oil and gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market-risk exposure. All of our market-risk sensitive instruments were entered into for purposes other than trading. All accounts are US dollar denominated.

Commodity Price Risk

Our major market risk is exposure to oil and gas prices. Realized prices are primarily driven by worldwide prices for oil and spot market prices for North American gas production. Oil and gas prices have been volatile and unpredictable for many years.

We periodically enter into hedging arrangements with respect to our oil and gas production. Hedging is intended to reduce the impact of oil and gas price fluctuations. Certain of our hedges are swaps where we receive a fixed price for our production and pay market prices to the counterparty. In the second quarter of 2003, the hedging program was modified to include collars which assume a minimum floor price and a predetermined ceiling price. Realized gains and losses are generally recognized in oil and gas revenues when the associated production occurs. Starting in 2002, gains or losses on open contracts are recorded either in current period income or other comprehensive income (“OCI”). Generally, derivative losses occur when market prices increase, which are offset by gains on the underlying physical commodity transaction. Conversely, derivative gains occur when market prices decrease, which are offset by losses on the underlying commodity transaction. Ineffective gains and losses are recognized in earnings in other revenue. We do not enter into derivative instruments for trading purposes.

As of December 31, 2004, we had oil and gas swaps in place covering 19.7 billion cubic feet of gas, 0.6 million barrels of oil and 0.2 million barrels of NGLs. We also had collars covering 37.8 Bcf of gas and 2.8 million barrels of oil. These contracts expire monthly through December 2006. The fair value, represented by the estimated amount that would be realized upon immediate liquidation as of December 31, 2004, approximated a net pre-tax loss of $71.9 million.

Gains or losses realized on hedging transactions are determined monthly based upon the difference between contract price received by us for the sale of our hedged production and the hedge price, generally closing prices on the NYMEX. These gains and losses are included as increases or decreases to oil and gas revenues in the period the hedged production is sold. In 2002, there was a net pre-tax realized gain associated with the hedges of $17.8 million followed by a loss of $60.4 million in 2003. In 2004 pre-tax loss realized of $100.1 million was recorded relating to our hedges. Losses due to commodity hedge ineffectiveness are recognized in earnings in other revenues in our consolidated statement of operations. The ineffective portion of hedges recorded was a loss of $2.7 million in 2002 and $1.2 million in 2003 and a gain of $712,000 in 2004.

At December 31, 2004, the following commodity derivative contracts were outstanding:

Contract Type	Period	Volume Hedged	Average Hedge Price
Natural gas			
Swaps	2005	50,695 Mmbtu/day	$4.21
Swaps	2006	3,288 Mmbtu/day	$4.85
Collars	2005	67,175 Mmbtu/day	$5.25-$7.18
Collars	2006	36,363 Mmbtu/day	$5.03-$6.97
Crude Oil			
Swaps	2005	1,146 bbl/day	$26.84
Swaps	2006	400 bbl/day	$35.00
Collars	2005	4,415 bbl/day	$29.84-$37.05
Collars	2006	3,264 bbl/day	$31.53-$38.66
Natural gas liquids			
Swaps	2005	658 bbl/day	$19.20

In 2004, a 10% reduction in oil and gas prices, excluding amounts fixed through hedging transactions, would have reduced revenue by $41.5 million. If oil and gas futures prices at December 31, 2004 had declined by 10%, the unrealized hedging loss at that date would have decreased $33.5 million.

Interest Rate Risk

At December 31, 2004, we had $620.6 million of debt outstanding. Of this amount, $196.7 million bears interest at a fixed rate of 7.375%. Senior debt totaling $423.9 million bears interest at floating rates, excluding interest rate swaps, which averaged 3.9% on that date. At December 31, 2004, we had floating to fixed interest rate swap agreements totaling $45.0 million. These swaps consist of one agreement for $10.0 million at 1.4% which expires in June 2005 and two agreements totaling $35.0 million at 1.8% which expire in June 2006. On December 31, 2004, the 30-day LIBOR rate was 2.4%. A 1% increase in short-term interest rates on the floating-rate debt outstanding (net of amounts fixed through hedging transactions) at December 31, 2004 would cost us approximately $3.8 million in additional annual interest rates, net of swaps.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Reference is made to the Index to Financial Statements on page 53 for a list of financial statements and notes thereto and supplementary schedules. Schedules I, III, IV, V, VI, VII, VIII, IX, X, XI, XII and XIII have been omitted as not required or not applicable, or because the information required to be presented is included in the financial statements and related notes.

ITEM 9. CHANGE IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Management's Report on Disclosure Controls and Procedures. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined in 13a-15(e) of the Securities Exchange Act of 1934, or the Exchange Act). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective in timely alerting them to material information relating to us (including our consolidated subsidiaries) required to be included in this report. There were no changes in our internal control 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.

Management is responsible for establishing and maintaining effective internal control over financial reporting as defined in Rules 13a-15(f) under the Securities Exchange Act of 1934. Our internal control over financial reporting is designed to provide reasonable assurance to management and board of directors regarding the preparation and fair presentation of published financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2004. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework*. Based on our assessment, we believe that, as of December 31, 2004, our internal control over financial reporting is effective based on those criteria.

The scope of management's assessment of the effectiveness of internal control over financial reporting includes all of our businesses except for Pine Mountain, a material business acquired on December 10, 2004. Our revenues for the year ended December 31, 2004, were $320.7 million, of which Pine Mountain represented $2.9 million and our net income was $42.2 million of which Pine Mountain represented $1.4 million. Our total assets as of December 31, 2004, were $1.6 billion, of which the Pine Mountain represented $316.1 million. We plan to fully integrate Pine Mountain into our systems and internal controls in 2005. As of December 31, 2004, the integration process had not begun.

Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2004, has been audited by Ernst & Young, LLP, the independent registered public accounting firm which also audited our consolidated financial statements. Ernst & Young's attestation report on management's assessment of our internal control over financial reporting we included 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
Range Resources Corporation:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Range Resources Corporation (and subsidiaries) (the "Company") 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 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.

As indicated in the accompanying Management's Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of PMOG Holdings, Inc., (Pine Mountain), a material business acquired on December 10, 2004, which is included in the December 31, 2004 consolidated financial statements of the Company and constituted $316.1 million of the Company's $1.6 billion of total assets as of December 31, 2004 and $2.9 million of the Company's $320.7 million of revenues and $1.4 million of the Company's net income of $42.2 million for the year then ended. Management did not include Pine Mountain in its assessment due to the timing of the acquisition in late 2004. Management plans in 2005 to fully integrate Pine Mountain into the Company's systems and internal controls. As of December 31, 2004, the integration process has not begun. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of Pine Mountain.

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 operations, stockholders' equity, comprehensive income (loss) and cash flows for each of the two years in the period ended December 31, 2004 of the Company and our report dated February 28, 2005 expressed an unqualified opinion thereon.

Fort Worth, Texas
February 28, 2005

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE COMPANY

The officers and directors are listed below with a description of their experience and certain other information. Each director was elected for a one-year term at the 2004 annual stockholders' meeting. Officers are appointed by our board of directors.

	Age	Office Held Since	Position
Robert E. Aikman	73	1990	Director
Charles L. Blackburn	77	2003	Director, Chairman of the Board
Anthony V. Dub	55	1995	Director
V. Richard Eales	68	2001	Director
Allen Finkelson	58	1994	Director
Jonathan S. Linker	56	2002	Director
John H. Pinkerton	50	1990	Director, President, Chief Executive Officer
Jeffrey L. Ventura	47	2003	Executive Vice President – Chief Operating Officer
Steven L. Grose	56	2005	Senior Vice President – Appalachia
Roger S. Manny	47	2003	Senior Vice President and Chief Financial Officer
Herbert A. Newhouse	60	1998	Senior Vice President – Gulf Coast
Chad L. Stephens	49	1990	Senior Vice President – Corporate Development
Rodney L. Waller	55	1999	Senior Vice President and Corporate Secretary

Robert E. Aikman became a director in 1990. Mr. Aikman has more than 50 years experience in oil and gas exploration and production throughout the United States and Canada. From 1984 to 1994, he was Chairman of the Board of Energy Resources Corporation. From 1979 through 1984, he was the President and principal shareholder of Aikman Petroleum, Inc. From 1971 to 1977, he was President of Dorchester Exploration Inc. and from 1971 to 1980, he was a director and a member of the Executive Committee of Dorchester Gas Corporation. Since 1998, Mr. Aikman has been Chairman of WhamTech, Inc, an information technology company, and from 1988 to 2004 he was President of The Hawthorne Company, an entity which organizes joint ventures and provides advisory services for the acquisition of oil and gas properties and the restructuring, reorganization and/or sale of oil and gas companies. In addition, Mr. Aikman is a director of the Panhandle Producers and Royalty Owners Association and a member of the Independent Petroleum Association of America and American Association of Petroleum Landmen. Mr. Aikman received a Bachelor of Arts/Sciences from the University of Oklahoma.

Charles L. Blackburn was elected as a director in April 2003 and appointed as the non-executive Chairman of the Board. Mr. Blackburn has more than 40 years experience in oil and gas exploration and production serving in several executive and board positions. Previously, he served as Chairman and Chief Executive Officer of Maxus Energy Corporation from 1987 until that company's sale to YPF Socieded Anonima in 1995. Maxus was the oil and gas producer which remained after Diamond Shamrock Corporation's spin-off of its refining and marketing operations. Mr. Blackburn joined Diamond Shamrock in 1986 as President of their exploration and production subsidiary. From 1952 through 1986, Mr. Blackburn was with Shell Oil Company, serving as Director and Executive Vice President for exploration and production for the final ten years of that period. Mr. Blackburn has previously served on the Boards of Anderson Clayton and Co. (1978-1986), King Ranch Corp. (1987-1988), Penrod Drilling Co. (1988-1991), Landmark Graphics Corp. (1992-1996) and Lone Star Technologies, Inc. (1991-2001). Currently, Mr. Blackburn also serves as an advisory director to the oil and gas loan committee of Guaranty Bank. Mr. Blackburn received his Bachelor of Science degree in Engineering Physics from the University of Oklahoma in 1952.

Anthony V. Dub became a director in 1995. Mr. Dub is Chairman of Indigo Capital, LLC, a financial advisory firm based in New York. Prior to forming Indigo Capital in 1997, he served as an officer of Credit Suisse First Boston ("CSFB"). Mr. Dub joined CSFB in 1971 and was named a Managing Director in 1981. Mr. Dub led a number of departments during his 27 year career at CSFB including the Investment Banking Department. Mr. Dub is also Vice Chairman and a director of Capital IQ, Inc. ("CIQ"), the leader in helping organizations capitalize on synergistic integration of market intelligence, institutional knowledge and relationships. CIQ provides solutions to investment banks, investment managers, private equity funds, corporations and professional service providers. Mr. Dub received a Bachelor of Arts, *magna cum laude*, from Princeton University.

V. Richard Eales became a director in 2001. Mr. Eales has over 35 years of experience in the energy, high technology and financial industries. He is currently retired, having been a financial consultant serving energy and information technology businesses from 1999 through 2002. Mr. Eales was employed by Union Pacific Resources Group Inc. from 1991 to 1999 serving as Executive Vice President from 1995 through 1999. Prior to 1991, Mr. Eales served in various financial capacities with Butcher & Singer and Janney Montgomery Scott, investment banking firms, as CFO of Novell, Inc., a technology company, and in the treasury department of Mobil Oil Corporation. Mr. Eales received his Bachelor of Chemical Engineering from Cornell University and his Masters in Business Administration from Stanford University.

Allen Finkelson became a director in 1994. Mr. Finkelson has been a partner at Cravath, Swaine & Moore LLP since 1977, with the exception of the period 1983 through 1985, when he was a managing director of Lehman Brothers Kuhn Loeb Incorporated. Mr. Finkelson joined Cravath, Swaine & Moore, LLP in 1971. Mr. Finkelson earned a Bachelor of Arts from St. Lawrence University and a J.D. from Columbia University School of Law.

Jonathan S. Linker became a director in 2002. Mr. Linker previously served as a director of Range from August 1998 until October 2000. He has been active in the energy business since 1972. Mr. Linker began working with First Reserve Corporation in 1988 and was a Managing Director of the firm from 1996 until July 2001. Mr. Linker is currently an energy consultant. Mr. Linker has been President and a director of IDC Energy Corporation since 1987, a director and officer of Sunset Production Corporation since 1991 serving currently as Chairman, and Manager of Shelby Resources Inc., a small, privately-owned exploration and production company. He is a director and serves as chair of the audit committee of First Wave Marine, Inc. a private company providing shipyard and related services in the Houston-Galveston area. Mr. Linker received a Bachelor of Arts in Geology from Amherst College, a Masters in Geology from Harvard University and a MBA from Harvard University's Graduate School of Business Administration.

John H. Pinkerton, President, Chief Executive Officer and a director, became a director in 1988. He joined Range as President in 1990 and was appointed Chief Executive Officer in 1992. Previously, Mr. Pinkerton was Senior Vice President of Snyder Oil Corporation ("SOCO"). Prior to joining SOCO in 1980, Mr. Pinkerton was with Arthur Andersen. Mr. Pinkerton received his Bachelor of Arts in Business Administration from Texas Christian University and his Master of Arts in Business Administration from the University of Texas.

Jeffrey L. Ventura, Executive Vice President-Chief Operating Officer, joined Range in July 2003. Previously, Mr. Ventura served as President and Chief Operating Officer of Matador Petroleum Corporation which he joined in 1997. Prior to 1997, Mr. Ventura spent eight years at Maxus Energy Corporation where he managed various engineering, exploration and development operations and was responsible for coordination of engineering technology. Previously, Mr. Ventura was with Tenneco, where he held various engineering and operating positions. Mr. Ventura holds a Bachelor of Science degree in Petroleum and Natural Gas Engineering from Pennsylvania State University.

Steven L. Grose, Senior Vice President – Appalachia, joined Range in 1980. Previously, Mr. Grose was employed by Halliburton Services, Inc. from 1971 until 1978. Upon the formation of Great Lakes Energy Partners L.L.C. in September 1999, Mr. Grose was placed in charge of all operations of the joint venture between Range and FirstEnergy. Mr. Grose is a member of the Society of Petroleum Engineers and is a past president of The Ohio Oil and Gas Association. Mr. Grose received his Bachelor of Science degree in Petroleum Engineering from Marietta College. Mr. Grose was reappointed an officer in February 2005.

Roger S. Manny, Senior Vice President and Chief Financial Officer, joined Range in October 2003. Previously, Mr. Manny served as Executive Vice President and Chief Financial Officer of Matador Petroleum Corporation since 1998. Prior to 1998, Mr. Manny spent 18 years at Bank of America and its predecessors where he served as Senior Vice President in the energy group. Mr. Manny holds a Bachelor of Business Administration degree from the University of Houston and a Masters of Business Administration from Houston Baptist University.

Herbert A. Newhouse, Senior Vice President – Gulf Coast, joined Range in 1998. Mr. Newhouse had held the position of Senior Vice President – Gulf Coast since joining Range. Prior to joining Range, Mr. Newhouse served as Executive Vice President of Domain Energy Corporation and as a Vice President of Tenneco Ventures Corporation. Mr. Newhouse was an employee of Tenneco for over 17 years and has over 30 years of operational and managerial experience in the oil industry. Mr. Newhouse received a Bachelor of Science in Chemical Engineering from Ohio State University.

Chad L. Stephens, Senior Vice President – Corporate Development, joined Range in 1990. Prior to 2002, Mr. Stephens held the position of Senior Vice President –Southwest. Previously, Mr. Stephens was with Duer Wagner & Co., an independent oil and gas producer for approximately two years. Prior to that, Mr. Stephens was an independent oil operator in Midland, Texas for four years. From 1979 to 1984, Mr. Stephens was with Cities Service Company and HNG Oil Company. Mr. Stephens received a Bachelor of Arts in Finance and Land Management from the University of Texas.

Rodney L. Waller, Senior Vice President and Corporate Secretary, joined Range in 1999. Since joining Range, Mr. Waller has held the position of Senior Vice President and Corporate Secretary. Previously, Mr. Waller was Senior Vice President of SOCO, now part of Devon Energy Corporation. Before joining SOCO, Mr. Waller was with Arthur Andersen. Mr. Waller is a certified public accountant and petroleum land man. Mr. Waller served as a director of Range from 1988 to 1994. Mr. Waller received a Bachelor of Arts degree in Accounting from Harding University.

Code of Ethics. We have adopted a Code of Ethics that applies to our principal executive officers, principal financial officer, principal accounting officer, or persons performing similar functions. A copy is available on our website, www.rangeresources.com. We intend to disclose any amendments to or waivers of the Code of Ethics on behalf of our Chief Executive Officer, Chief Financial Officer, Controller and persons performing similar functions on our website at www.rangeresources.com, under the Corporate Governance caption, promptly following the date of such amendment or waiver.

Board of Directors Committees

The Board has established five committees to assist in the discharge of its responsibilities.

Governance and Nominating Committee. The Governance and Nominating Committee reviews background information on candidates for the Board of Directors and makes recommendations to the Board regarding such candidates. The committee is responsible for developing governance guidelines, overseeing compliance with such guidelines and reviewing the effectiveness of the Board and its committees at least annually. The members Governance and Nominating Committee are Messrs. Linker (Chairman), Finkelson and Aikman. All of the members of the governance and nominating committee have been deemed independent by the Board in accordance with NYSE regulations.

Audit Committee. The Audit Committee engages the Company's independent public accountants and reviews their professional services and the independence of such accountants. This Committee also reviews the scope of the audit coverage, internal audit function, the annual financial statements and such other matters with respect to the accounting, auditing and financial reporting practices and procedures as it may find appropriate or as have been brought to its attention. Messrs. Dub (Chairman), Eales and Linker are the members of the Audit Committee. The Board of Directors has determined that Mr. Eales is an "audit committee financial expert" as defined by the rules of the SEC. All audit committee members have been deemed independent by the Board in accordance with SEC regulations and NYSE Corporate Governance Listing Standards.

Compensation Committee. The Compensation Committee reviews and approves officers' salaries and administers the bonus, incentive compensation and stock option plans. The Committee advises and consults with management regarding benefits and significant compensation policies and practices. The Committee also considers candidates for officer positions. The members of the Compensation Committee are Messrs. Aikman (Chairman), Blackburn and Finkelson. All compensation committee members have been deemed independent by the Board in accordance with NYSE regulations.

Executive Committee. The Executive Committee reviews and authorizes actions required in the management of the business and affairs of the Company, which would otherwise be determined by the Board, when it is not practicable to convene the Board. The members of the Executive Committee are Messrs. Blackburn (Chairman), Finkelson and Pinkerton.

Dividend Committee. The Dividend Committee is directed to approve payment of dividends. The members of the Dividend Committee are Messrs. Blackburn and Pinkerton.

ITEM 11. COMPENSATION OF EXECUTIVE OFFICERS AND DIRECTORS

Information with respect to executive compensation is incorporated herein by reference to our Proxy Statement for the Annual Meeting of Stockholders to be held May 18, 2005.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information with respect to security ownership of certain beneficial owners and management is incorporated herein by reference to our proxy statement for the 2005 Annual Meeting of Stockholders to be held on May 18, 2005 and is incorporated by reference into this Item 12.

EQUITY COMPENSATION PLAN INFORMATION

	Number of Securities to be issued upon exercise of outstanding options	Weighted average exercise price of outstanding options	Number of securities authorized for future issuance under equity compensation plans
Equity compensation plans approved by security holders (b)	4,582,070	$ 5.39	4,145,605

(a) Although we do not maintain a formal plan, common stock is issued to officers and key employees in lieu of cash for bonuses and company matches under our deferred compensation arrangements as elected by employees. All such issuances are approved by the Compensation Committee, which is composed of three independent directors. Issuances to Named Employees are disclosed in our proxy statements.

(b) There are no equity compensation plans that have not been approved by security holders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information with respect to audit fees is incorporated herein by reference to our proxy statement for the 2005 Annual Meeting of Stockholders and is incorporated into this Item 14 by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENTS, FINANCIAL STATEMENTS SCHEDULES AND REPORTS ON FORM 8-K

(a) Documents filed as part of the report.

1. Financial Statements

   Financial Statements filed as part of this report are included in Item 8 – Financial Statements and Supplementary data.

2. Financial Statements Schedules and Supplementary Data.

   All other schedules have been omitted since information is not present in amounts sufficient to require submission of the schedule or because the information required is included in the financial statements or notes thereto.

   3. Exhibits

The following documents are filed or incorporated by reference as exhibits to this report.

Exhibit No.	Description
2.1	Purchase and Sale Agreement dated June 1, 2004 between Range and FirstEnergy Corporation (incorporated by reference to Exhibit 2.1 to our Form 8-K/A (File No. 001-12209) as filed with the SEC on July 15, 2004)
2.2	Stock Purchase Agreement dated November 22, 2004 between Range and First Reserve Fund IX, L.P., Donald E. Vandenberg, Richard M. Brillhart, Jeremy H. Grantham, Charles Ian Laredon (incorporated by reference to Exhibit 2.1 to our Form 8-K/A (File No. 001-12209) as filed with the SEC on January 27, 2005)
2.3	Purchase and Sale Agreement dated December 13, 2003, by and between Wagner & Brown, Ltd, Canyon Energy Partners, Ltd, and Intercon Gas, Inc., as sellers and Range Production I, L.P. as purchaser. Certain of the Schedules identified in the Table of Contents of the Purchase and Sale Agreement have been omitted. Range Resources Corporation agrees to furnish supplementally to the Commission on request a copy of any omitted schedules to the Purchase and Sale Agreement (incorporated by reference to Exhibit 2.1 to our Form 8-K (File No. 001-12209) as filed with the Securities and Exchange Commission (the “SEC”) on January 5, 2004)
3.1	Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on May 5, 2004)
3.2	Amended and Restated By-laws of the Company dated December 5, 2003 (incorporated by reference to Exhibit 3.2 to our Form 10K (File No. 001-12209) as filed with the SEC on March 3, 2004)
4.1	Form of 7-3/8% Senior Subordinated Notes due 2013 (contained as an exhibit 4.2 hereto)
4.2	Indenture dated July 21, 2003 by and among Range, as issuer, the Subsidiary Guarantors (as defined herein), as guarantors, and Bank One, National Association, as trustee (incorporated by reference to Exhibit 4.4.2 to our Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
4.3	Certification of Designation of the 5.90% Cumulative Convertible Preferred Stock of Range (incorporated by reference to Exhibit 4.2 to our Form 10-Q (File No. 001-12209) as filed with the SEC on November 5, 2003)
4.4	Indenture dated December 20, 1996 by and between Lomak and Keycorp Shareholder Services, Inc., as trustee (incorporated by reference to Exhibit 4.1(a) to Lomak’s Form S-3 (File No. 333-23955) as filed with the SEC on March 25, 1997)
10.1	Form of Directors and Officers Indemnification Agreement (incorporated by reference to Exhibit 10.1 (11) to Lomak’s Post-Effective Amendment No. 2 on Form S-4 to Form S-1 (File No. 333-47544) as filed with the SEC on January 18, 1994)

Exhibit No.	Description
10.2	Application Service Provider and Outsourcing Agreement dated June 1, 2000 by and between Applied Terravision Systems, Inc. and Range (incorporated by reference to Exhibit 10.4 to our Form 10-Q (File No. 001-12209) as filed with the SEC on August 8, 2000)
10.2.1	Addendum to the certain Application Service Provider and Outstanding Agreement dated June 1, 2000 by and between Applied Terravision Systems, Inc. predecessor to CGI Information Systems & Management Systems, Inc. and Range (incorporated by reference to Exhibit 10.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
10.3	Consulting Agreement dated May 21, 2003 by and between Range and Thomas J. Edelman (incorporated by reference to Exhibit 10.2 to our Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
10.4	Second Amended and Restated Credit Agreement as of June 23, 2004 among Range and Great Lakes Energy Partners L.L.C. (as borrowers) and Bank One NA, and the institutions named (therein) as lenders, Bank One NA as Administrative Agent and Banc One Capital Market, Inc. as Sale Lead Arranger and Bookrunner (incorporated by reference to Exhibit 10.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 29, 2004)
10.5	First Amendment to the Second Amended and Restated Credit Agreement dated December 6, 2004 among Range and Great Lakes Energy Partners L.L.C.(as borrowers) and J.P.Morgan Chase Bank, N.A. (successor to merger to Bank One, N.A.), a national banking association (J.P.Morgan Chase) and the institutions named (therein) as lenders, J.P.Morgan Chase as Administrative Agent (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with SEC on December 10, 2004)
10.6	Range Resources Corporation Deferred Compensation Plan for Directors and Select Employees effective December 28, 2004 (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on January 3, 2005)
10.7	Lomak 1989 Stock Option Plan dated March 13, 1989 (incorporated by reference to Exhibit 10.1(d) to Lomak’s Form S-1 (File No. 33-31558) as filed with the SEC on October 13, 1989)
10.8	Amendment to the Lomak 1989 Stock Option Plan, as amended (incorporate by reference to Exhibit 4.1 to Lomak’s Form S-8 (File No. 333-10719) as filed with the SEC on August 23, 1996)
10.9	Amendment to the Lomak 1989 Stock Option Plan, as amended (incorporated by reference to Exhibit 4.2 to Lomak’s Form S-8 (File No. 333-44821) as filed with the SEC on January 23, 1998)
10.10	Lomak 1994 Outside Directors Stock Option Plan (incorporated by reference to Exhibit 4.2 to Lomak’s Form S-8 (File No. 333-10719) as filed with the SEC on August 23, 1996)
10.11	First Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated June 8, 1995 (incorporated by reference to Exhibit 4.6 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.12	Second Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated August 21, 1996 (incorporated by reference to Exhibit 4.7 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.13	Third Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated June 1, 1999 (incorporated by reference to Exhibit 4.8 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.14	Fourth Amendment to the Company’s 1994 Outside Directors Stock Plan dated May 24, 2000 (incorporated by reference to Exhibit 4.9 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.15	2004 Non-Employee Director Stock Option Plan dated May 19, 2004 (incorporated by reference to Exhibit 4.2 to our Form S-8 (File No. 333-116320) as filed with the SEC on June 9, 2004)
10.16	Lomak 1997 Stock Purchase Plan, as amended, dated June 19, 1997 (incorporated by reference to Exhibit 10.1(1) to Lomak’s Form 10-K (File No. 001-12209) as filed with the SEC on March 20, 1998)
10.17	First Amendment to the Lomak 1997 Stock Purchase Plan dated May 26, 1999 (incorporated by reference to Exhibit 4.2 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.18	Second Amendment to the Lomak 1997 Stock Purchase Plan dated September 28,1999 (incorporated by reference to Exhibit 4.3 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.19	Third Amendment to Range’s 1997 Stock Purchase Plan dated May 24, 2000 (incorporated by reference to Exhibit 4.4 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.20	Fourth Amendment to Range’s 1997 Stock Purchase Plan dated May 24, 2001 (incorporated by reference to Exhibit 4.7 to our Form S-8 (File No. 333-63764) as filed with the SEC on June 25, 2001)
10.21	Amended and Restated 1999 Stock Option Plan (as amended May 21, 2003) (incorporated by reference to Exhibit 4.1 to our Form S-8 (File No. 333-105895) as filed with the SEC on June 6, 2003)
10.22	Fourth Amendment to the Amended and Restated 1999 Stock Option Plan dated May 19, 2004 (incorporated by reference to Exhibit 4.1 to our Form S-8 (File No. 333-116320) as filed with the SEC on June 9, 2004)

Exhibit No.	Description
10.23	Range Resources Corporation 401(k) Plan (incorporated by reference to Exhibit 10.14 to our Form S-4 (File No. 333-108516) as filed with the SEC on September 4, 2003)
10.24	Range Resources Corporation Amended and Restated Change in Control Plan dated September 15, 1998 (incorporated by reference to Exhibit 10.15 to our Form S-4 (File No. 333-108516, as filed with the SEC on September 4, 2003)
10.25*	Form of Agreement for incentive stock awards pursuant to Amended and Restated 1999 Stock Option Plan, as amended
10.26	Form of Agreement for non-qualified awards pursuant to Amended and Restated 1999 Stock Option Plan, as amended (incorporated by reference to Exhibit 10.3 to our Form 8-K (File No. 001-12209) as filed with the SEC on February 22, 2005)
10.27	Conversion Agreement dated December 27, 2004 (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on January 3, 2005)
14.1	Amended Code of Business Conduct and Ethics, as amended (incorporated by reference to Exhibit 10.4 to our Report on Form 8-K (File No. 001-12209) as filed with the SEC on February 22, 2005)
21.1*	Subsidiaries of Registrant
23.1*	Consent of Independent Public Accountants
23.2*	Consent of Independent Public Accountants
23.3*	Consent of Independent Public Accountants
23.4*	Consent of H.J. Gruy and Associates, Inc., independent consulting engineers
23.5*	Consent of DeGoyler and MacNaughton, independent consulting engineers
23.6*	Consent of Wright and Company, independent consulting engineers
31.1*	Certification by the President and Chief Executive Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification by the President and Chief Executive Officer of Range Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification by the Chief Financial Officer of Range Pursuant to 18 U.S.C. Section 350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

*Filed herewith.

(b) Exhibits required to be filed pursuant to Item 601 of Regulation S-K are contained to Exhibits listed in response to Item 15 (a)3, and are incorporated herein by reference, except that Exhibits 32.1 and 32.2 are being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section.

(c) The required financial statements and financial schedules are filed as part of this report.

SIGNATURES

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

Dated: March 1, 2005

RANGE RESOURCES CORPORATION

By: /s/ John H. Pinkerton
John H. Pinkerton
President and Chief Executive Officer

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

/s/ Charles L. Blackburn Charles L. Blackburn	Chairman of the Board	March 1, 2005
/s/ John H. Pinkerton John H. Pinkerton	President, Chief Executive Officer and Director	March 1, 2005
/s/ Roger S. Manny Roger S. Manny	Chief Financial and Accounting Officer	March 1, 2005
/s/ Robert E. Aikman Robert E. Aikman	Director	March 1, 2005
/s/ Anthony V. Dub Anthony V. Dub	Director	March 1, 2005
/s/ V. Richard Eales V. Richard Eales	Director	March 1, 2005
/s/ Jonathan S. Linker Jonathan S. Linker	Director	March 1, 2005

RANGE RESOURCES CORPORATION

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULES

(Item 15[a], [d])

REPORT OF INDEPENDENT REGISTERED PUBLIC
ACCOUNTING FIRM

The Board of Directors and Stockholders of
Range Resources Corporation:

We have audited the accompanying consolidated balance sheets of Range Resources Corporation (and subsidiaries)(the “Company”) as of December 31, 2004 and 2003, and the related consolidated statements of operations, stockholders’ equity, comprehensive income (loss) and cash flows for each of the two years in the period ended December 31, 2004. These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2004 and 2003, and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 4 to the consolidated financial statements, in 2003 the Company adopted Statement of Financial Accounting Standards No. 143, “Accounting for Asset Retirement Obligations.”

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of 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 February 28, 2005 expressed an unqualified opinion thereon.

Ernst & Young LLP

Fort Worth, Texas
February 28, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To The Board of Directors and Stockholders
Range Resources Corporation:

We have audited the accompanying consolidated statements of operations, stockholders' equity, comprehensive income (loss) and cash flows of Range Resources Corporation for the year ended December 31, 2002. These consolidated financial statements are the responsibility of Range Resources Corporation's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We did not audit the financial statements of Great Lakes Energy Partners L.L.C., a fifty percent owned consolidated subsidiary (see Note 2) for the year ended December 31, 2002, which statements reflect total revenues constituting 27 percent in 2002 of the related consolidated totals. These statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included in Great Lakes Energy Partners L.L.C. for the year ended December 31, 2002, is based solely on the report of the other auditors.

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

In our opinion, based on our audit and the report of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the results of operations and cash flows of Range Resources Corporation for the year ended December 31, 2002, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Dallas, Texas
March 4, 2003

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To The Management Committee of
Great Lakes Energy Partners, L.L.C.

We have audited the consolidated statements of income, members' equity, accumulated other comprehensive income (loss) and comprehensive income (loss), and cash flows of Great Lakes Energy Partners, L.L.C. and subsidiaries, (A Delaware limited liability company) (the Company) for the year ended December 31, 2002 (not presented separately herein). These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated results of operations and cash flows of Great Lakes Energy Partners, L.L.C. and subsidiaries for the year ended December 31, 2002 in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Fort Worth, Texas
January 31, 2003

RANGE RESOURCES CORPORATION

CONSOLIDATED BALANCE SHEET
(In thousands)

	December 31, 2004	December 31, 2003
Assets		
Current assets		
Cash and equivalents	$ 18,382	$ 631
Accounts receivable, net of allowance for doubtful accounts of $967 and $1,042 as of December 31, 2004 and 2003, respectively	81,942	42,145
Unrealized derivative gain (Note 7)	534	116
Deferred tax asset (Note 13)	26,310	19,871
Inventory and other	9,168	3,329
	136,336	66,092
Unrealized derivative gain (Note 7)	206	250
Oil and gas properties, successful efforts method (Note 16)	2,097,026	1,362,811
Accumulated depletion	(694,667)	(639,429)
	1,402,359	723,382
Transportation and field assets (Note 2)	59,423	41,218
Accumulated depreciation and amortization	(22,141)	(18,912)
	37,282	22,306
Other Assets (Note 2)	19,223	18,061
	$ 1,595,406	$ 830,091
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$ 78,723	$ 32,105
Asset retirement obligation (Note 4)	6,822	5,814
Accrued liabilities	23,292	10,768
Accrued interest (Note 6)	7,320	3,932
Unrealized derivative loss (Note 7)	61,005	54,345
	177,162	106,964
Senior debt (Note 6)	423,900	178,200
Non-recourse debt (Note 6)	—	70,000
Subordinated notes (Note 6)	196,656	109,980
Deferred tax, net (Note 13)	117,713	10,843
Unrealized derivative loss (Note 7)	10,926	17,027
Deferred compensation liability (Note 11)	38,799	16,981
Asset retirement obligation (Note 4)	63,905	46,030
Long-term capital lease obligation	5	—
Commitments and contingencies (Note 8)		
Stockholders' equity (Notes 5, 9 and 10)		
Preferred stock, $1 par, 10,000,000 shares authorized, 5.9% cumulative convertible preferred stock, none issued and outstanding at December 31, 2004, 1,000,000 shares issued and outstanding at December 31, 2003, entitled in liquidation to $50.0 million	—	50,000
Common stock, $.01 par, 100,000,000 shares authorized, 81,219,351 and 56,409,791 issued and outstanding, respectively	812	564
Capital in excess of par value	707,869	399,662
Retained earnings (deficit)	(89,597)	(124,011)
Stock held by employee benefit trust, 1,441,751 and 1,671,386 shares, respectively, at cost (Note 11)	(8,186)	(8,441)
Deferred compensation expense	(1,257)	(856)
Accumulated other comprehensive income (loss) (Note 2)	(43,301)	(42,852)
	566,340	274,066
	$ 1,595,406	$ 830,091

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENT OF OPERATIONS
(In thousands, except per share data)

	Year Ended December 31,		
	2004	2003	2002
Revenues			
Oil and gas sales	$ 315,703	$ 226,402	$ 190,954
Transportation and gathering	2,202	3,509	3,495
Gain (loss) on retirement of securities (Note 17)	(39)	18,526	3,098
Other	2,841	(2,670)	(5,958)
	320,707	245,767	191,589
Expenses			
Direct operating	46,308	36,423	31,869
Production and ad valorem taxes	20,504	12,894	8,574
Exploration	21,219	13,946	11,525
General and administrative (Note 11)	39,810	24,377	17,240
Interest expense and dividends on trust preferred	23,119	22,165	23,153
Depletion, depreciation and amortization	102,971	86,549	76,820
	253,931	196,354	169,181
Income before income taxes and accounting change	66,776	49,413	22,408
Income tax (benefit) (Note 13)			
Current	(245)	170	(4)
Deferred	24,790	18,319	(3,354)
	24,545	18,489	(3,358)
Income before cumulative effect of change in accounting principle	42,231	30,924	25,766
Cumulative effect of change in accounting principle, net of taxes (Note 4)	—	4,491	—
Net income	42,231	35,415	25,766
Preferred dividends	(5,163)	(803)	—
Net income available to common stockholders	$ 37,068	$ 34,612	$ 25,766
Earnings per common share (Note 14):			
Net income available to common stockholders	$ 0.59	$ 0.56	$ 0.49
Cumulative effect of change in accounting principle	—	0.08	—
Net income per common share	$ 0.59	$ 0.64	$ 0.49
Earnings per common share – assuming dilution	$ 0.57	$ 0.53	$ 0.47
Cumulative effect of change in accounting principle	—	0.08	—
Net income per common share – assuming dilution	$ 0.57	$ 0.61	$ 0.47

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENT OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2004	2003	2002
Cash flow from operations			
Net income	$ 42,231	$ 35,415	$ 25,766
Adjustments to reconcile net income to net cash provided by operations:			
Deferred income tax expense (benefit)	24,790	18,319	(3,353)
Cumulative effect of change in accounting principle, net	—	(4,491)	—
Depletion, depreciation and amortization	102,971	86,549	76,820
Exploration dry hole costs	9,493	3,576	5,280
Write-down of marketable securities	—	—	1,220
Unrealized hedging (gains) losses	(1,793)	679	3,005
Allowance for bad debts	1,762	2,138	4,390
Amortization of deferred issuance costs and discount	1,071	1,207	899
Debt conversion and extinguishment expense	—	465	—
Deferred compensation adjustments	20,667	6,867	2,506
(Gain) loss on retirement of securities	34	(19,634)	(3,125)
(Gain) loss on disposal of assets and other	(3,143)	217	(161)
Changes in working capital			
Accounts receivable	(25,898)	(11,530)	(2,685)
Inventory and other	(6,080)	501	(893)
Accounts payable	34,746	2,982	3,364
Accrued liabilities and other	12,432	2,217	1,439
Net cash provided by operations	213,283	125,477	114,472
Cash flow from investing			
Additions to oil and gas properties	(170,594)	(91,985)	(92,556)
Additions to field service assets	(4,237)	(2,618)	(2,815)
Acquisitions (net of cash acquired)	(485,564)	(103,869)	(21,790)
IPF net repayments	5,938	10,308	12,215
Disposal of assets	26,122	529	996
Net cash used in investing	(628,335)	(187,635)	(103,950)
Cash flow from financing			
Borrowings on credit facilities	634,578	318,700	173,400
Repayments on credit facilities	(528,878)	(262,800)	(174,900)
Issuance of subordinated notes	98,125	98,272	—
Dividends paid – common stock	(3,219)	—	—
– preferred stock	(2,950)	(803)	—
Debt issuance costs	(3,630)	(2,183)	(985)
Issuance of common stock	250,460	2,777	1,004
Other debt repayments	(11,683)	(92,508)	(11,087)
Net cash provided by (used in) financing	432,803	61,455	(12,568)
Increase (decrease) in cash and equivalents	17,751	(703)	(2,046)
Cash and equivalents, beginning of year	631	1,334	3,380
Cash and equivalents, end of year	$ 18,382	$ 631	$ 1,334

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
(In thousands)

	Preferred stock		Common stock		Capital in excess of par value	Retained earnings (deficit)	Stock held by employee benefit trust	Deferred compensation expense	Accumulated other comprehensive income	Total
	Shares	Par Value	Shares	Par Value						
Balance December 31, 2001	**—**	**$ —**	**52,643**	**$ 526**	**$ 378,426**	**$ (183,825)**	**$ (4,890)**	**$ (139)**	**$ 45,523**	**$ 235,621**
Issuance of common	—	—	717	7	4,313	—	(1,298)	14	—	**3,036**
Conversion of securities	—	—	1,632	17	8,343	—	—	—	—	**8,360**
Other comprehensive income	—	—	—	—	—	—	—	—	(66,674)	**(66,674)**
Net income	—	—	—	—	—	25,766	—	—	—	**25,766**
Balance December 31, 2002	—	—	54,992	550	391,082	(158,059)	(6,188)	(125)	(21,151)	**206,109**
Issuance of preferred	1,000	50,000	—	—	—	—	—	—	—	**50,000**
Preferred dividends ($0.80 per share)	—	—	—	—	—	(803)	—	—	—	**(803)**
Issuance of common	—	—	1,289	13	7,211	—	(2,253)	(731)	—	**4,240**
Common dividends ($0.01 per share)	—	—	—	—	—	(564)	—	—	—	**(564)**
Conversion of securities	—	—	129	1	1,369	—	—	—	—	**1,370**
Other comprehensive income	—	—	—	—	—	—	—	—	(21,701)	**(21,701)**
Net income	—	—	—	—	—	35,415	—	—	—	**35,415**
Balance December 31, 2003	1,000	50,000	56,410	564	399,662	(124,011)	(8,441)	(856)	(42,852)	**274,066**
Preferred dividends ($5.16 per share)	—	—	—	—	—	(5,163)	—	—	—	**(5,163)**
Issuance of common	—	—	18,927	189	258,266	—	255	(401)	—	**258,309**
Common dividends ($0.04 per share)	—	—	—	—	—	(2,654)	—	—	—	**(2,654)**
Conversion of securities	(1,000)	(50,000)	5,882	59	49,941	—	—	—	—	-
Other comprehensive income	—	—	—	—	—	—	—	—	(449)	**(449)**
Net income	—	—	—	—	—	42,231	—	—	—	**42,231**
Balance December 31, 2004	**—**	**—**	**81,219**	**$ 812**	**$ 707,869**	**$ (89,597)**	**$ (8,186)**	**$ (1,257)**	**$ (43,301)**	**$ 566,340**

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Net income	$ 42,231	$ 35,415	$ 25,766
Net deferred hedge gains (losses), net of tax:			
Contract settlements reclassed to income	63,633	39,640	(11,564)
Change in unrealized deferred hedging gains (losses)	(64,477)	(61,531)	(54,296)
Defaulted hedge contracts	—	—	(672)
Change in unrealized gains (losses) on securities held by deferred compensation plan, net of taxes	395	190	(142)
Comprehensive income (loss)	$ 41,782	$ 13,714	$ (40,908)

See accompanying notes.

RANGE RESOURCES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) ORGANIZATION AND NATURE OF BUSINESS

Range Resources Corporation ("Range", "we", "us", or "our") is engaged in the exploration, development and acquisition of oil and gas properties primarily in the Southwestern, Appalachian and Gulf Coast regions of the United States. We seek to increase our reserves and production primarily through drilling and complementary acquisitions. Prior to June 23, 2004, we held our Appalachian oil and gas assets through a 50% owned joint venture, Great Lakes Energy Partners L.L.C. ("Great Lakes"). On June 23, 2004, we purchased the 50% of Great Lakes that we did not own. Range is a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange.

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Range, our wholly-owned subsidiaries and a 50% pro rata share of the income and expenses of Great Lakes through June 23, 2004. The statement of operations for the twelve months ended December 31, 2004 includes 50% of the revenues and expenses of Great Lakes up to June 23, 2004 and 100% thereafter. The December 31, 2004 balance sheet includes 100% of the assets and liabilities of Great Lakes. All significant intercompany balances and transactions have been eliminated.

Use of Estimates

The preparation of financial statements in accordance with generally accepted accounting principles in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end and the reported amounts of revenues and expenses during the year. Actual results could differ from the estimates and assumptions used. Depletion of oil and gas properties is determined using estimates of proved oil and gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluation for impairment of proved and unproved oil and gas properties are subject to numerous uncertainties including estimates of future recoverable reserves and commodity price outlook. Other estimates which may significantly impact our financial statements include Independent Producer Finance, or IPF, and deferred tax valuation allowance and fair value of derivatives.

Business Segment Information

The Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards No. 131, "Disclosure about segments of an Enterprise and related information" ("SFAS 131") establishes standards for reporting information about operating segments. Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses. Separate operational financial information is available and this information is regularly evaluated by the chief decision maker for the purpose of allocating resources and assessing performance.

Segment reporting is not applicable for us as each of our core operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in SFAS 131. All of our operations involve the exploration, development and production of natural gas and oil and all of our operations are located in the United States. We have a single company – wide management team that administers all properties as a whole rather than a discrete operating segment. We track only basic operational data by area. We do not maintain separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis. Throughout the year, we freely allocate capital resources on a project-by-project basis, across our entire asset base to maximize profitability without regard to individual areas or segments.

Revenue Recognition

We recognize revenue from the sale of products and services in the period delivered. Although receivables are concentrated in the oil industry, we do not view this as unusual credit risk. We provide for allowance for doubtful accounts for specific receivables judged unlikely to be collected based on the age of the receivable, our experience with the debtor, potential offsets to the amount owed and economic conditions. In certain instances, we require purchasers to post stand-by letters of credit. In addition to the IPF allowance for doubtful accounts, we have allowances for doubtful accounts relating to exploration and production of $967,000 and $1.2 million at December 31, 2004 and 2003, respectively.

Cash and Equivalents

Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with maturities of three months or less. The December 2004 balance sheet includes $17.3 million of cash in an escrow account. These funds are proceeds received from the sale of oil and gas properties which are held in escrow to be used to purchase similar assets. We may defer the tax due on the sale of assets if we purchase similar assets by April 2005.

Marketable Securities

Holdings of equity securities qualify as available-for-sale or trading and are recorded at fair value.

Independent Producer Finance

IPF owns dollar denominated overriding royalties in oil and gas properties. The royalties are accounted for as receivables because the investment is recovered from a percentage of revenues until a specified rate of return is received. Payments received relating to the return are recognized as income with the remaining receipts reducing receivables. In 2004, all receipts were recognized as a return of capital. The receivables are evaluated quarterly and provisions for the valuation allowance are adjusted accordingly. At December 31, 2004 and 2003, IPF receivables were $4.5 million (which is net of a $2.9 valuation allowance) and $12.6 million (which is net of a $9.6 million valuation allowance), respectively. In 2004, 2003 and 2002, IPF recorded a $1.2 million, $1.7 million and $4.2 million increases in the valuation allowance, respectively. The valuation allowance at December 31, 2004.

The following table describes the activity for the past three years included in the IPF valuation allowance:

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Balance at beginning of year	$ (9,608)	$ (12,640)	$ (12,928)
Provisions charged to IPF expenses	(2,375)	(3,334)	(5,317)
Recoveries credited to IPF expenses	1,219	1,595	1,077
Amounts written off to principal	7,864	4,771	4,528
Balance at end of year	$ (2,900)	$ (9,608)	$ (12,640)

In 2004, all IPF revenues and expenses are presented net in other revenue in our consolidated statement of operations. Other revenue for 2004 includes net IPF expenses of $1.8 million which includes a $1.2 million increase in the valuation allowance, $2,000 of interest expense and $666,000 of general and administrative expenses. Other revenues for 2003 includes net IPF expenses of $1.4 million which includes IPF revenues of $1.5 million offset by a $1.7 million increase in the valuation allowance, $207,000 of interest and $1.0 million of general and administrative expense. Other revenues for 2002 includes net IPF expense of $3.1 million which includes IPF revenues of $3.8 million offset by a $4.2 million increase in the valuation allowance, $937,000 of interest expense and $1.7 million of general and administrative expense.

Oil and Gas Properties

We follow the successful efforts method of accounting for oil and gas producing activities. Exploratory drilling costs are capitalized pending determination of whether a well is successful. Exploratory wells subsequently determined to be dry holes are charged to expense. Costs resulting in exploratory discoveries and all development costs, whether successful or not, are capitalized. Geological and geophysical costs, delay rentals and unsuccessful exploratory wells are expensed. Oil and NGLs are converted to gas equivalent basis (“mcfe”) at the rate one barrel equals 6 mcf. The depletion, depreciation and amortization (“DD&A”) rates were $1.44, $1.49 and $1.40 per mcfe in 2004, 2003 and 2002, respectively. Depletion is provided on the unit-of-production method. Unproved properties had a net book value of $14.8 million, $12.2 million and $19.0 million at December 31, 2004, 2003 and 2002, respectively. Unproved properties are reviewed quarterly for impairment and impaired if conditions indicate we will not explore the acreage prior to expiration or the carrying value is above fair value.

Our long-lived assets are reviewed for impairment quarterly for events or changes in circumstances that indicate that the carrying amount of an asset may not be recoverable. Long-lived assets are reviewed for potential impairments at the lowest levels for which there are identifiable cash flows that are largely independent of other groups of assets. The review is done by determining if the historical cost of proved properties less the applicable accumulated depreciation, depletion and amortization and abandonment is less than the estimated expected undiscounted future cash flows. The expected future cash flows are estimated based on our plans to continue to produce and develop proved reserves. Expected future cash flow from the sale of production of reserves is calculated based on estimated future prices. We estimate prices based upon market related information including published futures prices. The estimated future level of production is based on assumptions surrounding future levels of prices and costs, field decline rates, market demand and supply, and the economic and regulatory climates. When the carrying value exceeds such cash flows, an impairment loss is recognized for the difference between the estimated fair market value, (as determined by discounted future cash flows) and the carrying value of the assets. In 2004, we recognized $3.6 million of impairment on an offshore property due to damage from hurricane Ivan and related production declines. This impairment is included in the DD&A in our consolidated statement of operations.

Transportation and Field Assets

Our gas transportation and gathering systems are generally located in proximity to certain of our principal fields. Depreciation on these systems is provided on the straight-line method based on estimated useful lives of 10 to 15 years. We receive third-party income for providing certain transportation and field services which is recognized as earned. Depreciation on the associated assets is calculated on the straight-line method based on estimated useful lives ranging from five to seven years. Buildings are depreciated over 10 to 15 years. Depreciation expense was $4.7 million, $3.0 million and $3.0 million in 2004, 2003 and 2002, respectively.

Other Assets

The expenses of issuing debt are capitalized and included in other assets on our consolidated balance sheet. These costs are generally amortized over the expected life of the related securities. When a security is retired prior to maturity, related unamortized costs are expensed. At December 31, 2004, such deferred financing costs totaled $5.7 million. Other assets at December 31, 2004 include $5.7 million unamortized debt issuance costs, $9.9 million of marketable securities held in the deferred compensation plan, $506,000 of long-term deposits and $3.1 million of IPF long-term receivables.

Gas Imbalances

We use the sales method to account for gas imbalances, recognizing revenue based on cash received rather than gas produced. Gas imbalances at December 31, 2004 and December 31, 2003 was not significant. At December 31, 2004, we had recorded a net liability of $688,000 for those wells where it was determined that there was insufficient reserves to recover the imbalance situation.

Stock Options

We apply the intrinsic value-based method of accounting prescribed by Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations, in accounting for our stock options. As such, compensation expense is recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price. SFAS No. 123, “Accounting for Stock-Based Compensation” (“SFAS 123”) established accounting and disclosure requirements using a fair value-based method of accounting for stock-based employee compensation plans. As allowed by SFAS 123, we have elected to continue to apply the intrinsic value-based method of accounting described above, and we have adopted the disclosure requirements of SFAS 123, which was amended by SFAS No. 148, “Accounting for Stock-Based Compensation-Transition and Disclosures.” See also recent accounting pronouncements below.

We have adopted the disclosure-only provisions of SFAS 123. Accordingly, no compensation cost has been recognized for the stock option plans because the exercise prices of employee stock options equals the market prices of the underlying stock on the date of grant. If compensation cost had been determined based on the fair value at the grant date for awards in 2004, 2003 and 2002 consistent with the provisions of SFAS 123, our net income and earnings per share would have been reduced to the pro forma amounts indicated below:

	Year Ended December 31, 2004	2003	2002
	(in thousands, except per share data)		
Net income as reported	$ 42,231	$ 35,415	$ 25,766
Add: Total stock-based employee compensation expense included in net income, net of tax	13,020	4,326	2,149
Deduct: Total stock-based employee compensation expense determined under fair value based method, net of tax	(18,948)	(7,193)	(3,069)
Pro forma net income	$ 36,303	$ 32,548	$ 24,846
Earnings per share:			
Basic-as reported	$ 0.59	$ 0.64	$ 0.49
Basic-pro forma	0.50	0.58	0.47
Diluted-as reported	0.57	0.61	0.47
Diluted-pro forma	0.48	0.57	0.46

The fair value of each option grant on the date of grant for the disclosures is estimated by using the Black-Scholes option pricing model with the following weighted-average assumption used for 2004, 2003 and 2002, respectively: fair value of $10.89, $5.01 and $4.89 per share; expected dividend per share of $0.04, $0.00 and $0.00; expected volatility factors of 164%, 167% and 166%; risk-free interest rates of 3.5%, 3.2% and 4.9%, and an average expected life of 5 years, 5 years and 9 years.

Derivative Financial Instruments and Hedging

We use commodity-based derivatives to reduce the impact of volatile oil and gas prices. For derivatives qualifying as hedges of future cash flows, the effective portion of any changes in fair value is recognized in a component of stockholders' equity called other comprehensive income ("OCI") and then reclassified to income, within oil and gas revenues, when the underlying anticipated transaction occurs. Any ineffective portion (changes in realized prices that do not match changes in the hedge price) is recognized in income, in other revenues in our consolidated statement of operations, as it occurs. Ineffective gains or losses are recorded while the hedge contract is open and may increase or reverse until settlement of the contract. Typically, when oil and gas prices increase, OCI decreases. Of the $71.9 million unrealized pre-tax hedging loss at December 31, 2004, $61.0 million of losses will be reclassified to earnings over the next 12 months period and $10.9 million for the periods thereafter, if prices remain constant. Actual amounts that will be reclassified will vary as a result of changes in prices. We have also entered into swap agreements to reduce the risk of changing interest rates. Certain of these agreements qualified as cash flow hedges whereby changes in the fair value of the swaps were reflected as an adjustment to OCI to the extent the swaps were effective and were recognized in income as an adjustment to interest expense during the period in which the cash flows related to our interest payments were made. Due to the Great Lakes acquisition and changes to our credit facility, certain of the interest rate swaps are no longer designated as hedges and are marked-to-market each month in interest expense.

Asset Retirement Obligations

The fair values of asset retirement obligations are recognized in the period they are incurred if a reasonable estimate of fair value can be made. Asset retirement obligations primarily relate to the abandonment of oil and gas producing facilities and include costs to dismantle and relocate or dispose of production platforms, gathering systems, wells and related structures. Estimates are based on historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future and federal and state regulatory requirements. We do not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined.

Accumulated Other Capital Comprehensive Income (Loss)

We follow the provisions of SFAS 130, "Reporting Comprehensive Income" which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income includes all changes in equity during the period except those resulting from investments and distributions to owners. At December 31, 2004, we had a $70.2 million pre-tax loss in OCI relating to unrealized commodity hedges and our interest rate hedges. We also had a pre-tax gain of $580,000 relating to our marketable securities in the deferred compensation plan.

The components of accumulated other comprehensive income (loss) and related tax effects for three years ended December 31, 2004, were as follows (in thousands):

	Gross	Tax Effect	Net of Tax
Accumulated other comprehensive income 2001	$ 50,018	$ (4,495)	$ 45,523
Contracts settlements reclassified to income	(17,790)	6,226	(11,564)
Change in unrealized deferred hedging losses	(63,514)	9,218	(54,296)
Defaulted hedge contracts	(1,034)	362	(672)
Change in unrealized gains (losses) on securities held by deferred compensation plan	(219)	77	(142)
Accumulated other comprehensive loss 2002	(32,539)	11,388	(21,151)
Contracts settlements reclassified to income	60,427	(20,787)	39,640
Change in unrealized deferred hedging losses	(95,657)	34,126	(61,531)
Change in unrealized gains (losses) on securities held by deferred compensation plan	297	(107)	190
Accumulated other comprehensive loss 2003	(67,472)	24,620	(42,852)
Contracts settlement reclassified to income	100,121	(36,488)	63,633
Change in unrealized deferred hedging losses	(102,506)	38,029	(64,477)
Change in unrealized gains (losses) on securities held by deferred compensation plan	626	(231)	395

Accumulated other comprehensive loss 2004	$ (69,231)	$ 25,930	$ (43,301)

Recent Accounting Pronouncements

On December 16, 2004, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 123 (revised 2004), Share-Based Payment which is a revision of FASB Statement No. 123, Accounting for Stock-Based Compensation. Statement 123(R) supercedes APB opinion No. 25, Accounting for Stock Issued to employees, and amends FASB Statement No. 95, Statement of Cash Flows. Generally, the approach in Statement 123(R) is similar to the approach described in Statement 123. However, Statement 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their fair values. Pro forma disclosure is no longer an alternative. The provisions of this statement become effective for our third quarter 2005. Management has not determined the impact that this statement will have on our consolidated financial statements.

In December 2004, the Financial Accounting Standards Board issued a FASB Staff Position (FSP) that provides accounting guidance on how companies should account for the effects of the American Jobs Creation Act of 2004 that was signed into law on October 22, 2004. FSP FAS 109-1, “Application of FASB Statement No. 109, “Accounting for Income Taxes,” to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004,” states that the manufacturers’ deduction provided for under this legislation should be accounted for as a special deduction instead of a tax rate change. The FSP may affect how a company accounts for deferred income taxes. The FSP is effective December 31, 2004. We are currently evaluating the impact from the FSP on our results of operations and financial position and we expect to complete our evaluation during the first half of fiscal 2005.

Reclassifications

Certain reclassifications of prior years’ data have been made to conform with current year classification.

(3) ACQUISITIONS AND DISPOSITIONS

Acquisitions are accounted for as purchases, and accordingly, the results of operations are included in our statement of operations from the respective date of acquisition. Purchase prices are allocated to acquired assets and assumed liabilities based on their estimated fair value at acquisition. Acquisitions have been funded with internal cash flow, bank borrowings and the issuance of debt and equity securities. We purchased various properties for consideration of $648.2 million, $100.9 million and $21.8 million, during the years ended December 31, 2004, 2003 and 2002, respectively. These purchases included $619.0 million, $90.7 million and $15.6 million for proved oil and gas reserves, respectively; the remainder represents unproved acreage purchases. As part of the acquisitions for 2004 and 2003, we allocated $15.5 million and $4.6 million, respectively, to gas gathering facilities acquired in the transactions. See also footnote 16.

On December 10, 2004, we purchased additional Appalachia oil and gas properties through the purchase of PMOG Holdings, Inc ("Pine Mountain"), a private company for $150.6 million cash paid to the seller, $57.2 million cash paid to repay debt and $13.3 million for the retirement of oil and gas commodity hedges. The following table summarizes the preliminary allocation of the purchase price to assets acquired and liabilities assumed at the date of acquisition (in thousands):

	Pine Mountain
Purchase price:	
Cash paid (including transaction costs)	$ 222,135
Total	$ 222,135
Allocation of purchase price:	
Working capital	4,845
Oil and gas properties	296,091
Field assets and gathering system assets	1,046
Deferred income taxes, net	(79,353)
Asset retirement obligations and other	(494)
Total	$ 222,135

On June 23, 2004, we purchased the 50% of Great Lakes we did not previously own for $200.0 million paid to the seller plus the assumption of $70.0 million of Great Lakes bank debt and the retirement of $27.7 million of oil and gas commodity hedges. The debt assumed was refinanced and consolidated with our existing credit facility as of the purchase date (See further discussion in Note 6.). The following table summarizes the allocation of the purchase price to the assets acquired and liabilities assumed at the date of acquisition (in thousands):

	Great Lakes
Purchase price:	
Cash paid (including transaction costs)	$ 228,924
Total	$ 228,924
Allocation of purchase price:	
Working capital	5,062
Oil and gas properties	296,260
Field assets and gathering system assets	14,429
Other non-current assets	866
Asset retirement obligations and other	(17,693)
Long-term debt	(70,000)
Total	$ 228,924

The Great Lakes and Pine Mountain acquisitions will involve many post-closing integration tasks. Among these are combining information systems and finance/accounting functions. The integration will require expenditures for information technology hardware and software, consultants, and employee costs. Due to the timing of these acquisitions, there has not been sufficient time to completely determine the scope of all integration related activities and quantify the potential cost of implementing the integration and we are continuing with the analysis. Because these issues are unresolved, additional liabilities and expense may occur from the acquisition in future periods.

The following unaudited pro forma data includes the results of operations of the above acquisitions as if they had been consummated at the beginning of 2003. The pro forma data is based on historical information and does not necessarily reflect the actual results that would have occurred nor is it necessarily indicative of future results of operations (in thousands).

	2004	2003
Revenues	$ 377,565	$ 325,977
Income before income taxes	84,645	69,971
Net income	53,489	43,883
Earnings per common share:		
- Basic	$ 0.66	$ 0.60
- Diluted	$ 0.63	$ 0.59

In April 2004, we purchased a privately held company owning producing oil and gas properties in the Permian Basin for $23.1 million. We recorded $21.9 million to oil and gas properties, $1.2 million of working capital and $213,000 of additional asset retirement obligations. No pro forma information has been provided as the acquisition was not considered significant.

In December 2003, we purchased producing oil and gas properties covering 32,000 net acres of leases which are adjacent to our Conger Field properties in West Texas. The purchase price was $87.9 million and we recorded $81.0 million to oil and gas properties, $4.6 million to transportation and field assets and facilities, $207,000 to inventory and $2.1 million of asset retirement obligations. No pro forma information has been provided as the acquisition was not considered significant.

During 2004, we sold non-strategic properties for proceeds of $25.9 million and recognized a gain of $5.0 million. Of these proceeds, $18.2 million received from the sale of certain West Texas properties was deposited into an escrow account under our control to be used for future purchases of similar assets. Proceeds from the disposal of miscellaneous properties depreciated on a group basis are credited to net book value with no immediate effect on income. However, gain or loss is recognized from the sale of less than an entire amortization base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base.

(4) ASSET RETIREMENT OBLIGATION

Effective January 1, 2003, we adopted Statement of Financial Accounting Standards No. 143 “Asset Retirement Obligations” (“SFAS 143”) which requires the recognition of an estimated liability for the plugging and abandonment of our oil and gas wells and associated pipelines and equipment. Previously, we had recognized a plugging and abandonment obligation primarily for our offshore properties. This liability was shown netted against oil and gas properties on the balance sheet. Under SFAS 143, we now recognize an asset retirement obligation in the period in which the liability is incurred, if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. SFAS 143 requires us to consider estimated salvage value in the calculation of DD&A. Consistent with industry practice, historically we had assumed the cost of plugging and abandonment on our onshore properties would be offset by salvage value received. The adoption of SFAS 143 resulted in (i) an increase of total liabilities because retirement obligations are required to be recognized, (ii) in increase in the recognized cost of assets because the retirement costs are added to the carrying amount of the long-lived asset, and (iii) an increase in DD&A expense, because of the accretion of the retirement obligation and increased basis. The majority of the asset retirement obligations recorded relate to the plugging and abandonment of oil and gas wells.

The estimated liability is based on historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future, and federal and state regulatory requirements. Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs, changes in the risk-free interest rate or remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. At the time of abandonment, we may be required to recognize a gain or loss on abandonment based on actual costs incurred.

The adoption of SFAS 143 as of January 1, 2003 resulted in a cumulative effect gain of $4.5 million (net of income taxes of $2.4 million) or $0.08 per share which is included in income in the twelve months ended December 31, 2003. The adoption resulted in a January 1, 2003 cumulative effect adjustment to record (i) a $37.3 million increase in the carrying values of proved properties, (ii) a $21.0 million decrease in accumulated depletion, (iii) a $2.3 million increase in current plugging and abandonment liabilities, (iv) a $49.1 million increase in non-current plugging and abandonment liabilities, and (v) a $2.4 million decrease in deferred tax assets.

The pro forma effects of the application of SFAS 143, as if the statement had been adopted after-tax on January 1, 2002 (rather than January 1, 2003), including an associated pro forma asset retirement obligation on that date of $48.3 million, are presented below (in thousands, except per share data):

	Pro Forma		
	2004	2003	2002
Net income	$ 42,231	$ 35,415	$ 24,535
Earnings per share - basic	$ 0.59	$ 0.64	$ 0.46
- diluted	$ 0.57	$ 0.61	$ 0.45

A reconciliation of our liability for plugging and abandonment costs for the years ended December 31, 2004 and 2003 is as follows (in thousands):

	2004	2003
Asset retirement obligation - beginning of period	$ 51,844	$ —
Cumulative effect adjustment	—	51,390
Liabilities incurred	20,237	4,598
Liabilities settled	(7,175)	(2,165)
Accretion expense	4,539	4,517
Change in estimate	1,282	(6,496)
Total	70,727	51,844
Less current portion	(6,822)	(5,814)
Asset retirement obligation – end of period	$ 63,905	$ 46,030

(5) SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31,		
	2004	2003 (in thousands)	2002
Cash used in (provided by) operating activities included:			
Income taxes paid to (refunded by) taxing authorities	$ 150	$ 110	$ (96)
Interest paid	19,216	21,579	23,277
Non-cash investing and financing activities: [a]			
Common stock issued:			
Under benefit plans	$ 2,122	$ 3,672	$ 3,092
Exchanged for fixed income securities	—	1,370	8,359
Preferred stock issued	—	50,000	—
Preferred stock converted to common stock	(50,000)	—	—
Asset retirement costs capitalized, excluding acquisitions	3,994	4,597	—

[a] For information regarding purchase price allocations of businesses acquired, see Note 3.

(6) INDEBTEDNESS

We had the following debt outstanding as of the dates shown (interest rates, excluding the impact of interest rate swaps, at December 31, 2004 are shown parenthetically) (in thousands):

	December 31, 2004	December 31, 2003
Senior debt:		
Senior Credit Facility (3.9%)	$ 423,900	$ 178,200
Non-recourse debt:		
Great Lakes Credit Facility	—	70,000
Subordinated debt:		
7.375% Senior Subordinated Notes due 2013, net of $3.3 million and $1.7 million discount, respectively	196,656	98,331
6% Convertible Subordinated Debentures due 2007	—	11,649
Total debt	$ 620,556	$ 358,180

In 2004 and 2003, we paid $178,000 and $2.0 million of call premiums in connection with the redemption of the 6% Debentures and the 8.75% Notes, respectively. No interest was capitalized during 2004, 2003, and 2002.

Senior Credit Facility

In June 2004, we entered into an amended and restated $600.0 million revolving bank facility (the “Senior Credit Facility”) which is secured by substantially all of our assets. The Senior Credit Facility provides for a borrowing base subject to redeterminations semi-annually each April and October and pursuant to certain unscheduled redeterminations. Effective December 6, 2004, the borrowing base was increased from $500.0 million to $575.0 million. As of December 31, 2004, the outstanding balance under the Senior Credit Facility was $423.9 million and there was $151.1 million of borrowing capacity available. The loan matures on January 1, 2008. Borrowing under the Senior Credit Facility can either be base rate loans or LIBOR loans. On all base rate loans, the rate per annum is equal to the lesser of (i) the maximum rate (the “weekly ceiling” as defined in Section 303 of the Texas Finance Code or other applicable laws if greater) (the “Maximum Rate”) or, (ii) the sum of (A) the higher of (1) the prime rate for such date, or (2) the sum of the federal funds effective rate for such date plus one-half of one percent (0.50%) per annum, plus a base rate margin of between 0.0% to 0.625% per annum depending on the total outstanding under the Senior Credit Facility relative to the borrowing base under the Senior Credit Facility. On all LIBOR loans, we pay a varying rate per annum equal to the lesser of (i) the Maximum Rate, or (ii) the sum of the quotient of (A) the LIBOR base rate, divided by (B) one minus the reserve requirement applicable to such interest period, plus a LIBOR margin of between 1.25% and 1.875% per annum depending on the total outstanding under the Senior Credit Facility relative to the borrowing base under the Senior Credit Facility. We may elect, from time to time, to convert all or any part of its LIBOR loans to base rate loans or to convert all or any of the base rate loans to LIBOR loans. The weighted average interest rate (including applicable margin), was 3.3% and 3.1% for the years ended December 31, 2004 and 2003, respectively. A commitment fee is paid on the undrawn balance based on an annual rate of 0.25% to 0.50%. At December, 31, 2004, the commitment fee was 0.375% and the interest rate margin was 1.5%. At February 26, 2004, the interest rate (including applicable margin) was 4.4%.

Great Lakes Credit Facility

Prior to June 23, 2004, we consolidated our proportionate share of borrowing on the Great Lakes $275.0 million bank facility (the “Great Lakes Credit Facility”). Simultaneously with the purchase of the 50% of Great Lakes we did not own, we entered into an amended and restated credit agreement (see Senior Credit Facility) with Great Lakes as a co-borrower. As a result, the outstanding balance under the Great Lakes Credit Facility was fully repaid. The average rate on the Great Lakes Credit Facility, excluding hedges, was 3.0% for the twelve months ended December 2003. After hedging (see Note 7), the rate was 5.4% for the year ended December 31, 2003.

7.375% Senior Subordinated Notes due 2013

In July 2003, we issued $100.0 million aggregate principal amount of 7.375% Senior Subordinated Notes due 2013. We pay interest on the 7.375% Notes semi-annually in arrears in January and July of each year. The 7.375% Notes mature in July 2013 and are guaranteed by certain of our subsidiaries (the "Subsidiary Guarantors"). The 7.375% Notes were issued at a discount which will be amortized over the life of the 7.375% Notes into interest expense.

We may redeem the 7.375% Notes, in whole or in part, at any time on or after July 15, 2008, at redemption prices of 103.7% of the principal amount as of July 15, 2008, and declining to 100.0% on July 15, 2011 and thereafter. Prior to July 15, 2006, we may redeem up to 35% of the original aggregate principal amount of the notes at a redemption price of 107.4% of the principal amount thereof plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings. If we experience a change of control, there may be a requirement to repurchase all or a portion of the 7.375% Notes at 101% of the principal amount thereof plus accrued and unpaid interest, if any. The 7.375% Notes and the guarantees by the Subsidiary Guarantors are general, unsecured obligations and are subordinated to our senior debt and will be subordinated to future senior debt that Range and the Subsidiary Guarantors are permitted to incur under the Senior Credit Facility and the indenture governing the 7.375% Notes.

In June 2004, we issued an additional $100.0 million of 7.375% Notes (the "Additional Notes"). The Additional Notes were issued at a $1.9 million discount which is amortized into interest expense over the remaining life of the Additional Notes.

8.75% Senior Subordinated Notes due 2007

In 1997, we sold $125.0 million in aggregate principal amount of 8.75% Senior Subordinated Notes due 2007 (the "8.75% Notes"). Interest on the 8.75% Notes was payable semi-annually in arrears in January and July of each year. On August, 20, 2003, we completed the redemption of the outstanding 8.75% Notes at 102.9% of principal amount, plus accrued interest. The aggregate redemption price, including the premium, was $70.8 million. The premium of $2.0 million is included in interest expense for the twelve months ended 2003. The redemption was financed by the issuance of the 7.375% senior subordinated notes due 2013.

6% Convertible Subordinated Debentures due 2007

In 1996, we sold $55.0 million principal amount of 6% Convertible Subordinated Debentures due 2007 (the "6% Debentures"). The outstanding 6% Debentures were redeemed on August 1, 2004 at 102.0% of principal amount plus accrued interest, including the premium, which totaled $9.1 million.

5.75% Trust Preferred Securities – manditorily redeemable securities of subsidiary

In 1997, we issued $120.0 million of the 5.75% Trust Convertible Preferred Securities ("the Trust Preferred Securities") through a newly-formed affiliated financing trust (the "Trust"). The accounts of the Trust were included in the consolidated financial statement after eliminations. Distributions of the Trust were recorded as interest expense in our consolidated statement of operations. In September 2003, we exchanged $10.2 million in cash and $50.0 million of a newly issued 5.9% cumulative convertible preferred stock (the "Convertible Preferred") for $79.5 million of the Trust Preferred Securities. In December 2003, the remainder of the Trust Preferred Securities was redeemed at a premium.

Table of Contents

Debt Covenants

The debt agreements contain covenants relating to working capital, dividends and financial ratios. We were in compliance with all covenants at December 31, 2004. Under the Senior Credit Facility, common and preferred dividends are permitted, subject to the provisions of the restricted payment basket. The Senior Credit Facility provides for a restricted payment basket of $20.0 million plus 50% of net income plus 66-2/3% of net cash proceeds from common stock issuances. Approximately $250.6 million was available under the Senior Credit Facility’s restricted payment basket on December 31, 2004. The terms of the 7.375% Notes limit restricted payments (including dividends) to the greater of $20.0 million or a formula based on earnings since the issuance of the notes. At December 31, 2004, approximately $266.9 million was available under the 7.375% Notes restricted payments basket.

Following is the principal maturity schedule for the long-term debt outstanding as of December 31, 2004 (in thousands):

Year Ended December 31:	
2005	$ —
2006	—
2007	—
2008	423,900
2009	—
2010	—
Thereafter	200,000
	$ 623,900

(7) FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Financial instruments include cash and equivalents, receivables, payables, debt and commodity and interest rate derivatives. The book value of cash and equivalents, receivables and payables is considered to be representative of fair value because of their short maturity. We mark to market all derivatives; therefore, the book value is assumed to be equal to fair value. The book value of bank borrowings is believed to approximate fair value because of their floating rate structure.

The following table sets forth the book and estimated fair values of financial instruments (in thousands):

	December 31, 2004		December 31, 2003	
	Book Value	Fair Value	Book Value	Fair Value
Assets				
Cash and equivalents	$ 18,382	$ 18,382	$ 631	$ 631
Accounts receivable	80,562	80,562	37,745	37,745
IPF receivable	4,508	4,508	12,593	12,593
Marketable securities[b]	9,866	9,866	1,765	1,765
Interest rate swaps	740	740	265	265
Commodity swaps and collars	—	—	101	101
Total	114,058	114,058	53,100	53,100
Liabilities				
Accounts payable	(78,723)	(78,723)	(32,105)	(32,105)
Commodity swaps and collars	(71,931)	(71,931)	(70,725)	(70,725)
Interest rate swaps	—	—	(647)	(647)
Long-term debt[a]	(620,556)	(633,556)	(358,180)	(358,564)
Total	(771,210)	(784,210)	(461,657)	(462,041)
	$ (657,152)	$ (670,152)	$ (408,557)	$ (408,941)

(a) Fair value based on quotes received from certain brokerage houses. Quotes for December 31, 2004 were 106.5% for the 7.375% Notes.

(b) Marketable securities held in the deferred compensation plans.

At December 31, 2004, we had open swap contracts covering 19.7 Bcf of gas at prices averaging $4.25 per mcf, 0.6 million barrels of oil at prices averaging $28.95 barrel and 0.2 million barrels of NGLs at prices averaging $19.20 per barrel. We also had collars covering 37.8 Bcf of gas at weighted average floor and cap prices of $5.03 to $7.18 per mcf and 2.8 million barrels of oil at weighted average floor and cap prices of $29.84 to $38.66 per barrel. Their fair value, represented by the estimated amount that would be realized upon termination, based on a comparison of the contract price and a reference price, generally NYMEX, approximated a net unrealized pre-tax loss of $71.9 million at December 31, 2004. These contracts expire monthly through December 2006. Transaction gains and losses are determined monthly and are included as increases or decreases to oil and gas revenues in the period the hedged production is sold. A hedging gain relating to these derivatives of $17.8 million was realized in 2002. In 2003 and 2004, losses of $60.4 million and $100.1 million were realized, respectively. These hedging positions are recorded on our consolidated balance sheet at an estimate of fair value based on a comparison of the contract price and a reference price, generally NYMEX. Other revenues in the consolidated statement of operations were increased for ineffective hedging gains of $712,000 in year ended December 31, 2004 and decreased for ineffective hedging losses of $1.2 million and $2.7 million in the years ended December 31, 2003 and 2002, respectively.

The following table sets forth the hedging volumes by year as of December 31, 2004:

Contract Type	Period	Volume Hedged	Average Hedge Price
Natural gas			
Swaps	2005	50,695 Mmbtu/day	$4.21
Swaps	2006	3,288 Mmbtu/day	$4.85
Collars	2005	67,175 Mmbtu/day	$5.25-$7.18
Collars	2006	36,363 Mmbtu/day	$5.03-$6.97
Crude Oil			
Swaps	2005	1,146 bbl/day	$26.84
Swaps	2006	400 bbl/day	$35.00
Collars	2005	4,415 bbl/day	$29.84-$37.05
Collars	2006	3,264 bbl/day	$31.53-$38.66
Natural gas liquids			
Swaps	2005	658 bbl/day	$19.20

Table of Contents

The following schedule shows the effect of the closed oil, gas and NGL hedges since January 1, 2002 and the value of open contracts at December 31, 2004 (in thousands):

Quarter Ended	Hedging Gain (Loss)
Closed Contracts	
2002	
March 31, 2002	$ 11,726
June 30, 2002	3,639
September 30, 2002	3,484
December 31, 2002	(1,059)
Subtotal	17,790
2003	
March 31, 2003	(25,890)
June 30, 2003	(15,365)
September 30, 2003	(12,257)
December 31, 2003	(6,915)
Subtotal	(60,427)
2004	
March 31, 2004	(16,896)
June 30, 2004	(23,245)
September 30, 2004	(24,382)
December 31, 2004	(35,598)
Subtotal	(100,121)
Total net realized loss	$(142,758)
Open Contracts	
2005	
March 31, 2005	$ (16,842)
June 30, 2005	(13,607)
September 30, 2005	(14,293)
December 31, 2005	(16,263)
Subtotal	(61,005)
2006	
March 31, 2006	(4,299)
June 30, 2006	(2,195)
September 30, 2006	(2,077)
December 31, 2006	(2,355)
Subtotal	(10,926)
Total net liability	$ (71,931)

We use interest rate swap agreements to manage the risk that future cash flows associated with interest payments on some amounts outstanding under the variable rate Senior Credit Facility may be adversely affected by volatility in market rates. Under swap agreements, we agree to pay an amount equal to a specified fixed rate of interest times a notional principal amount, and to receive in return, a specified variable rate of interest times the same notional principal amount. Changes in the fair value of our interest rate swaps which qualify for cash flow hedge accounting treatment, are reflected as adjustments to OCI to the extent the swaps are effective and will be recognized as an adjustment to interest expense during the period in which the cash flows related to our interest payments are made. The ineffective portion of the changes in fair value of the interest rate swaps is recorded in interest expense in the period incurred. At December 31, 2004, we had interest rate swap agreements totaling $45.0 million. These swaps consist of one agreement for $10.0 million at 1.4% which expires in June 2005 and two agreements totaling $35.0 million at 1.8% which expire in June 2006.

The fair value of the swaps at December 31, 2004, was a net hedge asset of $740,000 based on current quotes. On December 31, 2004, the 30-day LIBOR rate was 2.4%. We recognized interest income of $93,000 in 2004 and additional interest expense of $1.3 million and $2.4 million due to interest swaps in 2003 and 2002, respectively.

The combined fair value of net losses on oil and gas hedges and net gains on interest rate swaps totaling $71.2 million appears as Unrealized derivative gains and Unrealized derivative losses on our consolidated balance sheet at December 31, 2004. Hedging activities are conducted with major financial or commodities trading institutions which we believe are acceptable credit risk. At times, such risk may be concentrated with certain counterparties. The credit worthiness of these counterparties is subject to continuing review.

(8) COMMITMENTS AND CONTINGENCIES

We are involved in various legal actions and claims arising in the ordinary course of business, the largest of which *Jack Freeman, el al. v. Great Lakes Energy Partners L.L.C., et al.*, a class-action suite filed in 2000 which is currently pending against Great Lakes and Range in the state court of Chautauqua County, New York. The plaintiffs are seeking to recover actual damages and expenses plus punitive damages based on allegations that the we sold gas to affiliates and gas marketers at low prices, that inappropriate post production expenses were used to reduce proceeds to the royalty owners and that improper accounting was used for the royalty owners' share of gas. Management believes these allegations are without merit and will vigorously defend our position. Range does not believe that this litigation will have a material adverse effect on our financial position or results or operations.

We lease certain office space and equipment under cancelable and non-cancelable leases, most of which expire within three years and may be renewed. Rent expense under such arrangements totaled $1.7 million, $1.6 million and $1.7 million in 2004, 2003 and 2002, respectively. We periodically enter into arrangements to purchase seismic data over several years. These commitments total $215,000 in 2005. We record exploration expense as the data is received. Future minimum rental commitments under non-cancelable leases having remaining non-cancelable lease terms in excess of one year are as follows (in thousands):

	Operating Lease Obligations	Capital Lease Obligation
2005	$ 2,745	$ 11
2006	1,680	5
2007	714	—
2008	234	—
2009 and thereafter	154	—
	$ 5,527	$ 16

(9) STOCKHOLDERS' EQUITY

We have authorized capital stock of 110 million shares which includes 100 million shares of common stock and 10 million shares of preferred stock. In September 2003, we issued 1.0 million shares of Convertible Preferred, par value $1.00 and liquidation preference $50 per share. Effective December 31, 2004, all outstanding shares of the Convertible Preferred were converted into 5.9 million shares of common stock. The following is a schedule of changes in the number of outstanding common shares since the beginning of 2003:

	Year Ended December 31, 2004	Year Ended December 31, 2003
Beginning balance	56,409,791	54,991,611
Issuances:		
Public offerings	17,940,000	—
In lieu of fees and bonuses	30,459	182,588
Stock options exercised	834,537	687,385
Stock purchase plan	—	87,500
Restricted stock grants	80,900	234,000
Deferred compensation plan	3,671	35,350
Contributed to 401(k) Plan	37,640	62,564
Exchanged for:		
5.9% Convertible Preferred	5,882,353	—
6% Debentures	—	128,793
	24,809,560	1,418,180
Ending balance	81,219,351	56,409,791

(10) STOCK OPTION AND PURCHASE PLANS

We have five stock plans, of which three are active, and a stock purchase plan. Under these plans, incentive and non-qualified options and stock purchase rights are issued to directors, officers and employees pursuant to decisions of the Compensation Committee of the Board of Directors which is made up of outside independent directors. Information with respect to the option plans is summarized below:

	Active			Inactive			
	Director's Plan	Non-Employee Plan	1999 Plan	Domain Plan	1989 Plan	Total	Average Exercise Price
Outstanding at December 31, 2001	120,000	—	1,315,113	137,484	542,700	2,115,297	$ 4.47
Granted	48,000	—	1,438,850	—	—	1,486,850	4.89
Exercised	(2,000)	—	(66,627)	(5,782)	(56,157)	(130,566)	2.45
Expired/canceled	(14,000)	—	(142,474)	—	(32,963)	(189,437)	4.95
Outstanding at December 31, 2002	152,000	—	2,544,862	131,702	453,580	3,282,144	4.46
Granted	56,000	—	1,634,400	—	—	1,690,400	5.92
Exercised	(4,000)	—	(415,266)	(59,038)	(209,581)	(687,885)	3.55
Expired/canceled	—	—	(444,699)	—	(8,825)	(453,524)	5.46
Outstanding at December 31, 2003	204,000	—	3,319,297	72,664	235,174	3,831,135	5.00
Granted	48,000	—	1,628,500	—	—	1,676,500	11.61
Exercised	(8,000)	—	(607,282)	(72,664)	(147,324)	(835,270)	5.19
Expired/canceled	(12,000)	—	(78,295)	—	—	(90,295)	7.71
Outstanding at December 31, 2004	232,000	—	4,262,220	—	87,850	4,582,070	$ 5.39

There were options exercisable of 975,026 (weighted average price of $4.46), 1,133,850 (weighted average price of $5.00) and 1,621,530 (weighted average price of $5.39) at December 31, 2002, 2003 and 2004, respectively.

In 1999, stockholders approved the stock option plan (the "1999 Plan") under which to 9.25 million options can be granted. All options issued under the 1999 Plan through May 2002 vested over 4 years and had a maximum term of 10 years, while options issued after May 2002 vest over a three year period and have a maximum term of five years. During the year ended December 31, 2004, 1.6 million options were granted under the 1999 Plan at exercise prices ranging from $10.49 to $17.64 a share. At December 31, 2004, 4.3 million options were outstanding under the 1999 Plan at exercise prices ranging from $1.94 to $17.64.

In 1994, stockholders approved the Outside Directors' Stock Option Plan (the "Directors' Plan") where up to 300,000 options can be granted. Director's options are granted upon initial election as a director and annually upon a director's re-election at the annual meeting. During the 12 months ended December 31, 2004, 48,000 options were granted under the Directors' Plan at an exercise price of $11.30. At December 31, 2004, 232,000 options were outstanding under the Directors' Plan at exercise prices of $2.81 to $11.30. No further options can be granted under this plan after December 31, 2004.

On May 19, 2004, stockholders approved the Non-Employee Director Stock Option Plan (the "Non-Employee Plan"). The maximum number of options issuable is 300,000. The term of the options will not exceed a period of ten years. At December 31, 2004, there were no options outstanding under this plan.

We maintain the 1989 Stock Option Plan (the "1989 Plan") which authorized the issuance of options on 3.0 million common shares. No options have been granted under this plan since March 1999. Options issued under the 1989 Plan vest over a three year period and expire in ten years. At December 31, 2004, 87,850 options remained outstanding under the 1989 Plan at exercise prices of $2.63 to $7.63. The last of these options will expire in 2009.

The Domain stock option plan was adopted when that company was acquired in 1998, with existing Domain options becoming exercisable into our common stock. In January 2004, all outstanding options were exercised and the plan was terminated.

In total, 4.6 million options were outstanding at December 31, 2004 at exercise prices ranging from $1.94 to $17.64 as follows:

			Active		Inactive	
Range of Exercise price	Average Exercise price	Weighted Average Remaining Life (Yrs)	Directors' Plan	1999 Plan	1989 Plan	Total
$1.94 - $4.99	$ 3.63	5.6	48,000	472,930	72,500	593,430
5.00 - 9.99	5.86	4.1	136,000	2,198,890	15,350	2,350,240
10.00 - 14.99	10.54	4.3	48,000	1,272,200	—	1,320,200
15.00 – 17.64	16.16	4.7	—	318,200	—	318,200
		Total	232,000	4,262,220	87,850	4,582,070

During 2003, we issued 234,000 restricted shares of common stock as compensation to directors, officers and key employees at an average price of $6.40. The restricted share awards included 136,000 that were granted to directors (which vested immediately) and 98,000 to officers and employees with vesting over a three year period. In 2004, we issued 80,900 shares of restricted stock grants as compensation to directors, officers and employees (at an average price of $11.90). The restricted grants included 24,000 issued to directors (fully vested) and 56,900 to officers and key employees with vesting over a three year period. In accordance with APB opinion No. 29, we recognize unearned compensation in connection with the grant of restricted shares equal to the fair value of our common stock on date of grant. As the restricted shares vest, we reduce unearned compensation and recognize compensation expense. We recorded compensation expense of $567,000 and $753,000 in the twelve months ended December 31, 2004 and 2003, respectively, for restricted stock grants.

In 1997, stockholders approved a stock purchase plan (the "Stock Purchase Plan") which authorized the sale of 900,000 shares of common stock to officers, directors, key employees and consultants. In 2001, stockholders approved an increase in the number of shares authorized under the Stock Purchase Plan to 1.75 million. Under the Stock Purchase Plan, the right to purchase shares at prices ranging from 50% to 85% of market value may be granted. To date, all purchase rights have been granted at 75% of market. Due to the discount from market value, we recorded additional compensation expense of $122,000 and $227,800 during 2003 and 2002, respectively. Through December 31, 2004, 1,377,319 shares have been sold under the Stock Purchase Plan. During 2004, no purchase rights were granted and therefore at December 31, 2004, there were no rights outstanding to purchase shares.

(11) DEFERRED COMPENSATION

In 1996, the Board of Directors adopted a deferred compensation plan (the "Plan"). The Plan gives directors, certain officers and key employees the ability to defer all or a portion of their salaries and bonuses and invests in our common stock or makes other investments at the employee's discretion. Great Lakes also has a deferred compensation plan that allows certain employees to defer all or a portion of their salaries and bonuses and invest such amounts in certain investments at the employee discretion. The assets of the Plans are held in rabbi trusts (the "Rabbi Trust") and are therefore available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Our stock held in the Rabbi Trust is treated in a manner similar to treasury stock with an offsetting amount reflected as a deferred compensation liability and the carrying value of the deferred compensation is adjusted to fair value each reporting period by a charge or credit to operations in the general and administrative expense category on our consolidated statement of operations. The assets of the Rabbi Trust, other than our common stock, is invested in marketable securities and reported at market value in other assets on our consolidated balance sheet. The deferred compensation liability on our consolidated balance sheet reflects the market value of the securities held in the Rabbi Trust. The cost of common stock held in the Rabbi Trust is shown as a reduction to stockholder's equity. Changes in the market value of the marketable securities are reflected in OCI, while changes in the market value of our common stock held in the Rabbi Trust is charged or credited to general and administrative expense each quarter. We recorded mark-to-market expenses related to deferred compensation of $19.2 million in 2004, $6.6 million in 2003 and $1.1 million in 2002. Since we actually issue the common shares to the Rabbi Trust, we do not incur additional cash expense other than the original fair market value of the stock when issued.

(12) BENEFIT PLAN

We maintain a 401(k) Plan for our employees. The Plan permits employees to contribute up to 50% of their salary (subject to Internal Revenue Service limitations) on a pretax basis. Historically, we have made discretionary contributions of our common stock to the 401(k) Plan annually. All Company contributions become fully vested after the individual employee has three years of service with us. Great Lakes also maintained a 401(k) plan for its employees which was merged into our plan effective January 1, 2005. In 2004, 2003 and 2002, we contributed $1.2 million, $912,000 and $877,000, at then market values, respectively, of common stock to the 401(k) Plan. We do not require that employees hold the contributed stock in their account. Employees have a variety of investment options in the 401(k) Plan. Employees may, at anytime, diversify out of our stock based on their personal investment strategy.

(13) INCOME TAXES

Our federal income tax expense (benefit) for the years ended December 31, 2004, 2003 and 2002, was $24.5 million, $18.5 million and ($3.4 million), respectively. In addition, $2.4 million of tax expense was recognized as part of the cumulative effect of change in accounting principle at December 31, 2003. A reconciliation between the statutory federal income tax rate and our effective income tax rate is as follows:

	Year Ended December 31,		
	2004	2003 (in thousands)	2002
Federal statutory tax rate	35%	35%	35%
Gain on retirement of securities	—	—	6
Permanent differences	—	—	(1)
Valuation allowance	—	—	(63)
State	2	2	1
Other	—	—	4
Consolidated effective tax rate	37%	37%	(18%)
Income taxes paid (refunded)	$ 150	$ 110	($96)

Income tax provision (benefit) attributable to income before cumulative effect of change in accounting principle consists of the following:

	Year Ended December 31, 2004	2003 (in thousands)	2002
Current:			
U.S. federal	$ (192)	$ 191	$ (95)
U.S. state and local	(53)	(21)	91
	(245)	$ 170	$ (4)
Deferred:			
U.S. federal	23,450	$ 17,329	$ (3,227)
U.S. state and local	1,340	990	(127)
	$ 24,790	$ 18,319	$ (3,354)

Significant components of deferred tax liabilities and assets are as follows:

	December 31, 2004	2003
	(in thousands)	
Deferred tax assets		
Net operating loss carryover	$ 88,033	$ 69,855
Allowance for doubtful accounts	1,303	3,941
Net unrealized loss in OCI	25,930	24,620
AMT credits and other	21,916	4,813
Total deferred tax assets	137,182	103,229
Deferred tax liabilities		
Depreciation and depletion	(225,142)	(90,651)
Valuation allowance	(3,443)	(3,550)
Net deferred tax (liability) asset	$ (91,403)	$ 9,028

At December 31, 2004, deferred tax liabilities exceeded deferred tax assets by $91.4 million, with $26.0 million of deferred tax assets related to net deferred hedging losses included in OCI. A portion of our deferred tax assets relate to items which are capital assets, which upon disposition will result in capital losses. Due to the unlikely ability of us to utilize the capital loss, a valuation allowance was recognized in the amount of $3.4 million.

At December 31, 2004, we had regular net operating loss (“NOL”) carryovers of $237.2 million and alternative minimum tax (“AMT”) NOL carryovers of $205.9 million that expire between 2012 and 2023. Regular NOLs generally offset taxable income and to such extent, no income tax payments are required. We have $26.9 million of NOLs generated in years prior to 1998 which are subject to yearly limitations due to IRC Section 382. We do not believe the application of the Section 382 limitation hinders our ability to utilize such NOLs and therefore, no valuation allowance has been provided. At December 31, 2004, we have AMT credit carryovers of $1.8 million that are not subject to limitation or expiration.

(14) EARNINGS PER COMMON SHARE

The following table sets forth the computation of basic and diluted earnings per common share (in thousands, except per share amounts):

	Year Ended December 31,		
	2004	2003	2002
Numerator:			
Income before cumulative effect of change in accounting principle	$ 42,231	$ 30,924	$ 25,766
Preferred stock dividends	(5,163)	(803)	—
Numerator for basic earnings per share before cumulative effect of change in accounting principle	37,068	30,121	25,766
Cumulative effect of accounting change	—	4,491	—
Numerator for basic earnings per share	$ 37,068	$ 34,612	$ 25,766
Numerator for diluted earnings per share before cumulative effect of change in accounting principle	$ 37,068	$ 30,924	$ 25,766
Cumulative effect of accounting change	—	4,491	—
Numerator for diluted earnings per share after assumed conversions and cumulative effect of change in accounting principle	$ 37,068	$ 35,415	$ 25,766
Denominator:			
Weighted average shares outstanding	64,033	55,796	54,283
Stock held in deferred compensation plan	(1,671)	(1,524)	(1,213)
Weighted average shares, basic	62,362	54,272	53,070
Effect of dilutive securities:			
Weighted average shares outstanding	64,033	55,796	54,283
Employee stock options and other	1,299	442	135
Common shares assumed for Convertible Preferred	—	1,612	—
Dilutive potential common shares for diluted earnings per share	65,332	57,850	54,418
Earnings per share basic and diluted:			
Before cumulative effect of accounting change			
Basic	$ 0.59	$ 0.56	$ 0.49
Diluted	$ 0.57	$ 0.53	$ 0.47
After cumulative effect of accounting change			
Basic	$ 0.59	$ 0.64	$ 0.49
Diluted	$ 0.57	$ 0.61	$ 0.47

Options to purchase 318,200, 193,350 and 418,684 shares of common stock were outstanding but not included in the computation of diluted net income per shares for the twelve months ended December 31, 2004, 2003 and 2002, respectively, because the exercise prices of the options were greater than the average market price of the common shares and would be anti-dilutive to the computations. The 5.9% Convertible Preferred Stock were antidilutive in the third quarter and the nine months ended September 30, 2004.

(15) MAJOR CUSTOMERS

We market our production on a competitive basis. Gas is sold under various types of contracts including month-to-month, and one-to-five-year contracts to short-term contracts that are cancelable within 30 days. Oil purchasers may be changed on 30 days notice. The price for oil is generally equal to a posted price set by major purchasers in the area. We sell to oil purchasers on the basis of price and service. For the twelve months ended December 31, 2004, two customers accounted for 10% or more of total oil and gas revenues. For each of the years ended December 31, 2003 and 2002, three customers accounted for 10% or more of total oil and gas revenues and the combined sales to those three customers accounted for 49% and 35% of total oil and gas revenues, respectively. We believe that the loss of any one customer would not have a material long-term adverse effect on our results.

Table of Contents

(16) OIL AND GAS ACTIVITIES

The following summarizes selected information with respect to oil and gas producing activities. Exploration costs include capitalized as well as expensed outlays:

	Year Ended December 31, 2004	2003 (in thousands)	2002
Oil and gas properties:			
Properties subject to depletion	$ 2,082,236	$ 1,350,616	$ 1,135,590
Unproved properties	14,790	12,195	18,959
Total	2,097,026	1,362,811	1,154,549
Accumulated depletion	(694,667)	(639,429)	(590,143)
Net	$ 1,402,359	$ 723,382	$ 564,406
Costs incurred:			
Acquisitions:			
Acreage purchases	$ 9,600	$ 5,580	$ 6,147
Unproved leasehold	4,043	—	—
Proved oil and gas properties	522,126	88,588	15,632
Purchase price adjustment (a)	79,352	—	—
Asset retirement obligations	17,524	2,135	—
Development	144,007	80,482	63,175
Exploration(a)(b)	31,830	22,564	23,232
Gas gathering facilities:			
Acquisitions	15,539	4,622	11
Development	4,778	2,951	2,569
Subtotal	828,889	206,922	111,306
Asset retirement obligations	3,994	4,597	—
Total	$ 832,883	$ 211,519	$ 111,306

(a)Represents gross up to account for differences in book and tax basis.

(b)Includes $21,219, $13,946 and $11,525 of exploration costs expensed in 2004, 2003 and 2002, respectively.

(17) GAIN ON RETIREMENT OF SECURITIES

In the twelve months ended December 31, 2004, we recognized a loss on sale of securities primarily related to the repurchase of $2.7 million of 6% Debentures for cash. During 2003, 129,000 shares of common stock (including shares issued for interest) were exchanged for $880,000 of 6% Debentures. A conversion expense of $465,000 was recorded on the exchange. In addition, $9.1 million of 6% Debentures, $500,000 of 8.75% Notes and $5.3 million of Trust Preferred Securities were repurchased for cash. Also in 2003, $10.2 million of cash and $50.0 million of the newly issued Convertible Preferred was exchanged for $79.5 million of Trust Preferred Securities. During 2002, 1.6 million shares of common stock were exchanged for $2.4 million of Trust Preferred Securities, $7.1 million of 6% Debentures and $875,000 of 8.75% Notes. In addition, $2.5 million of Trust Preferred Securities, $815,000 of 6% Debentures and $9.0 million of 8.75% Notes were repurchased. Since 1998, there have been 15.4 million shares of common stock exchanged for convertible debt and securities in the amount of $96.7 million. In connection with these exchanges, gains of $18.5 million and $3.1 million were recorded in 2003 and 2002, respectively, because the securities were retired at a discount.

(18) UNAUDITED SUPPLEMENTAL RESERVE INFORMATION

Our proved oil and gas reserves are located in the United States. The following schedules are presented in accordance with SFAS No. 69 (“SFAS 69”), “Disclosures about Oil and Gas Producing Activities,” to provide users with a common base for preparing estimates of future cash flows and comparing reserves among companies.

Reserves of crude oil, condensate, natural gas liquids and natural gas are estimated by our engineers and are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgmental decisions are required to estimate reserves. Reported quantities are subject to future revisions, some of which may be substantial, as additional information becomes available from reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors.

The SEC defines proved reserves as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves which can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes expected to be recovered as a result of additional investments for drilling new wells to offset productive units, recompleting existing wells, and/or installing facilities to collect and transport production.

Production quantities shown are net volumes withdrawn from reservoirs. These may differ from sales quantities due to inventory changes, and especially in the case of natural gas, volumes consumed for fuel and/or shrinkage from extraction of natural gas liquids.

SFAS 69 requires calculation of future net cash flows using a 10% annual discount factor and year-end prices, costs and statutory tax rates, except for known future changes such as contracted prices and legislated tax rates. The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future cash flows because prices, costs and governmental policies do not remain static, appropriate discount rates may vary, and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

The average realized prices used at December 31, 2004 to estimate reserve information were $40.44 per barrel for oil, $25.05 per barrel for natural gas liquids and $6.05 per mcf for gas using benchmark prices of $43.33 per barrel and $6.18 per Mmbtu. The average prices used at December 31, 2003 to estimate reserve information were $29.48 per barrel for oil, $19.93 per barrel for natural gas liquids and $6.03 per mcf for gas using benchmark prices of $32.52 per barrel and $6.19 per Mmbtu. The average realized prices used at December 31, 2002 to estimate the reserve information were $27.52 per barrel for oil, $18.72 per barrel for natural gas liquids and $4.76 per mcf for gas using benchmark prices of $31.17 per barrel and $4.75 per Mmbtu.

Table of Contents

Quantities of Proved Reserves

	Crude Oil and NGLs (Mbbls)	Natural Gas (Mmcf)	Natural Gas Equivalents (Mmcfe)
Balance, December 31, 2001	20,680	388,927	513,005
Revisions	1,707	30,014	40,253
Extensions, discoveries and additions	2,830	45,652	62,635
Purchases	40	18,283	18,526
Sales	(26)	(1,513)	(1,669)
Production	(2,279)	(41,096)	(54,773)
Balance, December 31, 2002	22,952	440,267	577,977
Revisions	445	4,625	7,294
Extensions, discoveries and additions	3,331	48,364	68,351
Purchases	8,758	37,734	90,284
Sales	(39)	(1,076)	(1,312)
Production	(2,424)	(43,510)	(58,053)
Balance, December 31, 2003	33,023	486,404	684,541
Revisions	(312)	(24,251)	(26,111)
Extensions, discoveries and additions	5,515	122,790	155,875
Purchases	7,062	421,775	464,149
Sales	(3,622)	(9,568)	(31,303)
Production	(3,500)	(50,722)	(71,726)
Balance, December 31, 2004	38,166	946,428	1,175,425
Proved developed reserves			
December 31, 2002	17,176	320,224	423,280
December 31, 2003	24,912	344,187	493,659
December 31, 2004	27,715	580,006	746,299

The “Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves” (“Standardized Measure”) is a disclosure requirement of SFAS 69. The Standardized Measure does not purport to present the fair market value of proved oil and gas reserves. This would require consideration of expected future economic and operating conditions, which are not taken into account in calculating the Standardized Measure.

Future cash inflows were estimated by applying year-end prices to the estimated future production less estimated future production costs based on year-end costs. Future net cash inflows were discounted using a 10% annual discount rate to arrive at the Standardized Measure.

Table of Contents

Standardized Measure

	Year Ended December 31, 2004	2003	2002
		(in thousands)	
Future cash inflows	$ 7,109,349	$ 3,803,479	$ 2,697,068
Future costs:			
Production	(1,472,484)	(842,052)	(677,214)
Development	(601,447)	(274,029)	(204,137)
Future net cash flows	5,035,418	2,687,398	1,815,717
Income taxes	(1,523,915)	(740,965)	(463,980)
Total undiscounted future net cash flows	3,511,503	1,946,433	1,351,737
10% discount factor	(1,762,092)	(943,452)	(852,104)
Standardized measure	$ 1,749,411	$ 1,002,981	$ 499,633

Changes in Standardized Measure

	As of December 31, 2004	2003	2002
		(in thousands)	
Standardized measure, beginning of year	$ 1,002,981	$ 499,633	$ 311,408
Net changes in prices	129,916	160,932	212,091
Revision of quantities	(59,591)	267,906	116,757
Changes in estimated future development costs	(399,562)	(100,656)	(67,872)
Accretion of discount	139,582	96,361	39,915
Changes in income taxes	(254,114)	(103,375)	(103,529)
Purchases	1,059,294	145,772	17,815
Extensions, discoveries and additions	355,742	110,358	60,232
Production	(248,891)	(177,085)	(150,511)
Development costs incurred	72,144	51,005	36,488
Sales	(71,441)	(2,117)	(1,605)
Changes in timing and other	23,351	54,247	28,444
Standardized measure, end of year	$ 1,749,411	$ 1,002,981	$ 499,633

Table of Contents

RANGE RESOURCES CORPORATION

INDEX TO EXHIBITS

(Item 15[a 3]

Exhibit No.	Description
2.1	Purchase and Sale Agreement dated June 1, 2004 between Range and FirstEnergy Corporation (incorporated by reference to Exhibit 2.1 to our Form 8-K/A (File No. 001-12209) as filed with the SEC on July 15, 2004)
2.2	Stock Purchase Agreement dated November 22, 2004 between Range and First Reserve Fund IX, L.P., Donald E. Vandenberg, Richard M. Brillhart, Jeremy H. Grantham, Charles Ian Laredon (incorporated by reference to Exhibit 2.1 to our Form 8-K/A (File No. 001-12209) as filed with the SEC on January 27, 2005)
2.3	Purchase and Sale Agreement dated December 13, 2003, by and between Wagner & Brown, Ltd, Canyon Energy Partners, Ltd, and Intercon Gas, Inc., as sellers and Range Production I, L.P. as purchaser. Certain of the Schedules identified in the Table of Contents of the Purchase and Sale Agreement have been omitted. Range Resources Corporation agrees to furnish supplementally to the Commission on request a copy of any omitted schedules to the Purchase and Sale Agreement (incorporated by reference to Exhibit 2.1 to our Form 8-K (File No. 001-12209) as filed with the Securities and Exchange Commission (the "SEC") on January 5, 2004)
3.1	Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on May 5, 2004)
3.2	Amended and Restated By-laws of the Company dated December 5, 2003 (incorporated by reference to Exhibit 3.2 to our Form 10K (File No. 001-12209) as filed with the SEC on March 3, 2004)
4.1	Form of 7-3/8% Senior Subordinated Notes due 2013 (contained as an exhibit 4.2 hereto)
4.2	Indenture dated July 21, 2003 by and among Range, as issuer, the Subsidiary Guarantors (as defined herein), as guarantors, and Bank One, National Association, as trustee (incorporated by reference to Exhibit 4.4.2 to our Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
4.3	Certification of Designation of the 5.90% Cumulative Convertible Preferred Stock of Range (incorporated by reference to Exhibit 4.2 to our Form 10-Q (File No. 001-12209) as filed with the SEC on November 5, 2003)
4.4	Indenture dated December 20, 1996 by and between Lomak and Keycorp Shareholder Services, Inc., as trustee (incorporated by reference to Exhibit 4.1(a) to Lomak's Form S-3 (File No. 333-23955) as filed with the SEC on March 25, 1997)
10.1	Form of Directors and Officers Indemnification Agreement (incorporated by reference to Exhibit 10.1 (11) to Lomak's Post-Effective Amendment No. 2 on Form S-4 to Form S-1 (File No. 333-47544) as filed with the SEC on January 18, 1994)
10.2	Application Service Provider and Outsourcing Agreement dated June 1, 2000 by and between Applied Terravision Systems, Inc. and Range (incorporated by reference to Exhibit 10.4 to our Form 10-Q (File No. 001-12209) as filed with the SEC on August 8, 2000)
10.2	Addendum to the certain Application Service Provider and Outstanding Agreement dated June 1, 2000 by and between Applied Terravision Systems, Inc. predecessor to CGI Information Systems & Management Systems, Inc. and Range (incorporated by reference to Exhibit 10.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
10.3	Consulting Agreement dated May 21, 2003 by and between Range and Thomas J. Edelman (incorporated by reference to Exhibit 10.2 to our Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)

Exhibit No.	Description
10.4	Second Amended and Restated Credit Agreement as of June 23, 2004 among Range and Great Lakes Energy Partners L.L.C. (as borrowers) and Bank One NA, and the institutions named (therein) as lenders, Bank One NA as Administrative Agent and Banc One Capital Market, Inc. as Sale Lead Arranger and Bookrunner (incorporated by reference to Exhibit 10.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 29, 2004)
10.5	First Amendment to the Second Amended and Restated Credit Agreement dated December 6, 2004 among Range and Great Lakes Energy Partners L.L.C.(as borrowers) and J.P.Morgan Chase Bank, N.A. (successor to merger to Bank One, N.A.), a national banking association (J.P.Morgan Chase) and the institutions named (therein) as lenders, J.P.Morgan Chase as Administrative Agent (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with SEC on December 10, 2004)
10.6	Range Resources Corporation Deferred Compensation Plan for Directors and Select Employees effective December 28, 2004 (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on January 3, 2005)
10.7	Lomak 1989 Stock Option Plan dated March 13, 1989 (incorporated by reference to Exhibit 10.1(d) to Lomak's Form S-1 (File No. 33-31558) as filed with the SEC on October 13, 1989)
10.8	Amendment to the Lomak 1989 Stock Option Plan, as amended (incorporate by reference to Exhibit 4.1 to Lomak's Form S-8 (File No. 333-10719) as filed with the SEC on August 23, 1996)
10.9	Amendment to the Lomak 1989 Stock Option Plan, as amended (incorporated by reference to Exhibit 4.2 to Lomak's Form S-8 (File No. 333-44821) as filed with the SEC on January 23, 1998)
10.10	Lomak 1994 Outside Directors Stock Option Plan (incorporated by reference to Exhibit 4.2 to Lomak's Form S-8 (File No. 333-10719) as filed with the SEC on August 23, 1996)
10.11	First Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated June 8, 1995 (incorporated by reference to Exhibit 4.6 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.12	Second Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated August 21, 1996 (incorporated by reference to Exhibit 4.7 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.13	Third Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated June 1, 1999 (incorporated by reference to Exhibit 4.8 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.14	Fourth Amendment to the Company's 1994 Outside Directors Stock Plan dated May 24, 2000 (incorporated by reference to Exhibit 4.9 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.15	2004 Non-Employee Director Stock Option Plan dated May 19, 2004 (incorporated by reference to Exhibit 4.2 to our Form S-8 (File No. 333-116320) as filed with the SEC on June 9, 2004)
10.16	Lomak 1997 Stock Purchase Plan, as amended, dated June 19, 1997 (incorporated by reference to Exhibit 10.1(1) to Lomak's Form 10-K (File No. 001-12209) as filed with the SEC on March 20, 1998)
10.17	First Amendment to the Lomak 1997 Stock Purchase Plan dated May 26, 1999 (incorporated by reference to Exhibit 4.2 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.18	Second Amendment to the Lomak 1997 Stock Purchase Plan dated September 28,1999 (incorporated by reference to Exhibit 4.3 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.19	Third Amendment to Range's 1997 Stock Purchase Plan dated May 24, 2000 (incorporated by reference to Exhibit 4.4 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.20	Fourth Amendment to Range's 1997 Stock Purchase Plan dated May 24, 2001 (incorporated by reference to Exhibit 4.7 to our Form S-8 (File No. 333-63764) as filed with the SEC on June 25, 2001)
10.21	Amended and Restated 1999 Stock Option Plan (as amended May 21, 2003) (incorporated by reference to Exhibit 4.1 to our Form S-8 (File No. 333-105895) as filed with the SEC on June 6, 2003)
10.22	Fourth Amendment to the Amended and Restated 1999 Stock Option Plan dated May 19, 2004 (incorporated by reference to Exhibit 4.1 to our Form S-8 (File No. 333-116320) as filed with the SEC on June 9, 2004)
10.23	Range Resources Corporation 401(k) Plan (incorporated by reference to Exhibit 10.14 to our Form S-4 (File No. 333-108516) as filed with the SEC on September 4, 2003)
10.24	Range Resources Corporation Amended and Restated Change in Control Plan dated September 15, 1998 (incorporated by reference to Exhibit 10.15 to our Form S-4 (File No. 333-108516, as filed with the SEC on September 4, 2003)
10.25*	Form of Agreement for incentive stock awards pursuant to Amended and Restated 1999 Stock Option Plan, as amended
10.26	Form of Agreement for non-qualified awards pursuant to Amended and Restated 1999 Stock Option Plan, as amended (incorporated by reference to Exhibit 10.3 to our Form 8-K (File No. 001-12209) as filed with the SEC on February 22, 2005)

Exhibit No.	Description
10.27	Conversion Agreement dated December 27, 2004 (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on January 3, 2005)
14.1	Amended Code of Business Conduct and Ethics, as amended (incorporated by reference to Exhibit 10.4 to our Report on Form 8-K (File No. 001-12209) as filed with the SEC on February 22, 2005)
21.1*	Subsidiaries of Registrant
23.1*	Consent of Independent Public Accountants
23.2*	Consent of Independent Public Accountants
23.3*	Consent of Independent Public Accountants
23.4*	Consent of H.J. Gruy and Associates, Inc., independent consulting engineers
23.5*	Consent of DeGoyler and MacNaughton, independent consulting engineers
23.6*	Consent of Wright and Company, independent consulting engineers
31.1*	Certification by the President and Chief Executive Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification by the President and Chief Executive Officer of Range Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification by the Chief Financial Officer of Range Pursuant to 18 U.S.C. Section 350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

*Filed herewith.

EXHIBIT 10.25

Number:

Notice of Grant of Stock Options and Option Agreement	**Range Resources Corporation** **ID: 34-1312571** **777 MAIN STREET** **SUITE 800** **FORT WORTH, TEXAS 76102**
	Option **Plan: 99SO** **ID:**

Effective [Date] you have been granted a Range Resources Corporation (the "Company") Incentive Stock Option to buy [Number] shares of common stock at a price of $[Price] per share.

The total option price of the shares granted is $[Total price].

Subject to the terms and provisions of Annex A hereto, the Incentive Stock Option will have a term of 10 years and the option shares will vest at 25% per year over a four year period. The shares vesting in each period will be fully vested on the date shown below.

Shares Granted	**Vesting Date**	**Expiration Date**

By your signature and the Company's signature below, you and the Company agree that the options granted hereby are granted under and governed by the terms and conditions of the 1999 Stock Incentive Plan (the "Plan"). The Plan is on file in the Company's corporate records and a copy is available upon request to the Company's Secretary.

RANGE RESOURCES CORPORATION

BY ______________________________ ______________________________

RODNEY L. WALLER
SENIOR VICE PRESIDENT

DATE

BY ______________________________ ______________________________

[Optionee]

DATE

ANNEX A

1. Defined Terms. Defined terms used in this Annex A shall have the meanings set forth in the Plan, as it may be amended from time to time, or the Option Agreement to which this Annex A is attached.

2. Vesting. The option shares subject to the Stock Option shall cease to vest, and the unvested portion of the Stock Option shall immediately terminate, in the event that the Holder shall cease to be in the employ of the Company or any Affiliate for any reason.

3. Term and Time of Exercise Prior to Change of Control.

(a) Termination of Employment other than due to Death or Disability. In the event that a Holder, prior to a Change of Control, shall cease to be in the employ of the Company or an Affiliate for any reason, other than by reason of death or disability, then the vested and unexercised portion of the Stock Option shall terminate at 5:00 p.m. Fort Worth, Texas time on the date that is 30 days after the date of such Holder's termination of employment; provided, however, that, notwithstanding the foregoing, (A) in the event the employment of the Holder is terminated prior to a Change of Control for dishonesty or other acts detrimental to the interest of the Company or any Affiliate or for any breach by the Holder of any employment contract with the Company or any Affiliate, as determined in each case by the Committee in its sole and absolute discretion, or (B) if, after the Holder's employment is terminated prior to a Change of Control, the Holder commits an act that is determined by the Committee, in its sole and absolute discretion, to be detrimental to the interests of the Company or any Affiliate, then, in the case of clause (A) or (B), the Stock Option shall automatically be null and void at the time of such determination.

(b) Termination due to Disability. In the event that a Holder, prior to a Change of Control, shall cease to be in the employ of the Company or an Affiliate by reason of disability, as determined by the Committee in its sole and absolute discretion, then the vested and unexercised portion of the Stock Option shall terminate at 5:00 p.m. Fort Worth, Texas time on the one-year anniversary date of such Holder's termination of employment.

(c) Termination due to Death. In the event that a Holder, prior to a Change of Control, dies while in the employ of the Company or an Affiliate, the vested and unexercised portion of the Stock Option shall (i) terminate at 5:00 p.m. Fort Worth, Texas time on the one-year anniversary date of such Holder's death and (ii) be exercisable only by the person or persons to whom the Holder's rights under the Stock Option shall pass by the Holder's will or the laws of descent and distribution.

(d) Maximum Term. Notwithstanding any provision of Section 3(a), 3(b), or 3(c) to the contrary, the Stock Option shall not be exercisable after the Expiration Date set forth in the Option Agreement.

EXHIBIT 21.1

RANGE RESOURCES CORPORATION

Subsidiaries of Registrant

Name	Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
Range Production Company	Delaware	100%
Range Energy Services Company	Delaware	100%
Range Holdco, Inc.	Delaware	100%
Range Energy I, Inc.	Delaware	100%
Range Gathering & Processing Company	Delaware	100%
Range Gas Company	Delaware	100%
RRC Operating Company	Ohio	100%
Range Energy Finance Corporation	Delaware	100%
Range Energy Ventures Corporation	Delaware	100%
Gulfstar Energy, Inc.	Delaware	100%
Gulfstar Seismic, Inc.	Delaware	100%
Domain Energy International Corporation (a)	British Virgin Islands	100%
Energy Assets Operating Company	Delaware	100%
RB Operating Company	Delaware	100%
PMOG Holdings, Inc.	Delaware	100%
Pine Mountain Acquisition, Inc.	Delaware	100%
Pine Mountain Oil & Gas, Inc.	Virginia	100%
Great Lakes Energy Partners, L.L.C.	Delaware	100%
Ohio Interstate Gas Transmission Company	Ohio	100%
Victory Energy Partners, L.L.C.	Texas	100%

(a) Dormant subsidiary with no assets.

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Range Resources Corporation:

We consent to the incorporation by reference in the Registration Statements on Form S-3/A (No. 333-76837 and No. 333-118417), on Form S-4, (Nos. 333-78231, 333-78231, 333-108516 and 333-117834) and on Form S-8 (Nos. 333-90760, 333-63764, 333-40380, 333-30534, 333-88657, 333-69905, 333-62439, 333-44821, 333-10719, 333-105895 and 333-116320) of Range Resources Corporation and in the related Prospectuses of our report dated February 28, 2005 with respect to the consolidated financial statements of Range Resources Corporation (and subsidiaries), management's assessment of the effectiveness of internal control over financial reporting, and the effectiveness of internal control over financial reporting of Range Resources (and subsidiaries), included in this Annual Report (Form 10-K) for the year ended December 31, 2004.

/s/ Ernst & Young LLP

Fort Worth, Texas
February 28, 2005

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Range Resources Corporation:

We consent to the incorporation by reference in the Registration Statements (No. 333-76837 and No. 333-118417) on Form S-3, (No. 333-78231 and 333-108516) on Form S-4, and (Nos. 333-90760, 333-63764, 333-40380, 333-30534, 333-88657, 333-69905, 333-62439, 333-44821, 333-10719, 333-105895 and 333-116320) on Form S-8 of Range Resources Corporation of our report relating to the consolidated statements of operations, stockholders' equity, comprehensive income (loss) and cash flows for the year ended December 31, 2002.

/s/ KPMG LLP

Dallas, Texas
March 1, 2005

EXHIBIT 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-118417), on Form S-3/A (No. 333-76837), on Form S-4/A (No. 333-108516, 333-78231 and 333-117834) and Forms S-8 (No. 333-105895, 333-90760, No. 333-63764, No. 333-40380, No. 333-30534, No. 333-88657, No. 333-69905, No. 333-62439, No. 333-44821 and No. 333-10719 and 333-116320) of Range Resources Corporation and in the related Prospectuses of our report dated January 31, 2003, included in this Annual Report (Form 10-K) of Range Resources Corporation for the year ended December 31, 2004 with respect to the consolidated financial statements of Great Lakes Energy Partners, L.L.C. for the year ended December 31, 2002.

/s/ ERNST & YOUNG LLP

Fort Worth, Texas
February 28, 2005

EXHIBIT 23.4

CONSENT OF H.J. GRUY AND ASSOCIATES, INC.

We hereby consent to the use of the name H.J. Gruy and Associates, Inc., and of references to H.J. Gruy and Associates, Inc. and to the inclusion of and references to our report dated February 14, 2005, prepared for Range Resources Corporation in the Range Resources Corporation Annual Report on Form 10-K for the year ended December 31, 2004. We are unable to verify the accuracy of the reserves and discounted present worth values contained therein because our estimate of reserves and discounted present worth have been combined with estimates of reserves and present worth prepared by other petroleum consultants.

H.J. GRUY AND ASSOCIATES, INC.

February 28, 2005
Houston, Texas

EXHIBIT 23.5

CONSENT OF DEGOLYER AND MACNAUGHTON

We hereby consent to the reference to our firm under the heading “Item 2. Properties – Proved Reserves” in the Annual Report on Form 10-K of Range Resources Corporation for the year ended December 31, 2004, to which this consent is an exhibit. We also consent to the incorporation of information contained in our “Appraisal Report as of December 31, 2004, of Certain Interests owned by Range Resources Corporation,” provided, however, that we are necessarily unable to verify the accuracy of the reserves and discounted present worth values contained therein because our estimates of reserves and discounted present worth have been combined with estimates of reserves and present worth prepared by other petroleum consultants.

DEGOLYER AND MACNAUGHTON

Dallas, Texas
February 28, 2005

EXHIBIT 23.6

CONSENT OF WRIGHT AND COMPANY

We hereby consent to the incorporation by reference of our name in the Annual Report on Form 10-K of Range Resources Corporation (the “Company”) for the fiscal year ended December 31, 2004, to which this consent is an exhibit.

WRIGHT AND COMPANY

Wright and Company, Inc.
Brentwood, Tennessee
February 28, 2005

EXHIBIT 31.1

CERTIFICATION

I, John H. Pinkerton, certify that:

1. I have reviewed this report on Form 10-K of Range Resources Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

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

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

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

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

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

Date: March 1, 2005

/s/ JOHN H. PINKERTON
John H. Pinkerton
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Roger S. Manny, certify that:

1. I have reviewed this report on Form 10-K of Range Resources Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

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

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

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

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

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

Date: March 1, 2005

/s/ ROGER S. MANNY
Roger S. Manny
Senior Vice President and Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF
PRESIDENT AND CHIEF EXECUTIVE OFFICER
OF RANGE RESOURCES CORPORATION
PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the accompanying report on Form 10-K for the period ending December 31, 2004 and filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, John H. Pinkerton, President and Chief Executive Officer of Range Resources Corporation (the “Company”), hereby certify that:

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

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

By: /s/ JOHN H. PINKERTON
John H. Pinkerton
March 1, 2005

EXHIBIT 32.2

**CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF RANGE RESOURCES CORPORATION
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying report on Form 10-K for the period ending December 31, 2004 and filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Roger S. Manny, Chief Financial Officer of Range Resources Corporation (the "Company"), hereby certify that:

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

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

By: /s/ ROGER S. MANNY
Roger S. Manny
March 1, 2005