RANGE RESOURCES CORP
Form 10-K/A
April 08, 2004

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K/A

Amendment No. 1

(Mark one)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2003

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 þ No o

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

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

Yes þ No o

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, 2003 was $342,117,000.

As of February 26, 2004, there were 56,674,425 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 2004 Annual Meeting of Stockholders are incorporated by reference in Part III of this Report.

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EXPLANATORY NOTE

Range Resources Corporation (the Company) is filing this Amendment No. 1 to our Annual Report on Form 10-K/A for the year ended December 31, 2003 as filed by the Company on March 3, 2004 to revise an inadvertent inaccuracy in footnote 19 to the consolidated financial statements concerning unaudited standardized measure and changes in standardized measure. The Company is not making any other changes to the 10-K. For convenience and ease of reference, the Company is filing this Annual Report in its entirety with the applicable changes. Unless otherwise stated, all information contained in the amendment is as of March 3, 2004, the filing date of the Annual Report of Form 10-K for the year ended December 31, 2003. This Amendment No. 1 to the Annual Report on Form 10-K/A should be read in conjunction with our subsequent filings with the SEC.

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RANGE RESOURCES CORPORATION

Annual Report on Form 10-K
Year Ended December 31, 2003

PART I

ITEM 1. BUSINESS

General

Range Resources Corporation (the Company or Range) is engaged in the exploration, development and acquisition of oil and gas properties, primarily in the Southwestern, Gulf Coast and Appalachian regions of the United States. The Company seeks to increase its reserves and production through internally generated drilling projects coupled with complementary acquisitions. The Company holds its Appalachian assets through a 50% owned joint venture, Great Lakes Energy Partners L.L.C. (Great Lakes). The Company s interest in Great Lakes assets and operations is consolidated in its financial statements. At December 31, 2003, the Company had 685 Bcfe of proved reserves, having an estimated pretax present value of $1.4 billion based on constant NYMEX prices of $32.52 per barrel and $6.19 per Mmbtu. The Company s proved reserves are 71% natural gas by volume, 72% developed and 93% operated. At year-end, the Company had a reserve life index of 11 years and owned 834,000 (376,000 net) acres of undeveloped leasehold.

History

The Company was incorporated in 1980 under the name Lomak Petroleum, Inc. by a group of investors who had been developing oil and gas properties since 1976 in the Appalachian Basin. Shortly after its incorporation in 1980, the Company completed an initial public offering and began trading on the NASDAQ. Throughout the 1980 s, the Company conducted drilling operations, primarily in the Appalachian Basin and to a lesser extent in Michigan and Texas. After several years of depressed oil and gas prices, in 1988 the Company began to focus on acquiring producing oil and gas properties. From 1988 through 1996, total assets grew from less than $10 million to nearly $300 million through a series of smaller acquisitions which expanded the Company s operations into the Southwest and Gulf Coast regions. In 1996, the Company s common stock was listed on the New York Stock Exchange. In 1997 and 1998, two large acquisitions were completed which increased total assets to over $900 million. Upon completing the second acquisition, the Company changed its name to Range Resources Corporation. The two large acquisitions were financed primarily with debt. At year-end 1998, due to its high debt and coupled with the poor performance of the two large acquisitions and falling oil and gas prices, the Company was overleveraged. In 1999, the Company initiated a series of activities to reduce debt and strengthen its financial position. These activities included reducing capital expenditures, selling non-core assets, creating the Great Lakes joint venture and exchanging common stock for outstanding debt and convertible securities. As a result, since year-end 1998, debt and convertible securities have been reduced by approximately $400 million or roughly 50%.

In addition to rebuilding its financial strength, the Company instituted efforts to implement a more balanced strategy of internally generated drillbit growth coupled with complementary acquisitions. These efforts included significantly expanding its technical staff, upgrading its management team and increasing its acreage and seismic expenditures. Currently, the Company believes it has developed a substantial inventory of drilling projects balanced between lower risk and moderate risk development and higher risk exploration. The Company s more balanced approach has resulted in much improved operating and financial results in 2002 and 2003. During this two year period, the Company increased its proved reserves 33% at an average finding and development cost of $1.11 per mcfe. The Company has announced a $126.0 million 2004 capital budget excluding acquisitions. The budget includes $109.0 million to drill 409 gross (237 net) wells and initiate 35 gross (29 net) recompletions. Also included is $15.0 million for land and seismic and $2.0 million for the expansion and enhancement of gathering systems pipelines and facilities.

Description of the Business

Strategy. From 1988 through 1999, the Company s strategy centered on the acquisition of producing oil and gas properties and the subsequent development of the acquired properties. During that period, total assets grew from less than $10 million to over $900 million. In 1999, the Company initiated a series of activities to strengthen its financial position while simultaneously re-evaluating its growth strategy. In response to its larger size and due to the increased competition for

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acquisitions, the Company decided to implement a more balanced strategy of internally generated drillbit growth coupled with complementary acquisitions. The Company expanded its technical staff, upgraded its management team and significantly increased capital expenditures for acreage and seismic. As a result, the Company s drilling inventory has evolved from an inventory of primarily lower risk, lower return projects to a larger, more balanced portfolio of lower risk development, moderate risk exploitation and higher risk exploration projects. With its larger, more balanced drilling inventory, the objective each year is to generate baseline production and reserve growth through the drilling projects that are diversified according to risk and geographically divided among its three divisions. Acquisitions of producing properties are intended to complement the Company s drilling activities and provide incremental growth in production and reserves.

The Company s more balanced growth strategy is intended to provide better returns on capital expended and more consistent operating and financial results over a multi-year period. As part of its effort to generate consistent operating and financial results, the Company seeks to maintain a reserve life of no less than 10 years. By maintaining a 10+ year reserve life, the Company believes it is reducing the reinvestment risk associated with a shorter reserve life. Also, to help insure that drilling related capital expenditures can be funded through internally generated cash flow, the Company enters into hedging arrangements to reduce the volatility of oil and gas prices, therefore increasing the predictability of its cash flow. During the period it was reducing debt and enhancing its financial position, the Company primarily used a series of swap arrangements to lock in oil and gas prices. Beginning in 2003, the Company began to use zero-premium collars to provide downside protection from falling prices while retaining a portion of the upside potential of rising prices. In the future, the Company anticipates it will use a combination of swaps and collars to reduce the volatility of oil and gas prices, increasing the predictability of its cash flow and locking in returns generated on capital expended.

At year-end 2003, the Company had 2,135 proven recompletion and development projects in inventory. Given current oil and gas prices, hedges and its development inventory, the Company believes it can achieve growth in reserves, production, cash flow and earnings over the next several years. The Company s 834,000 gross (376,000 net) acres of undeveloped leasehold and 1,255,000 gross acres (652,000 net) developed leasehold provide significant long-term exploration and development potential.

Development. Development projects include recompletions of existing wells, infill drilling and the installation of secondary recovery projects. Such projects are pursued within core areas where the Company has competitive operational and technical experience. At December 31, 2003, the Company had an inventory of 1,883 proven drilling locations and 252 proven recompletions. During 2004, the Company plans to drill 247 proven locations and recomplete 48 wells. In addition, the Company plans to drill more than 145 unproved projects. The following table summarizes 2003 development activity and changes in the inventory of proved development projects:

	Development Projects		
	Drilling Locations	**Recompletion Opportunities**	**Total**
Beginning of 2003	1,770	277	2,047
Drilled	(173)	(26)	(199)
Added	376	25	401
Deleted & other	(90)	(24)	(114)
End of 2003	1,883	252	2,135

Exploration. Onshore exploration acreage totals 448,000 gross (182,000 net) acres. The projects target deeper horizons in existing fields as well as trend areas. Offshore exploration focuses on the shallow waters of the Gulf of Mexico where the Company owns a license on 3-D seismic data covering 4.0 million contiguous acres. The Company has offshore leases covering 149,000 (42,000 net) acres on which 8 specific projects have been identified to date. The Company s strategy limits risk by judicious use of state-of-the-art exploration technology, extensive geologic and engineering project analysis and a thorough review of capital expenditures by management. At times, on certain exploratory wells, other companies pay a disproportionate share of exploration costs to earn an interest. The Company currently expects to participate in as many as 28 exploratory wells in 2004.

Acquisitions. After two years during which the Company withdrew from the market, an acquisition program was reinstated in 2002. In 2002, several small acquisitions were completed. In December 2003, the Company completed the purchase of 603 wells on 38,000 gross (32,000 net) acres of leases together with associated reserves and production equipment which are adjacent to the Company s Conger Field properties in Sterling County, Texas. The purchase price should approximate $87.1 million after normal post-closing adjustments and including $2.1 million of estimated asset retirement obligations. The Company will continue to pursue acquisitions in 2004 with a focus on purchases of properties in existing core areas.

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Development and Exploration

In 2003, the Company spent $206.9 million on oil and gas related capital expenditures, an increase of 86%, with $156.4 million expended in the Southwest, $30.4 million in Appalachia and $20.1 million in the Gulf Coast. The spending funded the drilling of 358 (200.3 net) new wells, 56 (45.3 net) recompletions, $11.5 million of acreage and seismic and $95.3 million of producing property acquisitions (See Note 16 to the Consolidated Financial Statements). Exploration and development spending brought 23.2 Bcfe of proved non-producing reserves on stream and added a net 68.3 Bcfe of new reserves. Producing property acquisitions added 90.3 Bcfe of new reserves. Reserves added during the year replaced 286% of production (270% excluding pricing revisions).

Development

Development projects include recompletions, infill drilling and to a lesser extent, installation of secondary recovery projects. Drilling prospects are geographically diverse and target a mix of potential oil and gas formations at varying depths. Development 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. The following table sets forth the development inventory at December 31, 2003 by division:

	Development Projects		
	Drilling Locations	Recompletion Opportunities	Total
Southwest	169	166	335
Gulf Coast	13	34	47
Appalachia	1,701	52	1,753
Total	1,883	252	2,135

Exploration

Onshore. The Company currently has 40 onshore exploration projects on its 448,000 (182,000 net) acres. Most of the projects cover multiple drilling prospects, some with a number of targeted formations.

Gulf of Mexico. The Company owns a license on a 3-D seismic database covering 800 contiguous blocks in the shallow water of the Gulf of Mexico, primarily offshore Louisiana. In 2001, a joint venture was formed with two other companies to reprocess the data to identify and pursue exploration and development opportunities within a 4.0 million acre area. Range holds a 25% interest in the joint venture. The joint venture was awarded two blocks in the March 2001 lease sale. The joint venture plans to participate in at least two additional wells in 2004. The Company has also drilled one successful well using these data and plans to drill one additional well in 2004. The Company s current offshore leasehold inventory includes 37,000 gross (11,000 net) acres. To more fully exploit the seismic data base, it will be necessary to lease or farm-in additional acreage. To date, the joint venture has identified 39 specific prospects and leads on acreage not currently controlled. These projects generally target Miocene and Pliocene formations at depths ranging from 3,000 to 16,000 feet.

Oil and Gas Sales

Production revenue is generated through the sale of natural gas, crude oil and natural gas liquids (NGLs) from properties owned directly or through partnerships and joint ventures. The Company receives additional revenue from royalties. Production is sold to a number of purchasers, of which three account for more than 10% of oil and gas revenues. These three purchasers accounted for 49% of oil and gas revenues in 2003. The Company believes that the loss of any individual customer would not have a long-term material adverse effect. Proximity to local markets, availability of competitive fuels and overall supply and demand are factors affecting the prices that production can be marketed. Factors outside the Company s 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.

On an mcfe equivalent volume basis, 75% of the Company s 2003 production was natural gas. Gas is sold to utilities, marketing companies and industrial users. Gas sales are made pursuant to various contractual arrangements including month-to-month, one to three-year contracts at fixed or variable prices and, to a small extent, fixed prices for the life of the well. Contracts, other than those with fixed prices, contain provisions for price adjustment, termination and other terms customary in the industry. Oil is sold under contracts that can be terminated on 30 days notice. The price received 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. In 2003, gas revenues totaled $171.3 million or 76% of oil and gas revenues while revenues from oil and natural gas liquids totaled $55.1 million. Oil and gas revenues in 2003 increased 19% from the prior year due to higher production and higher prices.

Transportation, Gathering and Marketing

Transportation, gathering and marketing revenues are comprised of fees for the gathering and transportation of gas as well as oil and gas marketing income. Transportation, gathering and marketing revenues were $3.5 million in 2003, roughly level with the prior year. Gas transportation and gathering assets include (i) 50% ownership in approximately 5,000 miles of gas pipelines in Appalachia held through Great Lakes and (ii) a number of smaller gathering systems associated with producing properties outside of Appalachia. The Appalachian gathering systems transport a majority of Great Lakes gas production as well as third party gas to major trunk lines and directly to end-users. Third parties who transport gas through the gathering systems are charged a fee based on throughput.

The Company markets its own gas production and attempts to reduce the impact of price fluctuations through hedging. Approximately 1% of gas production is currently sold pursuant to fixed price end-user contracts at prices ranging from $1.25 to $7.28 per mcf (averaging $3.88 per mcf). The remaining 99% of gas production is sold at market (generally local index) related prices.

Hedging

The Company enters into hedging agreements to reduce the impact of volatile oil and gas prices. These contracts are entered into solely to hedge prices. Historically, the Company used swap agreements to hedge its production. In 2003, the Company began to use a combination of swap and collar arrangements. At December 31, 2003, hedges were in place covering 52.6 Bcf of gas at prices averaging $4.13 per mcf, 1.4 million barrels of oil at prices averaging $25.74 per barrel and 0.7 million barrels of NGLs at prices averaging $21.02 per barrel. The Company also has collars covering 6.6 Bcf of gas at weighted average floor and cap prices $4.14 to $6.19 and 1.2 million barrels of oil at weighted average floor and cap prices of $24.16 to $29.24. The fair value of the hedges, represented by the estimated amount that could be realized on immediate termination, approximated a pretax loss of $70.6 million at December 31, 2003. This loss is presented on the Company s Consolidated Balance Sheet as a net short-term unrealized loss of $53.7 million and a long-term unrealized loss of $16.9 million. Realized hedging gains and losses are determined monthly as hedges are financially settled and are included as increases or decreases in oil and gas revenues in the period the hedged production is sold. The realized loss relating to hedging in 2001 was $6.2 million. A hedging gain of $17.8 million was realized in 2002. A hedging loss of $60.4 million was realized in 2003. Changes in the value of the ineffective portion of all open hedges are recognized in earnings quarterly. Unrealized gains or losses on hedging contracts are recorded at an estimate of fair value based on a comparison of the contract price and a reference price, generally NYMEX, on the Company s Consolidated Balance Sheet as other comprehensive income (loss) (OCI), a component of stockholders equity. Through Great Lakes, the Company also has interest rate swap agreements (see Notes 6 and 7 to the Consolidated Financial Statements).

Independent Producer Finance (IPF)

IPF is a wholly owned subsidiary that provides capital to small oil and gas producers in exchange for dollar-denominated term overriding royalty interests. At year-end 2003, IPF s portfolio included 19 transactions having an aggregate book value of $12.6 million (net of $9.6 million of valuation allowances). The book value of the portfolio declined 48% in 2003 primarily due to $12.1 million of repayments received during the year. Since 2001, IPF has not entered into any new investment agreements and therefore, the portfolio should continue to decline from repayments, although IPF continues to fund requirements on existing transactions. The oil and gas reserves underlying

IPF s royalties are not included in the Company s reported proved reserves.

IPF provides valuation allowances against receivables that may not be recoverable. Increases and decreases in valuation allowances are reported as expenses. The IPF valuation allowance was increased $1.7 million, $4.2 million and $2.0 million in 2003, 2002 and 2001, respectively. IPF expenses also include general and administrative costs and interest expense. As dollar-denominated royalties, the transactions leave a portion of the commodity price risk with the producer. However, when price declines occur, IPF is exposed to losses. In addition, IPF is fully exposed to the individual operator s ability to successfully produce and develop the underlying reserves.

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Other Revenues

Other revenues is composed of ineffective hedging gains or losses, gains or losses on sale of assets and interest earned on cash balances and certain receivables. During 2003, other revenue amounted to a loss of $1.3 million including $1.2 million of ineffective hedging losses. During 2002, other revenue totaled a loss of $2.9 million which included $2.7 million of ineffective hedging losses, a $1.2 million write-down of marketable securities and a $715,000 favorable arbitration settlement. During 2001, other revenue totaled $490,000 and included $2.3 million of ineffective hedging gains and a $689,000 gain on asset sales offset by a $1.7 million write-down of marketable securities and a $1.4 million bad debt expense related to hedges utilizing Enron as the counterparty.

Competition

The Company encounters substantial competition in acquiring oil and gas leases, marketing production, securing personnel and conducting drilling and field operations. Competitors in exploration, development, acquisitions and production include the major oil companies as well as numerous independents, individual proprietors and others. Many competitors have financial and other resources substantially exceeding those of the Company. 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 the Company permit. The ability of the Company to replace and expand its reserve base depends on its ability to attract and retain quality personnel, identify and acquire suitable producing properties and prospects for future drilling.

Historically, acquisitions have generally been financed through bank borrowings, the issuance of debt and equity securities and internally generated cash flow. Debt and equity markets are cyclical as is the price of oil and gas. The ability of the Company to obtain financing on satisfactory terms is sometimes uncertain and can be affected by numerous factors beyond its control. The inability of the Company to raise satisfactorily priced external capital in the future could have a material adverse effect on its business.

Governmental Regulation

The Company s 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 the Company believes it is in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, the Company is unable to predict the future cost or impact of complying.

Securities Exchanges

Since 1998, 15.4 million shares of common stock have been issued in exchange for debt and convertible securities. The shares were exchanged for $96.7 million face value of 8.75% senior subordinated notes (the 8.75% Notes), 6% convertible subordinated debentures (the 6% Debentures), 5.75% trust preferred securities (the Trust Preferred Securities) and $2.03 convertible preferred stock (the $2.03 Preferred Stock). In September 2003, the Company exchanged $10.2 million in cash and $50.0 million of the newly issued Convertible Preferred for $79.5 million of the Trust Preferred Securities. The extent of any future dilution from exchanges will depend on a number of factors, including the number of shares issued, the price at which stock is issued or any newly issued securities are convertible into common stock and the price at which debt and convertible securities are reacquired.

Environmental Matters

The Company s 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 (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 the Company s operations and financial position, as well as the industry in general. Management believes the Company is in substantial compliance with current applicable environmental laws and regulations. Although the Company has not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. The Company did not have any material capital expenditures in connection with environmental remediation matters in 2003, nor does it anticipate that such expenditures will be material in 2004.

The Comprehensive Environmental Response, Compensation and Liability Act (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 the owner or operator 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 liabilities 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 the Company. 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 environment under environmental statutes, common law or both.

The Federal Water Pollution Control Act (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 the Company s 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 (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, the Company does not expect to experience more burdensome costs than similarly situated companies.

The U.S. Oil Pollution Act (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 statutes.

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 the Company s operating costs, as well as the industry in general. Compliance with environmental requirements generally could have a material adverse effect on the capital expenditures, earnings or competitive position of the Company. Although the Company has not experienced any material adverse effect from compliance with environmental requirements, no assurance may be given that this will continue.

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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 by the Company with the Securities and Exchange Commission (SEC), as well as information included in oral statements or other written statements made or to be made by the Company 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 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 the Company undertakes 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 the Company or on its behalf.

Oil and natural gas prices are volatile, and an extended decline in prices would hurt our profitability and financial condition

The oil and natural gas industry is cyclical, and prices for oil and natural gas are 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 fell, which contributed to losses we reported in those years. By early 2001, oil and natural gas prices reached levels above their historical norm. Prices declined in the second half of 2001 but have risen since mid-2002. 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 will likely be unable to replace production.

Common shareholders will be diluted if additional shares are issued

Since 1998, the Company has exchanged 15.4 million shares of common stock for $96.7 million of debt and convertible securities, including the Trust Preferred Securities, 6% Debentures, 8.75% Notes and $2.03 Preferred Stock. 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 were exchanged for common stock. During 2003, $880,000 of debt was exchanged for common stock. See Notes 6 and 18 to the Consolidated Financial Statements. While the exchanges have reduced interest expense, dividends and future repayment obligations, the larger number of common shares outstanding have a dilutive effect on existing shareholders. The Company s ability to repurchase securities for cash is limited by the $225.0 million secured revolving bank credit facility (the Senior Credit Facility) and the 7.375% senior subordinated notes (the 7.375% Notes) agreement. The Company continues to review alternatives to further strengthen its balance sheet by reducing debt and retiring securities. The Company may issue additional shares to fund capital expenditures, including acquisitions.

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Dividend restrictions

Restrictions on the payment of dividends and other restricted payments, as defined, are imposed under the Company s bank credit facility and the 7.375% Notes. Under the Senior Credit Facility, common and preferred dividends are permitted, subject to limitations. 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. The Senior Credit Facility provides for a restricted payment basket of $20.0 million plus 50% of net income (excluding Great Lakes) plus 66-2/3% of distributions, dividends or payments of debt from or proceeds from sales of equity interests of Great Lakes plus 66-2/3% of net cash proceeds from common stock issuances. As of December 31, 2003, the Company had $37.5 million available under the Senior Credit Facility restricted payment basket and $18.6 million available under the 7.375% Notes restricted payment basket.

Hedging transactions may limit our potential gains and involve other risks

To manage our exposure to price volatility, 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 limit volatility and increase the predictability of cash flow. These transactions may limit our potential gains if oil and natural gas prices were to rise over the price established by the hedge. At December 31, 2003, we were party to hedging arrangements covering 52.6 Bcf, 1.4 million barrels of oil and 0.7 million barrels of NGLs. The hedges fair value was a pretax unrealized loss of $70.6 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 contracts fail to perform under the contracts or a sudden, unexpected event materially impacts oil or natural gas prices.

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. The reserve data included or incorporated by reference is estimated. Although we believe these estimates are reasonable, actual production, revenues and reserve expenditures will likely vary from estimates, and these variances could be material.

The accuracy of any reserves estimate is a function of the quality of available data, engineering and geological interpretation and 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 value of the reserves.

If oil and natural gas prices decrease or drilling efforts are unsuccessful, we may be required to take writedowns 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 writedowns in the future. Writedowns may 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 and development costs or disappointing drilling results. Such downward adjustments may affect some properties more or less than others.

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 the assessment of fair value is less than the book value. 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 flow from operating activities, it reduces our earnings and increases our leverage ratios.

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, pipeline ruptures or spills, pollution, releases of toxic 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 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 for 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 opportunities and place us at a competitive disadvantage. At December 31, 2003, a portion of our borrowings, held through Great Lakes, were subject to interest rate swap agreements, which are above market, and therefore, increase our interest expense.

Our industry is highly competitive

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 major oil companies, independent exploration and 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. Generally these burdens do not appear to affect us to any greater or lesser extent than other companies in the oil and natural gas industry with similar types and quantities of properties in the same areas of the country.

Acquisitions by us are subject to the risks and uncertainties of evaluating recoverable reserves and potential liabilities

We could be subject to significant liabilities related to acquisitions by us. 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.

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 employment contracts. The loss of one or more of these individuals could have a material adverse effect on our business. Furthermore, competition for experienced technical employees is intense. If we cannot retain our current personnel or attract

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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 declines as reserves are depleted, our future success depends upon our ability to find or acquire additional oil and natural gas reserves that are economically recoverable. 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 is, therefore, 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 and develop or acquire additional reserves at an acceptable cost.

A portion of our business is subject to special risks related to offshore operation, generally in the Gulf of Mexico

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 expenditures 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. 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. One or more of the technologies that we currently use or that we may implement in the future may become obsolete, and we may be adversely affected.

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

The marketability of our oil and natural gas production depends in large 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 drilling 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 financial statements are complex

Due to new accounting rules, our financial statements continue to be complex, particularly with reference to hedging, asset retirement obligations and the accounting for the deferred compensation plan. The Company expects such complexity to continue and possibly increase.

Available Information

The Company maintains an internet website under the name www.rangeresources.com . The Company makes available, free of charge, on its 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, the Company s 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.

The Company files annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934. The public may read and copy any materials that the Company files 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 the Company, that file electronically with the SEC. The public can obtain any documents the Company files with the SEC at www.sec.gov.

Employees

As of January 1, 2004, the Company had 151 full-time employees, 55 of whom were field personnel. None are covered by a collective bargaining agreement. Management believes its relationship with employees is good.

ITEM 2. PROPERTIES

On December 31, 2003, the Company held working interests in 11,941 gross (6,080 net) productive wells and royalty interests in an additional 227 wells. Including its 50% share of Great Lakes reserves, its properties contained, net to its interest, estimated proved reserves of 486 Bcf of gas and 22 million barrels of oil and 11 million barrels of NGLs or a total of 685 Bcfe.

Proved Reserves

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

	December 31,				
	2003	**2002**	**2001**	**2000**	**1999**
Natural gas (Mmcf)					
Developed	344,187	320,224	276,162	305,796	299,437
Undeveloped	142,216	120,043	112,765	121,871	144,346
Total	486,403	440,267	388,927	427,667	443,783
Oil and NGLs (Mbbls)					
Developed	24,912	17,176	14,066	17,215	17,884
Undeveloped	8,111	5,776	6,614	8,787	10,933
Total	33,023	22,952	20,680	26,002	28,817

Total (Mmcfe)[a]	684,541	577,977	513,005	583,679	616,685
% Developed	72.1%	73.2%	70.3%	70.1%	66.0%

[a] Oil and NGLs are converted to mcfe at a rate of 6 mcf per barrel.

At December 31, 2003, 72.1% of the Company s proved reserves by volume were classified as developed and 27.9% were classified as undeveloped. The undeveloped reserves were located 58% in Appalachia, 28% in Southwest and 14% in the Gulf Coast regions.

At year-end 2003, the following independent petroleum consultants reviewed the Company s 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, 2003, these consultants collectively reviewed approximately 87% of the proved reserves. All estimates of oil and gas reserves are subject to uncertainty.

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 realized prices used in projecting them over the past five years (in millions except prices):

	December 31,				
	2003	2002	2001	2000	1999
Future net revenue	$2,687	$1,817	$ 750	$3,764	$1,013
Present Value					
Pretax	1,396	965	399	1,964	556
After tax	1,003	500	311	1,506	503
Oil price (per barrel)	$29.48	$27.52	$17.59	$24.46	$23.49
Gas price (per mcf)	$ 6.03	$ 4.76	$ 2.70	$ 9.57	$ 2.34

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, 2003. Weighted average product prices at December 31, 2003 were $29.48 per barrel of oil, $19.93 per barrel for natural gas liquids, and $6.03 per mcf of gas using benchmark NYMEX prices of $32.52 per barrel and $6.19 per Mmbtu. There can be no assurance that the proved reserves will be produced within the periods indicated and prices and costs will not 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 reserves have been filed with or included in reports to another federal authority or agency since year-end.

Significant Properties

The Company s operations are divided into three geographical divisions known as Southwest, Gulf Coast and Appalachia. The Appalachia division represents the Company s 50% ownership in Great Lakes. At year-end, the Company s properties included working interests in 11,714 (6,080 net) productive oil and gas wells, royalty interests in an additional 227 wells, and 834,000 (376,000 net) undeveloped acres. Of amounts included in the oil and NGL category, 68% is oil. The following tables sets forth summary information by division with respect to estimated proved reserves at December 31, 2003:

	Pretax Present Value		Volumes			
	Amount (In thousands)	%	Oil & NGL (Mbbls)	Natural Gas (Mmcf)	Total (Mmcfe)	%
Southwest	$ 668,489	48	26,175	187,188	344,238	50
Appalachia	489,911	35	5,527	228,427	261,589	39
Gulf Coast	237,416	17	1,321	70,788	78,714	11
Total	$1,395,816	100	33,023	486,403	684,541	100

December 31, 2003

	Southwest	Appalachia	Gulf Coast	Total
Natural gas (Mmcf)				
Developed	163,232	134,000	46,955	344,187
Undeveloped	23,956	94,427	23,833	142,216
Total	187,188	228,427	70,788	486,403
Oil and NGLs (Mbbls)				
Developed	21,195	2,886	831	24,912
Undeveloped	4,980	2,641	490	8,111
Total	26,175	5,527	1,321	33,023
Total (Mmcfe)[a]	344,238	261,589	78,714	684,541

[a] Oil and NGLs are converted to mcfe at a rate of 6 mcf per barrel.

Southwest division

The Southwest division conducts 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. This region represents 48% of the Company s total reserves by value and 50% by volume. Proved reserves in the Southwest division totaled 344 Bcfe, of which

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54% was gas. Reserves increased 104.6 Bcfe, a 44% increase over 2002 due to purchases, additions, favorable revisions based upon well performance and higher commodity prices. The region s daily production totaled 78.2 Mmcfe per day, representing 49% of total production. On an annual basis, production increased 9% over 2002. At year-end, the Southwest division had an inventory of 166 proven recompletions and 169 proven drilling locations. Acreage owned in the region at that date included 256,000 (194,000 net) developed acres and 154,000 (112,000 net) undeveloped acres. During 2003, 99 (86.4 net) development wells were drilled in the region, of which 85 (76.1 net) were productive and 5 (4.3 net) exploratory wells were drilled, of which 1 (1.0 net) was productive. During the year, the region achieved an 85% drilling success rate.

In West Texas, in the Conger Field of Sterling County, the Company added approximately 86 Bcfe in reserves in 2003. Drilling added 5.9 Bcfe as 12 (11.2 net) wells were drilled, of which 10 (9.2 net) were successful. Another 80 Bcfe in reserves were added in December 2003, when the Company completed an $87.1 million producing property acquisition adjacent to its current operations. The acquisition, which established Range as the largest operator in the field, added 500 operated wells to Range s existing 300 wells. Production from the acquired properties is expected to exceed 22 Mmcfe per day, while total field production is expected to reach 35 Mmcfe per day in 2004. The properties encompass 38,000 (32,000 net) acres and include a 400-mile gathering system. To date, the Company has identified 64 drilling locations and has plans to drill a number of them in 2004. At the Fuhrman-Mascho field in Andrews County, where a waterflood redevelopment project was undertaken in 2002, a total of 27 (26.0 net) producers and 11 (11.0 net) injectors have been successfully drilled. At year-end, the combined daily production rate from the field was approximately 8.5 Mmcfe per day. In total, 2003 drilling added 13 Bcfe in reserves to the field. A response to the waterflood is expected by the end of 2004. Even if the waterflood fails to yield a positive response, primary production has proved to be economic. If the waterflood does yield a positive response, a multi-phase expansion project is planned. At Powell Ranch in Glasscock County, 3 (2.2 net) wells were drilled, of which 1(0.2 net) was successful. At year-end, production from that field totaled 6.9 net Mmcfe per day. In the Val Verde Basin, a recompletion program in 2003 added 1.8 Mmcfe per day to production. In addition, 8 (7.0 net) wells were drilled, of which 6 (5.5 net) were successful. By year-end, production from Range s 202 wells in the Val Verde Basin totaled 14.5 (10.1 net) Mmcfe per day.

In East Texas, the second and third phases of a high-volume lift program were completed in 2003 in the Laura LaVelle field in Houston County. A fourth phase is currently underway. The project is designed to expand the field s water disposal system and facilitate increased pumping capacity. With 13 (12.8 net) shallow wells drilled in the field at average depths of 2,000 feet last year, production increased 18% to 4.4 (4.0 net) Mmcfe per day at year-end. In 2004, there are 3 (3.0 net) exploratory wells planned to test several medium-depth formations including the Wilcox, Woodbine and Buda formations in Houston County, at depths ranging between 6,000 and 11,000 feet. In Tyler County, Range has identified 4 (1.75 net) deeper Woodbine prospects on existing properties. These Woodbine wells target formations at depths in excess of 14,000 feet. In the James Lime trend of East Texas, 3 (2.0 net) wells drilled in 2003, of which 2 (1.5 net) proved successful.

In the Texas Panhandle, the Morrow play in the Texas Panhandle continued to yield significant production and reserve growth for Range in 2003. Drilling success in the area resulted in a net 62% increase in production for the area compared to the previous year-end. Equally important, strategic leasehold purchases during 2003 increased Range s acreage position in the play to 69,000 (52,000 net) acres, adding in excess of 20 potential drilling locations. In addition, the Company has acquired 912 miles of 2-D seismic data covering the field that is currently being processed and interpreted. Range continues to pursue the acquisition of additional acreage in the area. The division drilled 21 (17.7 net) Morrow wells in the Texas Panhandle in 2003, achieving an 84% success rate. The 17 (14.8 net) successful wells are currently producing at a net of 8.6 Mmcfe per day. In 2004, a total of 21 (14.5 net) wells are planned in the area to test various formations including Morrow, Hunton, Woodford and Brown Dolomite.

In the Anadarko Basin, Range drilled a total of 10 (5.6 net) wells in the Watonga-Chickasha trend of the Anadarko Basin, achieving a 98% success rate. The most notable successes were 6 (4.0 net) wells drilled on undeveloped leasehold acquired by Range in late 2002. The net production rate for the six wells at December 2003 was 2.7 Mmcfe per day. A total of 9 (4.3 net) wells are planned in this trend in 2004. The division also has plans in 2004 to test several deeper and higher potential prospects in western Oklahoma.

Gulf Coast division

The Gulf Coast division represents 17% of total Company reserves by value and 11% by volume. Proved reserves totaled 78.7 Bcfe, a decrease of 8% compared to 2002. During the year, the region s production totaled 45.2 Mmcfe per day. Gulf Coast reserves are 90% natural gas. Properties are located in the shallow waters of the Gulf of Mexico and onshore in Texas, Louisiana and Mississippi. The division s wells are characterized by high initial rates and relatively short reserve lives. Production by the Gulf Coast division represented 28% of the Company s total. 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

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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. Range operates a majority of its onshore properties while third parties operate its offshore properties. Offshore properties include interests in 37 platforms in water depths ranging from 11 to 240 feet. The Gulf Coast s development inventory includes 34 recompletions and 13 drilling locations on 129,000 (43,000 net) developed acres and 54,000 (14,000 net) undeveloped acres.

In 2003, the region spent $20.1 million to drill 4 (1.7 net) wells, recomplete 12 (3.6 net) others and to upgrade facilities. In the fourth quarter of 2003, net production averaged 647 barrels of oil and 42.4 Mmcf of gas per day or 46.2 Mmcfe per day in total. Production during the year increased 1% to 45.2 Mmcfe per day, reversing a 22% decrease in production from the previous year. With minimal drilling in 2003 and no acquisitions, the division replaced only 58% of production. During 2003, 1 development well (0.5 net) was drilled, which was productive. Three exploratory wells (1.2 net) were drilled with 2 (1.1 net) proving productive.

No new offshore wells were drilled in 2003, but work progressed to set up several significant wells for 2004 drilling. The joint venture formed between Range and two other companies continued to explore the central shelf of the Gulf of Mexico. Since forming the joint venture in 2001, $3.1 million has been spent on seismic data. The joint venture increased its total 3-D seismic data coverage from 6,100 square miles to 6,250 square miles in 2003 and the joint technical team continues to work the data, with a total number of 43 identified prospects. The joint venture continues to pursue leases and farm-ins to capture these leads and successfully secured leases in the March 2003 government sale that will allow for 2004 drilling of 2 (0.3 net) exploration wells. Range owns a 14% working interest in both prospects, which are on trend with other producers. The joint venture also secured a farm-in that will drill in the first half of 2004. Range owns a 10.5% working interest in this prospect.

Outside of the joint venture, Range is participating in 3 (0.8 net) offshore wells in the first quarter of 2004. The Chandeleur 17 S/L 17619#1 and the High Island 111 A-10 Sidetrack both reached total depth and set production casing in January, with production expected in March. The West Cameron 56 #17, an initial offset to the Company s 2002 West Cameron discovery, began drilling in January. If successful, this fault-separated offset could prove up two additional locations. In addition, the Falcon Prospect, located on East Cameron Block 33, is scheduled to spud later in 2004. This high risk/high reward project exposes Range to significant reserves at a potential net dry hole cost of $2.6 million. The Company retains a 25% working interest to casing point and a 37% working interest after casing point. Finally, Range has partnered with ExxonMobil licensing a portion of their 3-D seismic shoot of the old West Delta #30 field. Range has identified several leads. The first development location, a sidetrack, is scheduled to drill in the first quarter of 2004. Range retains a 49% interest in the field.

Onshore, Range had a successful year, increasing onshore production by 16%. Using state-of-the-art seismic technology to reprocess 3-D data and through skillful interpretation of subtle reflectors, the technical team successfully identified and drilled several high-rate producers. The team will attempt to replicate their success utilizing 500 square miles of reprocessed 3-D seismic covering onshore south Louisiana to search for additional opportunities overlooked with predecessor technologies.

Following up on a Marg howei discovery well drilled in south Louisiana in late 2002, 2 (0.9 net) additional wells were successfully drilled in 2003. All three wells have been prolific producers, with cumulative total production through year-end of 6.6 (2.1 net) Bcfe. Another South Louisiana well, the Hubbard #1, a 14,000 foot Nonion Struma test, spud in November and is currently drilling. Range has a 21% working interest in the prospect. In addition, 1 (0.6 net) well is planned in the South Louisiana area in the first quarter of 2004. In the Gulf Coast area, Range had exploration success with another seismically defined prospect. Range drilled a 14,500 foot well in late 2003, encountering 55 net feet of pay. Range owns 68% working interest in the well, which recently tested at 7.4 (3.7 net) Mmcfe per day with reservoir pressure of 9,300 pounds. Finally, one Vicksburg exploration well, in which Range owned a 10% working interest, was drilled in Orange County and proved unproductive. The Gulf Coast 2004 drilling program includes the drilling of 13 (3.7 net) offshore wells and 5 (2.4 net) onshore wells.

Appalachian division

Through its 50% interest in Great Lakes, the Appalachia division represents 262 Bcfe of proved reserves, or 39% by volume and 35% by value of total proved reserves. The region has a working interest in 9,175 gross (4,096 net) wells and approximately 5,000 miles of gas gathering lines. At December 31, 2003, Great Lakes had an inventory 1,701 proven drilling locations and of 52 proven recompletions.

	Development Projects		
	Drilling Locations	Recompletion Opportunities	Total
Beginning of 2003	1,665	68	1,733
Drilled	(143)		(143)
Added	279		279
Deleted & other	(100)	(16)	(116)
End of 2003	1,701	52	1,753

Acreage owned in the Appalachian region at December 31, 2003 included 869,000 (415,000 net) developed acres and 627,000 (249,000 net) undeveloped acres. During 2003, 238 (105.1 net) development wells were drilled, of which 236 (104.1 net) were productive. Twelve (2.8 net) exploratory wells were drilled, of which 8 (1.8 net) were productive. At December 31, 2003, Great Lakes operated 99% of its wells. The reserves are 87% gas and produce principally from the Upper Devonian, Medina, Clinton, Knox and Oriskany formations at depths ranging from 2,500 to 7,000 feet. For the year, net daily production averaged 30.6 Mmcfe of gas and 852 barrels of oil, or a total of 35.7 Mmcfe per day. The division s properties, with 1,753 proven projects at year-end, are located in the Appalachian and, to a minor extent, the Michigan Basins of the northeastern United States. After initial flush production, these properties are characterized by gradual decline rates, producing on average for 10 to 35 years.

In 2003, $20.9 million in capital funded the drilling of 238 (105.1 net) shallow development wells, 9 (2.2 net) medium depth exploration wells and 3 (0.6 net) deep exploration wells. In addition, capital was expended on one (0.5 net) recompletion as well as the purchase of 219 miles of seismic data and 258,000 (86,000 net) acres of leasehold. Of the 238 development wells drilled, 236 were successful. Eight of the 12 exploration wells were also successful, indicating an overall 98% success rate. Year-end proved reserves increased approximately 4% to 262 Bcfe as a result of acquisitions, additions and higher commodity prices.

The majority of the division s drilling expenditures are directed toward two large shallow-development plays which include the Clinton-Medina and Upper Devonian sandstone trends. In 2003, Great Lakes drilled 156 (68.3 net) wells in the Clinton-Medina and 70 (31.0 net) wells in the Upper Devonian shallow plays with an overall success rate of 99%. Approximately 89% of the division s capital budget will target shallow drilling in 2004, funding the drilling of 157 (68.2 net) Clinton-Medina wells and 88 (44.0 net) Upper Devonian wells.

In 2003, the division focused on expanding its shallow play development areas. A total of 18 (9.0 net) wells were drilled to test five new shallow development areas. Fifteen (8.0 net) of the test wells were successful, resulting in the extension of two existing fields and establishing at least three new development areas. To date, as many as 40 potential drill sites have been identified in the new development plays. Continued testing of the new areas, as well as leasing activity is planned in 2004.

Approximately 11% of the division s 2003 capital budget targeted both developmental and exploratory drilling to medium and deep plays. In 2003, a total of 12 (2.8 net) exploratory wells were drilled to medium/deep targets, of which 8 (1.8 net) were successful. Highlights include a Trenton-Black River discovery in New York that establishes a new field in an area where the Company owns 50,000 (25,000 net) acres. The well is currently shut-in awaiting pipeline connection. In addition, 2 (0.6 net) Oriskany sandstone discoveries were made in southwestern and north central Pennsylvania. These wells are currently shut-in awaiting pipeline connection or are producing under restricted pipeline conditions. In 2004, the Company plans to drill 14 (4.7 net) exploratory wells, including 5 (1.1 net) to the Trenton-Black River trend, 3 (0.8 net) of which have anticipated well depths above 4,500 feet.

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Production

The following table sets forth total Company production and related information for the past five years (in thousands, except average sales price and operating cost data).

	Year Ended December 31,				
	2003	2002	2001	2000	1999
Production					
Gas (Mmcf)	43,510	41,096	42,278	41,039	50,808
Crude oil (Mbbl)	2,023	1,873	1,916	2,035	2,247
Natural gas liquid (Mbbl)	401	407	326	363	412
Total (Mmcfe)[(b)]	58,053	54,772	55,730	55,427	66,762
Revenues					
Gas	$171,291	$144,030	$154,175	$118,977	$108,115
Crude oil	47,599	41,665	49,033	47,414	33,075
Natural gas liquids	7,512	5,259	5,646	6,691	4,302
Transportation and gathering	3,509	3,495	3,435	5,306	7,770
Total	229,911	194,449	212,289	178,388	153,262
Direct operating expenses[(a)]	49,317	40,443	43,430	40,552	43,074
Gross margin	$180,594	$154,006	$168,859	$137,836	$110,188
Average sales price (excluding hedging)					
Gas (per mcf)	$ 5.10	$ 3.02	$ 3.91	$ 3.71	$ 2.24
Crude oil (per bbl)	28.42	23.34	23.34	28.15	16.21
Natural gas liquid (per bbl)	18.75	12.93	17.33	18.43	10.44
Total (per mcfe)[(b)]	4.94	3.16	3.87	3.90	2.34
Average sales price (including hedging)					
Gas (per mcf)	$ 3.94	$ 3.50	$ 3.66	$ 2.90	$ 2.13
Crude oil (per bbl)	23.53	22.25	25.55	23.30	14.72
Natural gas liquids (per bbl)	18.75	12.93	17.33	18.43	10.44
Total (per mcfe)[(b)]	3.90	3.49	3.75	3.12	2.18
Operating costs (per mcfe)					
Direct	$ 0.68	$ 0.63	$ 0.67	$ 0.62	$ 0.58
Severance and production taxes	0.17	0.11	0.11	0.11	0.07

Total	$ 0.85	$ 0.74	$ 0.78	$ 0.73	$ 0.65

[a] Includes severance, production and ad valorem taxes.

[b] Oil and NGLs are converted to mcfe at a rate of 6 mcf per barrel.

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Producing Wells

The following table sets forth information (including the Company s 50% share of Great Lakes) relating to productive wells at December 31, 2003. The Company owns royalty interests in an additional 227 wells. Wells are classified as oil or gas according to their predominant production stream.

	Wells		Average Working Interest
	Gross	Net	
Crude oil	2,290	1,574	69%
Natural gas	9,651	4,506	47%
Total	11,941	6,080	51%

Acreage

The following table sets forth acreage held at December 31, 2003.

	Acres		Average Working Interest
	Gross	Net	
Developed	1,254,542	651,754	52%
Undeveloped	833,876	375,838	45%
Total	2,088,418	1,027,592	49%

Drilling Results

The following table summarizes drilling activity for the past three years.

	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	322.0	180.7	294.0	162.3	256.0	112.9
Dry	16.0	11.4	6.0	4.1	8.0	5.5
Exploratory wells						

Productive	11.0	3.8	17.0	6.9	6.0	1.9
Dry	9.0	4.4	11.0	5.3	2.0	0.9
Total wells						
Productive	333.0	184.5	311.0	169.2	262.0	114.8
Dry	25.0	15.8	17.0	9.4	10.0	6.4
Total	358.0	200.3	328.0	178.6	272.0	121.2
Success ratio	93%	92%	95%	95%	96%	95%

Real Property

The Company leases approximately 70,000 square feet of office space primarily in Texas and Oklahoma under standard office lease arrangements that expire at various dates through September 2007. All facilities are believed adequate to meet the Company s current needs and existing space could be expanded or additional space could be leased if required. The Company owns various vehicles and other equipment that are used in its field operations. Such equipment is believed to be in good repair and can be readily replaced if necessary.

ITEM 3. LEGAL PROCEEDINGS

The Company is involved in various legal actions and claims arising in the ordinary course of business, which includes a royalty owner suit filed in 2000 asking for class action certification against Great Lakes and the Company. Through 2003, total cumulative legal costs associated with the Great Lakes class action were $750,000. During 2003, approximately $450,000 of costs were incurred in defense of litigation. In the opinion of management, such litigations and claims are likely to be resolved without a material adverse effect on the Company s financial position or results of operations.

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 2003.

PART II

ITEM 5. MARKET FOR COMMON STOCK AND RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASE OF EQUITY SECURITIES

The Company s common stock is listed on the New York Stock Exchange (NYSE) under the symbol RRC. During 2003, trading volume averaged 179,500 shares per day. The following table sets forth the quarterly high and low sales prices and volumes as reported on the NYSE composite tape for the past two years.

	High	Low	Average Daily Volume
2002			
First quarter	$5.45	$4.03	155,882
Second quarter	5.91	4.95	160,475
Third quarter	5.68	4.05	145,836
Fourth quarter	5.96	4.05	108,856
2003			
First quarter	$6.20	$5.00	136,836
Second quarter	7.43	5.60	185,490
Third quarter	7.35	5.98	161,659

Fourth quarter	9.86	6.80	232,230

Between January 1, 2004 and February 26, 2004, the common stock traded at prices between $9.38 and $11.28 per share. The Company s 7.375% Notes, 6% Debentures, and 5.90% cumulative convertible preferred stock (the Convertible Preferred) are not listed on an exchange, but trade over-the-counter.

Historically, the Company has issued common stock in exchange for debt and convertible securities. Shares of common stock issued in such exchanges were exempt from registration under Section 3(a)(9) of the Securities Act of 1933. The following table summarizes those exchanges for the past three years:

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	Face Amount ($000)			Common Stock Issued (000 s)		
Security Exchanged	2003	2002	2001	2003	2002	2001
8.75% Notes	$	$ 875	$ 3,385		175	754
6% Debentures	880	7,140	5,710	125	1,150	745
Trust Preferred Securities		2,400	2,850		283	291
$2.03 Preferred stock			5,425			767
	$880	$10,415	$17,370	125	1,608	2,557
Market value at date of exchange				$735	$8,242	$14,207

In September 2003, the Company exchanged $10.2 million in cash and $50.0 million of the newly issued Convertible Preferred for $79.5 million of the Trust Preferred Securities held by the largest holder of the Trust Preferred Securities. The exchange, including the issuance of the Convertible Preferred was exempt from registration under Section 3(a)(9) of the Securities Act.

Holders of Record

At February 26, 2004, there were approximately 2,800 holders of record of the common stock.

Dividends

The payment of dividends is subject to declaration by the Board of Directors and depends on earnings, capital expenditures and various other factors. The Senior Credit Facility and the 7.375% Notes allow for the payment of common and preferred dividends, with certain limitations. The Convertible Preferred is entitled to receive cumulative quarterly dividends at an annual rate of $2.95 per share. In December 2003, the Company announced it would begin paying cash dividends on its common stock at a quarterly dividend rate of one cent per share. The first dividend was paid on January 30, 2004.

Equity Compensation Plans

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

	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]	3,831,135	$ 5.00	5,107,437

[a] Although the Company does not maintain a formal plan, common stock is issued to officers and key employees in lieu of cash for bonuses and company matches under the Company s 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 the Company s proxy statements.

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

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ITEM 6. SELECTED FINANCIAL DATA

The following table presents selected financial information for each of the last five years (in thousands, except per share data).

	Year Ended December 31,				
	2003	2002	2001	2000	1999
Balance sheet position at year-end:					
Current assets[(a)]	$ 66,092	$ 50,619	$ 77,735	$ 62,886	$ 77,521
Current liabilities[(b)]	106,964	67,206	47,879	53,221	57,441
Oil and gas properties, net	723,382	564,406	533,357	553,173	570,643
Total assets	830,091	658,484	682,462	671,826	732,228
Senior debt	178,200	115,800	95,000	89,900	140,000
Non-recourse debt	70,000	76,500	98,801	113,009	142,520
Subordinated debt	109,980	90,901	108,690	162,550	176,360
Trust preferred securities		84,840	89,740	92,640	117,669
Stockholders equity[(c)]	274,066	206,109	235,621	159,944	103,238
Weighted average dilutive shares outstanding	57,850	54,418	51,265	42,932	36,933

(a) 2001 includes a hedging asset of $37.2 million.

(b) 2003 and 2002 include hedging liabilities of $54.3 million and $2.6 million, respectively.

(c) Stockholders equity includes other comprehensive income (loss) of ($42.9 million), ($21.2 million), $45.5 million, ($639,000) and $189,000 in 2003, 2002, 2001, 2000 and 1999, respectively.

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Operations:

	Year Ended December 31,				
	2003	2002	2001	2000	1999
Revenues					
Oil and gas sales	$226,402	$190,954	$208,854	$173,082	$145,492
Transportation and gathering	3,509	3,495	3,435	5,306	7,770
IPF income	1,547	3,789	6,646	7,162	8,513
Gain on retirement of securities	18,991	3,098	3,951	17,763	2,430
Other	(1,252)	(2,900)	490	(722)	343
Gain on formation of Great Lakes					30,929
	249,197	198,436	223,376	202,591	195,477
Expenses					
Direct operating	36,423	31,869	34,884	32,457	37,401
Production and ad valorem taxes	12,894	8,574	8,546	8,095	5,673
IPF	2,965	6,847	3,761	1,974	6,389
Exploration	13,946	11,525	5,879	3,187	2,409
General and administrative	24,377	17,240	12,212	14,953	8,793
Interest expense and dividends on trust preferred	22,165	23,153	32,179	39,953	47,085
Debt conversion expense	465				
Depletion, depreciation and amortization	86,549	76,820	77,573	66,968	80,598
Provision for impairment			31,085		29,901
	199,784	176,028	206,119	167,587	218,249
Income (loss) before income taxes and accounting change	49,413	22,408	17,257	35,004	(22,772)
Income tax (benefit)					
Current	170	(4)	(406)	(1,574)	770
Deferred	18,319	(3,354)			
	18,489	(3,358)	(406)	(1,574)	770
Income before cumulative effect of change in accounting principle	30,924	25,766	17,663	36,578	(23,542)
Cumulative effect of change in accounting principle, net of taxes	4,491				
Net income (loss)	35,415	25,766	17,663	36,578	(23,542)

Gain on retirement of preferred stock			556	5,966	
Preferred dividends	(803)		(10)	(1,554)	(2,334)
Net income available to common shareholders	$ 34,612	$ 25,766	$ 18,209	$ 40,990	$ (25,876)
Net income (loss) available to common shareholders	$ 0.56	$ 0.49	$ 0.36	$ 0.97	$ (0.71)
Cumulative effect of change in accounting principle	0.08				
Net income (loss) per common share	$ 0.64	$ 0.49	$ 0.36	$ 0.97	$ (0.71)
Earnings per common share assuming dilution	$ 0.53	$ 0.47	$ 0.36	$ 0.96	$ (0.71)
Cumulative effect of change in accounting principle	0.08				
Net income (loss) per common share assuming dilution	$ 0.61	$ 0.47	$ 0.36	$ 0.96	$ (0.71)

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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).

	2002				
	March	**June**	**September**	**December**	**Total**
Revenues					
Oil and gas sales	$44,283	$48,626	$48,112	$49,933	$190,954
Transportation and gathering	774	924	1,037	760	3,495
IPF income	1,171	992	1,313	313	3,789
Gain on retirement of securities	1,185	845	1,050	18	3,098
Other	(2,009)	(1,235)	(125)	469	(2,900)
	45,404	50,152	51,387	51,493	198,436
Expenses					
Direct operating	7,516	7,672	8,542	8,139	31,869
Production and ad valorem taxes	1,688	2,266	1,974	2,646	8,574
IPF	1,772	2,178	808	2,089	6,847
Exploration	5,271	2,172	1,814	2,268	11,525
General and administrative	4,470	4,733	3,080	4,957	17,240
Interest expense and dividends on trust preferred	5,357	6,274	5,845	5,677	23,153
Depletion, depreciation and amortization	18,100	19,304	19,716	19,700	76,820
	44,174	44,599	41,779	45,476	176,028
Income before income taxes and accounting change	1,230	5,553	9,608	6,017	22,408
Income tax (benefit)					
Current		45	23	(72)	(4)
Deferred	(3,111)	(1,802)	363	1,196	(3,354)
	(3,111)	(1,757)	386	1,124	(3,358)
Net income	$ 4,341	$ 7,310	$ 9,222	$ 4,893	$ 25,766
Net income available to common shareholders	$ 0.08	$ 0.14	$ 0.17	$ 0.09	$ 0.49
Cumulative effect of change in accounting principle					

Net income per common share	$	0.08	$	0.14		0.17	$	0.09	$	0.49
Earnings per common share assuming dilution	$	0.08	$	0.13	$	0.17	$	0.09	$	0.47
Cumulative effect of change in accounting principle										
Net income per common share assuming dilution	$	0.08	$	0.13	$	0.17	$	0.09	$	0.47

The total of quarterly earnings per share does not necessarily equal the earnings per share for the year, because the calculations are based on the weighted average shares outstanding or rounding. (See Management s Discussion and Analysis Results of Operations.)

	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
IPF income	539	428	297	283	1,547
Gain on retirement of securities	150	(10)	18,572	279	18,991
Other	928	(1,913)	723	(990)	(1,252)
	56,974	54,718	76,156	61,349	249,197
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
IPF	618	568	578	1,201	2,965
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
Debt conversion expense	465				465
Depletion, depreciation and amortization	20,967	21,276	21,869	22,437	86,549
	47,921	47,663	50,398	53,802	199,784
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 shareholders	$ 9,454	$ 4,591	$16,672	$ 3,895	$ 34,612
Net income available to common shareholders	$ 0.09	$ 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	$ 0.31	$ 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	$ 0.31	$ 0.07	$ 0.61

The total of quarterly earnings per share does not necessarily equal the earnings per share for the year, because the calculations are based on the weighted average shares outstanding or rounding. (See Management s Discussion and Analysis Results of Operations.)

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

(Capitalized terms herein are defined in the footnotes to the Consolidated Financial Statements contained herein.)

Critical Accounting Policies and Estimates

The Company s discussion and analysis of its 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 the Company to make estimates and judgments that affect the amounts reported in the financial statements and related footnote disclosures. Application of certain of the Company s 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. The Company bases its estimates on historical experience and various assumptions that are believed reasonable under the circumstances. Actual results may differ from these estimates. The Company believes the following critical accounting policies reflect its more significant judgments and estimates used in the preparation of its financial statements.

Property, Plant and Equipment

Proved reserves are defined by the U.S. Securities and Exchange Commission (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 the Company s 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 the Company. The Company cannot predict what reserve revisions may be required in future periods. Reserve estimates are reviewed and approved by the Company s Vice President of Reservoir Engineering who reports directly to the Company s Chief Operating Officer. In addition, because substantially all of the Company s proved reserves are pledged as collateral for the Senior Credit Facility, the Company s estimates of proved reserves are reviewed twice annually by independent engineers on behalf of each of the eleven banks participating in the Senior Credit Facility. A similar reserve review is conducted by the banks participating in the Great Lakes debt facility. To further ensure the reliability of reserve estimates, the Company engages independent petroleum consultants to review the estimates of proved reserves. During 2003, 2002, and 2001, their review covered 87%, 84% and 82% of reserve value, respectively.

The Company utilizes the successful efforts method to account for exploration and development expenditures. Unsuccessful exploration wells are expensed and can have a significant effect on 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 the Company s engineers. The successful efforts method inherently relies upon the estimation of proved reserves, which includes proved developed and proved undeveloped volumes.

The Company adheres 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. The Company considers a combination of time and geologic and engineering factors to evaluate the need for impairment of these costs. Unproved properties had a net book value of $12.2 million, $19.0 million and $25.7 million in 2003, 2002 and 2001, 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 its oil and gas producing activities and reserve quantities disclosure in Note 19 to the Consolidated Financial Statements. Changes in the estimated reserves are considered changes in estimates for accounting purposes and are reflected on a prospective basis.

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The Company monitors its long-lived assets recorded in property, plant and equipment in the Consolidated Balance Sheet to ensure they are fairly presented. The Company must evaluate its 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, 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. The Company cannot predict whether impairment charges may be required in the future.

Derivatives

The Company uses commodity derivative contracts to manage its exposure to oil and gas price volatility. The Company accounts for its 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 (OCI) and then reclassified to earnings 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 used by the Company include commodity swaps and collars. While there is a risk that the financial benefit of rising prices may not be captured, management believes 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 the Company s ongoing development drilling and production enhancement programs, more consistent returns on invested capital, and better access to bank and other credit markets. Through Great Lakes, the Company also has interest rate swap agreements to protect against the volatility of variable interest rates under its credit facility.

Asset Retirement Obligations

The Company has significant obligations to remove tangible equipment and restore land or seabed at the end of oil and gas production operations. The Company s 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 the Company 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). The Company adopted this statement effective January 1, 2003, as discussed in Note 4 to the Consolidated Financial Statements. SFAS 143 significantly changed the method of accruing for costs an entity is legally obligated to incur related to the retirement of fixed assets (asset retirement obligations or ARO). Primarily, the new statement requires the Company to record a separate liability for the discounted present value of the Company s asset retirement obligations, with an offsetting increase to the related oil and gas properties on the Company s Consolidated Balance Sheet.

Inherent in the present 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 will be reflected as accretion expense in the 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. The Company, therefore, 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 the Company recorded as cumulative effect of change in accounting principle on January 1, 2003.

Deferred Taxes

The Company is subject to income and other taxes in all areas in which it operates. 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. The Company has deferred tax assets relating to tax operating loss carry forwards and other deductible differences. The Company routinely evaluates all deferred tax assets to determine the likelihood of realization. A valuation allowance is recognized on deferred tax assets when management believes 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 2002, deferred tax assets exceed deferred tax liabilities by $15.8 million with $11.4 million of deferred tax assets related to hedging losses included in OCI. 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 deferred hedging losses included in OCI. Based on the Company s 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 2003 valuation allowance was deemed necessary.

The Company may be is challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions on its various income tax returns. Although the Company believes that it has adequate accruals for unresolved tax matters, gains or losses could occur in the future due to changes in estimates or resolution of outstanding matters.

Contingent Liabilities

A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable, and the cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and contingent matters. In addition, the Company often must estimate the amount of such losses. In many cases, management s judgment is based on the input of its legal advisors and on the interpretation of laws and regulations, which can be interpreted differently by regulators and/or the courts. Management monitors known and potential legal, environmental and other contingent matters and makes its best estimate of when the Company should record losses for these based on available information.

Bad Debt Expense

The Company periodically assesses the recoverability of all material trade and other receivables to determine their collectability. At 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.

Revenues

The Company recognizes revenues from the sale of products and services in the period delivered. 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 the Company s control. Imbalances 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.

Other

The Company records 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 by the Company in its 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 the Company s exploration efforts are expensed as exploration expense. The Company does not capitalize general and administrative expense or interest expense.

Liquidity and Capital Resources

During 2003, the Company spent $206.9 million on exploration, development and acquisitions. In December 2003, the Company purchased, with borrowings under the Senior Credit Facility, producing oil and gas properties in Sterling County, Texas for approximately $87.1 million (including $2.1 million of asset retirement obligations). Bank facility debt increased $55.9 million in 2003 while other debt (including Trust Preferred Securities) was reduced by $65.8 million. At December 31, 2003, the Company had $631,000 in cash, total assets of $830.0 million and a debt to capitalization ratio of 57%. Available borrowing capacity on the Company s bank lines at December 31, 2003 was $46.7 million on the Senior Credit Facility and $85.0 million at Great Lakes (of which $42.5 million was net to Range). Long-term debt at December 31, 2003 totaled $358.2 million and included $178.2 million of borrowings under the Senior Credit Facility, $70.0 million under the non-recourse Great Lakes $275.0 million secured revolving bank facility (the Great Lakes Credit Facility), $98.3 million of 7.375% Notes and $11.6 million of 6% Debentures. At December 31, 2003, the Company had a working capital deficit of $40.9 million which included an unrealized hedging liability of $54.2 million due to the mark-to-market of all open hedges. Because payments on this hedging liability are made monthly, and the Company will also collect production proceeds to which this hedging relates and the amount should be self-funding.

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, $5.3 million of Trust Preferred Securities and $500,000 of 8.75% Notes were repurchased for cash. Also, $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. A $19.0 million gain was recorded, as the securities were retired at a discount.

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. The Company believes that net cash generated from operating activities and unused committed borrowing capacity under the credit facilities combined with the 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 the Company s ability to fund capital expenditures, reduce debt, meet financial obligations and remain profitable. The Company operates 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. The Company s ability to expand its 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.

The following summarizes the Company s contractual financial obligations at December 31, 2003 and their future maturities. The Company expects to fund these contractual obligations with cash generated from operating activities and refinancing proceeds.

	Payment due by period			
	2004		**Thereafter**	**Total**

		2005 and 2006	2007 and 2008		
			(in thousands)		
Long-term debt[a]	$	$	$259,849	$100,000	$359,849
Operating leases	2,567	3,747	699		7,013
Seismic purchase	1,236	215			1,451
Derivative obligations[b]	54,229	16,777			71,006
Asset retirement obligation liability	5,814	19,098	3,540	23,391	51,843
Total contractual obligations[c]	$63,846	$ 39,837	$264,088	$123,391	$491,162

(a) Due at termination dates for each of the Company s credit facilities, which the Company expects to renew, but there is no assurance that can be accomplished.

(b) Derivative obligations represent net open hedging contracts valued as of December 31, 2003.

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

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Total long-term debt at December 31, 2003, was $358.2 million. Long-term debt of $248.2 million was subject to floating interest rates (of which certain amounts have interest swap agreements) and $111.6 million of debt had a fixed interest rate. The table below describes the Company s required annual fixed interest payments on these debt instruments (in thousands):

Security	Amount	Annual Interest	Interest Payable	Maturity
7.375% Notes	$100,000	$7,375	January, July	2013
6% Debentures	11,649	699	February, August	2007
	$111,649	$8,074		

Cash Dividend Payments

In December 2003, the Company announced it would reinstate cash dividends on its common stock at an initial quarterly dividend rate of one cent per share. The first dividend was paid on January 30, 2004. The Convertible Preferred is entitled to receive cumulative quarterly dividends at an annual rate of $2.95 per share. The payment of dividends is subject to declaration by the Board of Directors and depends on earnings, capital expenditures and various other factors. The table below describes the Company s preferred dividend payments (in thousands):

Security	Amount	Annual Dividend	Dividend Payable
5.90% Convertible Preferred	$50,000	$2,950	Quarterly

Cash Flow

The Company s principal sources of cash are operating cash flow, bank borrowings and at times, issuance of debt and equity securities. The Company s cash flow is highly dependent on oil and gas prices. As of December 31, 2003, the Company has entered into hedging agreements covering 50.1 Bcfe, 28.9 Bcfe and 0.6 Bcfe for 2004, 2005 and 2006, respectively. The $106.0 million of capital expenditures for 2003, excluding acquisitions, was funded with internal cash flow. The amount expended replaced 130% of production. Including acquisitions, reserve replacement totaled 286% of production. The $126.0 million 2004 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 the Company s hedge position, the 2004 capital program is expected to be funded with internal cash flow.

Net cash provided by operations in 2003, 2002 and 2001 was $125.5 million, $114.5 million and $130.6 million respectively. In 2003, cash flow from operations increased with higher volumes and higher prices somewhat 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 somewhat offset by lower interest and direct operating expenses. In 2001, cash flow from operations increased with higher prices and lower interest expense somewhat offset by increasing operating and exploration expenses.

Net cash used in investing in 2003, 2002 and 2001 was $187.6 million, $103.9 million and $79.2 million, respectively. The 2003 period included $92.0 million 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 of additions to oil and gas properties and $5.1 million of IPF investments partially offset by $17.3 million of IPF receipts. The 2001 period included $78.5 million of additions to oil and gas properties and $11.6 million of IPF investments, partially offset by $19.0 million of IPF receipts and $3.8 million of asset sales.

Net cash used in financing (to repay debt) in 2003, 2002 and 2001 was $61.5 million, ($12.6 million) and ($50.6 million), respectively. Historically, sources of financing have been primarily bank borrowings and capital raised through equity and debt offerings. During 2003, recourse bank debt increased $62.4 million primarily due to the December acquisition of producing properties in the Conger field. For the year, total debt declined $9.9 million. During 2003, the Company 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, recourse bank debt increased $20.8 million and total debt (including Trust Preferred Securities) decreased by $24.2 million. Recourse debt increased due to the retirement of the IPF credit facility and the repurchase of debt and convertible securities with borrowings under the Senior Credit Facility. During 2001, recourse bank debt increased by $5.1 million and total debt (including Trust Preferred Securities) decreased by $65.9 million. The reduction in debt was the result of applying excess internal cash flow, proceeds from asset sales and exchanges of common stock for debt and convertible securities.

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Capital Requirements

The Company s 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 2003, $106.0 million of capital was expended, primarily on drilling projects. Also during 2003, $100.9 million was expended on acquisitions, including $90.7 million to purchase producing properties. The capital program, excluding acquisitions, was funded by of net cash flow from operations. The 2004 capital budget of $126.0 million is expected to increase production and expand the reserve base by more than replacing production. Development and exploration activities are highly discretionary, and, for the foreseeable future, management expects 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.

Bank Credit Facilities

The Company maintains two separate revolving credit facilities, a $225.0 million Senior Credit Facility and a $275.0 million Great Lakes Credit Facility (of which 50% is consolidated by the Company). Each facility is secured by substantially all the borrowers assets and matures on January 1, 2007. The Great Lakes Credit Facility is non-recourse to the Company. As Great Lakes is 50% owned, half of its borrowings are consolidated in the Company s financial statements. Availability under the facilities is subject to borrowing bases set by the banks semi-annually and in certain other circumstances. The borrowing bases are 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, 2004, the Senior Credit Facility had a $225.0 million borrowing base of which $42.4 million was available. The Great Lakes Credit Facility, half of which is consolidated by the Company, had a $225.0 million borrowing base of which $82.0 million was available.

Restrictions on the payment of dividends and other restricted payments as defined are imposed under the Company s bank credit agreement 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. The Senior Credit Facility provides for a restricted payment basket of $20.0 million plus 50% of net income (excluding Great Lakes) plus 66-2/3% of distributions, dividends or payments of debt from or proceeds from sales of equity interests of Great Lakes plus 66-2/3% of net cash proceeds from common stock issuances. The debt agreements contain covenants relating to net worth, working capital, dividends and financial ratios. The Company was in compliance with all covenants at December 31, 2003.

Hedging - Oil and Gas Prices

The Company enters into hedging agreements to reduce the impact of oil and gas price volatility on its operations. At December 31, 2003, hedges were in place covering 52.6 Bcf of gas at prices averaging $4.13 per mcf, 1.4 million barrels of oil at prices averaging $25.74 per barrel and 0.7 million barrels of NGLs at prices averaging $21.02 per barrel. The Company also has collars covering 6.6 Bcf of gas at weighted average floor and cap prices of $4.14 to $6.19 and 1.2 million barrels of oil at weighted average floor and cap prices of $24.16 to $29.24. 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 $70.6 million at December 31, 2003. 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 revenues in the period the hedged production is sold. Realized losses relating to hedging in 2001 were $6.2 million. A hedging gain of $17.8 million was realized in 2002. A hedging loss of $60.4 million was realized in 2003. 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 the Company s Consolidated Balance Sheet as OCI, a component of stockholders equity.

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At December 31, 2003, the following commodity derivative contracts were outstanding:

Contract Type	Period	Volume Hedged	Average Hedge Price
Natural gas	2004	91,440 MMBtu/day	$ 4.08
Swaps	2004	91,440 MMBtu/day	$ 4.08
Swaps	2005	50,695 MMBtu/day	$ 4.21
Swaps	2006	1,644 MMBtu/day	$ 4.80
Collars	2004	6,470 MMBtu/day	$ 4.38-$6.19
Collars	2005	11,517 MMBtu/day	$ 4.14-$5.80
Crude oil			
Swaps	2004	3,010 Bbl/day	$ 25.93
Swaps	2005	940 Bbl/day	$ 25.11
Collars	2004	2,128 Bbl/day	$24.18-$29.24
Collars	2005	1,233 Bbl/day	$24.16-$27.48
Natural gas liquids			
Swaps	2004	1,377 Bbl/day	$ 21.88
Swaps	2005	658 Bbl/day	$ 19.20

Interest Rates

At December 31, 2003, the Company had $358.2 million of debt outstanding. Of this amount, $110.0 million bears interest at fixed rates averaging 7.2%. Senior debt and non-recourse debt totaling $248.2 million bears interest at floating rates, which averaged 3.1% at year-end 2003, excluding interest rate swaps. At December 31, 2003, Great Lakes had $110.0 million subject to interest rate swap agreements, of which 50% is consolidated by the Company. These swaps consist of two agreements totaling $45.0 million at 7.1% which expire in May 2004, two agreements totaling $20.0 million at 2.3% which expire in December 2004, 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, 2003 was 1.1%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2003 would cost the Company approximately $1.9 million in additional annual interest, net of swaps.

Capital Restructuring Program

The Company took a number of steps beginning in 1998 to strengthen its financial position. These steps included the sale of assets and the exchange of common stock for debt and convertible securities. These initiatives have helped reduce total debt 51% from $727.2 million at December 31, 1998 to $358.2 million at December 31, 2003. The Company currently believes it has sufficient liquidity and cash flow to meet its obligations for the next twelve months; however, a drop in oil and gas prices or a reduction in production or reserves would reduce the Company s ability to fund capital expenditures and meet its financial obligations. Also, the Company s obligations may change due to acquisitions, divestitures and continued growth.

Off-Balance Sheet Arrangements

The Company does not have any off-balance sheet arrangements that are material to its financial position or results of operations.

Inflation and Changes in Prices

The Company s revenues, the value of its assets, its 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 the Company s ability to control or predict. During 2002, the Company received an average of $22.25 per barrel of oil and $3.50 per mcf of gas after hedging. During 2003, the Company received an average of $23.53 per barrel of oil and $3.94 per mcf of gas, after hedging. Although certain of the Company s costs and expenses are affected by the general inflation, inflation does not normally have a significant effect on the Company. However, industry-specific inflationary pressures built up over an 18-month period in 2001 and 2002 due to favorable conditions in the industry. During 2002, the Company 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. The Company expects an increase in these costs for 2004. Increases in commodity prices can cause inflationary pressures specific to the industry to also increase.

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Future Trends

The Company s strategy is to increase its oil and gas reserves, production, cash flow and earnings per share through a balanced program that involves:

- enhancing and increasing the base of existing properties;
- developing existing acreage position;
- investing in high-potential exploration prospects; and
- acquiring producing properties complementary to existing properties.

The Company has announced a $126.0 million 2004 capital budget excluding acquisitions. Range will continue to monitor commodity prices and adjust its capital expenditures accordingly. The Company will also continue to evaluate and pursue acquisition opportunities should they become available at reasonable prices.

A major trend over the past two decades has involved the divestiture of oil and gas properties located in the United States by major integrated oil companies and large independents. These companies have largely pursued growth internationally to achieve the size and economies of scale required of a large global enterprise and have sold or deemphasized older smaller properties in the United States. Many of these divested properties have not received significant recent capital investment and often newly available production and reserve enhancement technology has not been applied to these properties. In other situations, to increase cash flow without increasing capital spending, companies have allowed smaller firms such as Range the opportunity to explore and develop reserves on their undeveloped acreage through joint ventures. The pace of these initiatives by the large independents and major integrated oil companies has slowed significantly during the past five years as oil and gas price increases have improved the underlying economics of older properties. It is anticipated that as oil and gas prices plateau or decline and extraction costs continue to rise, larger oil companies will implement additional property divestitures and entertain additional joint ventures. This trend would increase the availability of acquisition, exploration and development opportunities for the Company. Should this trend not continue, the Company will continue to rely upon the ability of its technical teams to generate exploration and development prospects on existing Company owned acreage and acreage publicly available for lease.

Another major trend in the industry involves technological advances that reduce the cost to explore and produce oil and gas and also allow for extraction of oil and gas from reservoirs previously deemed unrecoverable. Examples of this technology include 3-D seismic, hydraulic reservoir fracture stimulation, advances in well logging and analysis, horizontal drilling and completion techniques, secondary and tertiary recovery practices, and automated well monitoring and control devices. These technology advances have served to lower exploration risk, reduce drilling and production costs and, on occasion, dramatically increase the amount of economically recoverable oil and gas reserves from existing reservoirs. While it is impossible to predict the continuation, pace and application of this trend to the Company s properties, the Company s large acreage position, experienced staff and geographically diversified property base, positions the Company well for future technological advances.

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Results of Operations

Volumes and Sales Data

	2003	2002	2001
Production:			
Crude oil (bbls)	2,023,158	1,872,654	1,916,073
NGLs (bbls)	400,631	406,746	325,803
Natural gas (mcfs)	43,510,180	41,095,976	42,278,430
Total (mcfe)	58,052,911	54,772,376	55,729,683
Average daily production:			
Crude oil (bbls)	5,543	5,131	5,250
NGLs (bbls)	1,098	1,114	893
Natural gas (mcfs)	119,206	112,592	115,831
Total (mcfe)	159,049	150,061	152,684
Average sales prices (excluding hedging):			
Crude oil (per bbl)	$ 28.42	$ 23.34	$ 23.34
NGLs (per bbl)	$ 18.75	$ 12.93	$ 17.33
Natural gas (per mcf)	$ 5.10	$ 3.02	$ 3.91
Total (per mcfe)	$ 4.94	$ 3.16	$ 3.87
Average sales prices (including hedging):			
Crude oil (per bbl)	$ 23.53	$ 22.25	$ 25.55
NGLs (per bbl)	$ 18.75	$ 12.93	$ 17.33
Natural gas (per mcf)	$ 3.94	$ 3.50	$ 3.66
Total (per mcfe)	$ 3.90	$ 3.49	$ 3.75

The following table identifies certain items included in the results of operation 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,		
	2003	**2002**	**2001**
		(in thousands)	
Increase (decrease) in revenues			
Write-down of marketable securities	$	$ (1,220)	$ (1,715)
Gains on retirement of securities	18,991	3,098	3,951
Loss on Enron contracts			(1,352)
Gain/(loss) on asset sales	(15)	161	689
Ineffective portion of commodity hedges gain (loss)	(1,238)	(2,730)	2,351
Realized hedging gains (losses)	(60,427)	17,790	(6,194)
Recovery from arbitration		715	

	$(42,689)	$17,814	$ (2,270)
Increase (decrease) in expenses			
Provision for impairment	$	$	$31,085
Mark-to-market deferred compensation expense[a]	6,559	1,023	(2,410)
Bad debt expense accrual	275	150	688
Non-qualifying interest rate swaps	(559)	275	1,403
Adjustment of IPF valuation allowance	1,819	4,240	122
	$ 8,094	$ 5,688	$30,888
Cumulative effect of change in accounting principle (net of taxes)	$ 4,491	$	$

[a] Represents the mark-to-market expense related to Company stock held in the deferred compensation plan.

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Overview

The business of exploring for, developing, and acquiring oil and gas is highly competitive and capital intensive. As in any commodity business, the market price of the commodity produced and the costs associated with finding, acquiring, extracting, and financing the operation are critical to profitability and long-term value creation for shareholders. Generating growth while containing costs represents an ongoing challenge for management, made particularly urgent by the natural production and reserve decline associated with oil and gas properties. During periods of historically high oil and gas prices, cost increases are more prevalent due to increased competition for goods and services. Other challenges faced by the Company include attracting and retaining qualified personnel and maintaining access to capital on sufficiently favorable terms. Enrollments in university oil and gas technology programs have declined over the past two decades as the industry has been wracked by business cycles and consolidation. Emerging industries, such as high technology, have increased the competition for favorably priced capital required by the oil and gas industry.

The Company has responded to these trends and challenges in many ways. The balance sheet has been restructured to increase cash flow available for investment through reduced debt, principal maturity extensions, and lower interest expense. The technical staff of the Company has been increased and strengthened through the hiring of additional experienced professionals and the use of teams. The inventory of exploration and development prospects has been increased to provide greater diversification of technical risk and better efficiency. The Company s multidiscipline technical teams have local expertise in their area of operation. This technical competence and local expertise provides a platform to compete and grow core areas from exploration, development and acquisitions.

The year ended December 31, 2003 was very good operationally. Production for the Company increased 6% versus the prior year. Range replaced 286% of production at $1.25 per Mcfe finding and development costs through a combination of both successful drilling and acquisition programs. The 286% production replacement caused the Company s reserve base to increase 18% to 685 Bcfe as of December 31, 2003.

The Company completed the acquisition of producing properties in the Conger Field in Sterling County, Texas on December 23, 2003. With this acquisition, the Company became the largest operator in the field with current net production of 32 Mmcfe per day and an acreage position of 69,000 gross acres. As a result of this acquisition, coupled with our ongoing drilling program, 2004 production is projected to increase over 2003.

The drilling inventory consists of a large number of low risk locations, coupled with projects that have higher risk and have the potential to positively impact the Company s reserves and production if successful. The inventory is also geographically diversified with projects in each of the three core areas: Southwest, Gulf Coast, and Appalachia. Our strategy calls for our baseline growth to be generated through drilling and for the acquisition of producing properties to provide incremental growth.

Comparison of 2003 to 2002

The year 2003 brought favorable operating and financial results, even though the Company realized a $60.4 million reduction in oil and gas revenue due to oil and gas hedging. On the operating side, oil and gas prices, production and proved reserves were all higher than 2002. A complementary acquisition adjacent to an existing Company owned property was completed in December 2003. With the transition from an acquisition focused strategy to a drilling based strategy coupled with complementary acquisitions, 2003 brought an increase in both acreage and seismic spending. On the financial side, enhancing the Company s financial position continued with retirement of the Trust Preferred Securities, refinancing of the 8.75% Notes, and a sizable proved reserve-driven increase in the Senior Credit Facility borrowing base. Debt carrying costs were reduced and maturities extended, increasing cash flow available for capital investment. The balance sheet enhancement also resulted in several large revenue and expense items related to the various transactions.

Net income in 2003 totaled $35.4 million compared to $25.8 million in 2002. A $19.0 million gain on retirement of debt and convertible securities was realized in 2003 versus $3.1 million in 2002. Total oil and gas revenues of $226.4 million were $35.4 million higher than 2002 due to 6% higher production and a 12% increase in average prices to $3.90 per mcfe. The average prices received for oil increased 6% to $23.53 per barrel and increased 13% to $3.94 per mcf for gas. Production expenses increased $4.5 million to $36.4 million as a result of higher workover costs and increased costs from acquisitions and new wells. Production taxes increased $4.3 million to $12.9 million due to higher prices and higher volumes. Since production taxes are paid based on market prices and not hedged prices, higher market prices caused production taxes per mcfe to increase 38% from the prior year. Operating cost (excluding production and ad valorem taxes) per mcfe produced averaged $0.63 in 2003 versus $0.58 in 2002.

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Transportation and gathering revenues of $3.5 million were approximately the same as 2002. IPF s income of $1.5 million declined 59% from 2002 due to a declining portfolio balance. During 2003, IPF expenses included $1.0 million of administrative expenses, $207,000 of interest and a $1.7 million increase in the valuation allowance. During 2002, IPF expense included $1.7 million of administrative costs, $937,000 of interest costs and a $4.2 million increase to the valuation allowance. Other revenue increased from a loss of $2.9 million in 2002 to a loss of $1.3 million in 2003. The 2003 period included $1.2 million of ineffective hedging losses. The 2002 period included $2.7 million ineffective hedging losses and a $1.2 million write-down of marketable securities, offset by a $715,000 arbitration recovery.

Exploration expense increased 21% to $13.9 million in 2003 primarily due to higher seismic purchases ($3.9 million) offset by lower dry hole costs ($1.7 million). General and administrative expenses increased 41% due to a $5.5 million increase in the non-cash mark-to-market deferred compensation expense and $1.6 million of higher salary and related benefit costs as well as higher director fees, legal and consulting fees and insurance costs.

Interest expense for 2003 decreased 4% to $22.2 million with the $2.0 million call premium on the 8.75% Notes (included in interest expense) offset by lower outstanding debt and lower interest rates. 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 amortization of unproved property costs. The per mcfe DD&A rate was $1.49, a $0.09 increase from 2002 with higher accretion expense ($0.08 per mcfe) and higher amortization of unproved property ($0.03 per mcfe). The DD&A rate is determined based on year-end reserves (based on NYMEX futures prices averaging $32.52 per barrel and $6.19 per mcf) and the net book value associated with them and, to a lesser extent, depreciation on other assets owned. The DD&A rate in the fourth quarter of 2003 was $1.48 per mcfe, reflecting year-end 2003 reserves.

Year-end 2003 includes a tax expense of $18.5 million versus a tax benefit of $3.4 million in the prior year. The prior year included a reversal of a valuation allowance as an $11.2 million reduction of 2002 income tax expense. Year-end 2003 provides tax expense at a rate of 37%.

The Company 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 of taxes.

Comparison of 2002 to 2001

The operating and financial enhancement of the Company continued in 2002 resulting in a transition year. While net income was higher in 2002 than in 2001, this increase was primarily due to an asset impairment taken in 2001. Production volume was down slightly in 2002 and both oil and gas prices were below 2001 levels. Various expense categories, including general and administrative expenses, were higher in 2002 as the Company continued to place greater emphasis on internally generated growth through development and exploration as opposed to primary reliance upon acquisitions. Generally, growth through acquisitions requires higher general and administrative expense after the acquired production volumes are evident while internal growth through drilling activities require higher general and administrative expenses before incremental production volumes are evident. The key personnel changes and additions made in 2002, combined with higher expenditures for acreage and seismic, is expected to bring about higher reserves and production, at lower finding costs, in the future.

Net income in 2002 totaled $25.8 million compared to $17.7 million in 2001. A $3.1 million gain on retirement of securities was realized in 2002 versus $4.0 million in 2001. Production decreased 2% to 150.1 Mmcfe per day due to lower production in the Gulf Coast region. Revenues of $190.9 million were $17.9 million lower than 2001 due to the production decline and a 7% decrease in average prices to $3.49 per mcfe. The average prices received for oil decreased 13% to $22.25 per barrel and for gas decreased 4% to $3.50 per mcf. Production expenses decreased $3.0 million to $31.9 million as a result of reduced workover costs in the Gulf Coast. Operating cost per mcfe produced (excluding production and ad valorem taxes) averaged $0.58 in 2002 versus $0.63 in 2001.

Transportation and gathering revenues were approximately the same as 2001 at $3.5 million. IPF s $3.8 million of revenues declined 43% from 2001. IPF records income on payments received on transactions that do not have a valuation allowance. On accounts with a valuation allowance, IPF reduces the carrying value of the receivable. Due to a declining portfolio balance in 2001, less income was recorded from payments received. Due to a significantly lower portfolio balance in 2002, less income was again recorded. During 2001, IPF expenses included $1.8 million of administrative costs, $1.8 million of interest and a net unfavorable adjustment of $122,000 to IPF receivables. During 2002, IPF expenses included $1.7 million of administrative costs, $937,000 of interest costs and $4.2 million was added to the valuation allowance.

Exploration expense increased 96% to $11.5 million in 2002 primarily due to higher dry hole cost, additional seismic purchases and personnel expenses. General and administrative increased 41% due to an increase in non-cash mark-to-market deferred compensation expense ($3.4 million), additional personnel costs ($1.4 million) and higher insurance and consulting costs ($550,000) offset by lower bad debt expenses. The average number of general and administrative personnel increased 12% between 2001 and 2002.

Other revenue decreased from income of $490,000 in 2001 to a loss of $2.9 million in 2002. The 2002 period included a $2.7 million ineffective loss and $1.2 million write-down of marketable securities, offset by a $715,000 recovery on an arbitration. Interest expense decreased 28% to $23.2 million primarily as a result of lower debt balances and falling interest rates. The 2001 period included $2.3 million of ineffective hedging gains and a $689,000 gain on asset sales, partially offset by a $1.7 million write-down of marketable securities and a $1.4 million bad debt expense related to Enron commodity hedges. Average debt outstanding on the Senior Credit Facility was $105.3 million and $90.5 million for 2002 and 2001, respectively, and the average interest rates were 3.4% and 6.4%, respectively.

Depletion, depreciation and amortization decreased 1% to $76.8 million as a result of lower production. The DD&A rate per mcfe in 2002 was $1.40, a $0.01 increase from 2001. The DD&A rate is determined based on year-end reserves (based on NYMEX futures prices averaging $4.11 per mcf and $23.36 per barrel) and the net book value associated with them and to a lesser extent, depreciation on other assets owned. The DD&A rate in the fourth quarter of 2002 was $1.44 per mcfe, reflecting year-end 2002 reserves. The Company recorded a $31.1 million provision for impairment on acreage and proved properties at year-end 2001 due to performance declines in the reserves and reductions in the value of various properties. No impairment was recorded in 2002.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET-RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about the Company s 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 the Company views and manages its ongoing market-risk exposures. All of the Company s market-risk sensitive instruments were entered into for purposes other than trading. All accounts of the Company are US dollar denominated.

Commodity Price Risk

The Company s 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.

The Company periodically enters hedging arrangements with respect to its oil and gas production. Hedging is intended to reduce the impact of oil and gas price fluctuations. The majority of hedges are swaps where the Company receives a fixed price for its production and pays 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 2001, gains or losses on open contracts are recorded either in current period income or other comprehensive income (OCI). The gains and losses realized as a result of hedging are substantially offset in the cash market when the commodity is delivered. Ineffective gains and losses are recognized in earnings in other revenue. The Company does not hold or issue derivative instruments for trading purposes.

As of December 31, 2003 the Company had oil and gas hedges in place covering 52.6 billion cubic feet of gas, 1.4 million barrels of oil and 0.7 million barrels of NGLs. These contracts expire monthly through December of 2006. The fair value, represented by the estimated amount that would be realized upon immediate liquidation as of December 31, 2003 approximated a net pretax loss of $70.6 million.

Gains or losses realized on hedging transactions are determined monthly based upon the difference between contract price received by the Company for the sale of its 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 2001, there was a net pretax realized loss associated with the hedges of $6.2 million followed by a gain of $17.8 million in 2002. A 2003 pretax loss realized of $60.4 million was recorded relating to the Company s hedges. Losses due to commodity hedge ineffectiveness are recognized in earnings in other revenues. The ineffective portion of hedges recorded was a gain of $2.4 million in 2001 and losses of $2.7 million in 2002 and $1.2 million in 2003.

In 2003, a 10% reduction in oil and gas prices, excluding amounts fixed through hedging transactions, would have reduced revenue by $28.6 million. If oil and gas futures prices at December 31, 2003 had declined by 10%, the unrealized hedging loss at that date would have decreased $35.9 million.

Interest Rate Risk

At December 31, 2003, the Company had $358.2 million of debt outstanding. Of this amount, $110.0 million bears interest at fixed rates averaging 7.2%. Senior debt and non-recourse debt totaling $248.2 million bears interest at floating rates, excluding interest rate swaps, which averaged 3.1% at that date. At December 31, 2003, Great Lakes had interest rate swap agreements totaling $110.0 million, 50% of which is consolidated by Range. These swaps consist of two agreements totaling $45.0 million at 7.1% which expire in May 2004, two agreements totaling $20.0 million at 2.3% which expire in December 2004, 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, 2003, the 30-day LIBOR rate was 1.1%. A 1% increase in short-term interest rates on the floating-rate debt outstanding (net of amounts fixed through hedging transactions) at December 31, 2003 would cost the Company approximately $1.9 million in additional annual interest, net of swaps.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Reference is made to the Index to Financial Statements on page 54 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

As more fully disclosed in our Form 8-K filed by the Company on July 15, 2002, the Company dismissed its auditors Arthur Anderson LLP and appointed KPMG LLP during 2002. In addition, as more fully disclosed in our Form 8-K filed by the Company on April 2, 2003, the Company dismissed its auditor, KPMG LLP and appointed Ernst and Young LLP. There were no disagreements with either of our prior accounting firms prior to their dismissal.

ITEM 9A. CONTROLS AND PROCEDURES

As of the end of the period covered by this report, the Company carried out an evaluation, under the supervision and with the participation of management, including its Chief Executive Officer and Chief Financial Officer, of the effectiveness of the Company s disclosure controls and procedures (as defined in 13a-15(e) of the Securities Exchange Act of 1934 (the Exchange Act)). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company s disclosure controls and procedures are effective in timely alerting them to material information relating to the Company (including its consolidated subsidiaries) required to be included in this report. There were no changes in the Company s internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the Company s last fiscal quarter that have materially affected or are reasonably likely to materially affect the Company s internal control over financial reporting.

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 2003 annual stockholders meeting. Officers are appointed by the Board.

	Age	Office Held Since	Position
Charles L. Blackburn	76	2003	Chairman of the Board
John H. Pinkerton	49	1990	President, Chief Executive Officer and Director
Robert E. Aikman	72	1990	Director
Anthony V. Dub	54	1995	Director
V. Richard Eales	67	2001	Director
Allen Finkelson	57	1994	Director
Jonathan S. Linker	55	2002	Director
Jeffrey L. Ventura	46	2003	Executive Vice President Chief Operating Officer
Roger S. Manny	46	2003	Senior Vice President and Chief Financial Officer
Herbert A. Newhouse	59	1998	Senior Vice President Gulf Coast
Chad L. Stephens	48	1990	Senior Vice President Corporate Development
Rodney L. Waller	54	1999	Senior Vice President and Corporate Secretary

Charles L. Blackburn, was elected as a director in April 2003 and appointed as the non-executive Chairman of the Board. Mr. Blackburn has been retired since 1995. Mr. Blackburn has more than 50 years experience in oil and gas exploration and production serving in several senior 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. Prior thereto, he had served as President of Diamond Shamrock s exploration and production subsidiary. From 1952 through 1986, Mr. Blackburn was with Shell Oil Company, serving as its Executive Vice President and Director of 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 is a director of Sepradyne, an environmental cleanup company, and 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.

John H. Pinkerton, President, Chief Executive Officer and a director, became a director in 1988. He joined the Company, 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 & Co. 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.

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 is also 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.

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

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year career at CSFB including the Investment Banking Department. Mr. Dub is also Vice Chairman and a director of Capital IQ, Inc (CIQ). CIQ is the leader in helping organizations capitalize on synergistic integration of market intelligence, institutional knowledge and relationships; it 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.

Allen Finkelson became a director in 1994. Mr. Finkelson has been a partner at Cravath, Swaine & Moore 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 in 1971. Mr. Finkelson earned a Bachelor of Arts from St. Lawrence University and a J.D. from Columbia University School of Law.

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.

Jonathan S. Linker became a director in 2002. Mr. Linker previously served as a director of the Company 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 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.

Jeffrey L. Ventura, Executive Vice President Chief Operating Officer, joined the Company 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 the Pennsylvania State University.

Roger S. Manny, Senior Vice President and Chief Financial Officer, joined the Company 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 the Company in 1998. Mr. Newhouse had held the position of Senior Vice President - Gulf Coast since joining the Company. 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 the Company 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 the Company in 1999. Since joining the Company, 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 received a Bachelor of Arts degree in Accounting from Harding University.

Code of Ethics. The Company has adopted a Code of Ethics that applies to the Company s principal executive officers, principal financial officer, principal accounting officer or controller, or persons performing similar functions. The Company has filed a copy of this Code of Ethics as Exhibit 14.1 to this Form 10-K.

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 of the Governance and Nominating Committee are Messrs. Aikman, Finkelson and Linker. All of the members of the governance and nominating committee have been deemed independent by the Board in accordance with SEC 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, 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 Securities and Exchange Commission. All of the audit committee members have been deemed independent by the Board in accordance with SEC regulations.

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. This Committee also considers candidates for officer positions. The members of the Compensation Committee are Messrs. Aikman, Blackburn and Finkelson. All of the compensation committee members have been deemed independent by the Board in accordance with SEC 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, 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 the Company s 2004 Proxy Statement.

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 the Company s 2004 Proxy Statement.

	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[(a)(b)]	3,831,135	$ 5.00	5,107,437

(a) Although the Company does not maintain a formal plan, common stock is issued to officers and key employees in lieu of cash for bonuses and company matches under the Company s 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 certain named employees are disclosed in the Company s proxy statements.

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

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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 the Company s 2004 Proxy Statement.

ITEM 16(a). BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Information with respect to Section 16(a) Beneficial Ownership Reporting Compliance is incorporated herein by reference to the Company s 2004 Proxy Statement.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENTS, FINANCIAL STATEMENT 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 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 (the Company) 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 the Company s Form 8-K (File No. 001-12209) as filed with the Securities and Exchange Commission (the SEC) on January 5, 2004)
3.1.1	Restated Certificate of Incorporation of Lomak Petroleum, Inc. (Lomak) (incorporated by reference to Exhibit 3.1.1 to the Company s Form S-4 (File No. 33-108516)) as filed with the SEC on

	September 4, 2003)
3.1.2	Certificate of Amendment to the Certificate of Incorporation dated June 20, 1997 (incorporated by reference to Exhibit 3.1.11 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
3.1.3	Certificate of Amendment to the Certificate of Incorporation of Lomak dated August 25, 1998 (incorporated by reference to Exhibit 3.1 to the Company s Form S-8 (File No. 333-62439) as filed with the SEC on August 28, 1998)
3.1.4	Certificate of Amendment to the Certificate of Incorporation of the Company dated May 24, 2000 (incorporated by reference to Exhibit 3.1.12 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on May 7, 2003)
3.1.5	Certificate of Correction to Certificate of Amendment to the Certificate of Incorporation (incorporated by reference to Exhibit 3.1.5 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on November 5, 2003)
3.1.6	Certificate of Correction to Certificate of Amendment to the Certificate of Incorporation (incorporated by reference to Exhibit 3.1.6 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on November 5, 2003)
3.2**	Amended and Restated By-laws of the Company dated December 5, 2003
4.1.1	Form of 6% Convertible Subordinated Debentures due 2007 (contained as an exhibit to Exhibit 4.1.2 hereto)

Exhibit No.	Description
4.1.2	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)
4.1.3	Form of 7-3/8% Senior Subordinated Notes due 2013 (contained as an exhibit 4.1.4 hereto)
4.1.4	Indenture dated July 21, 2003 by and among the Company, 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 the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
4.1.5	Registration Rights Agreement dated July 21, 2003 by and between the Company and UBS Securities LLC, Banc One Capital Markets, Inc., Credit Lyonnais Securities (USA), Inc., and McDonald Investments Inc., (incorporated by reference to Exhibit 4.4.3 to the Company s 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 the Company (incorporated by reference to Exhibit 4.2 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on November 5, 2003)
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)
10.2.1	Application Service Provider and Outsourcing Agreement dated June 1, 2000 by and between Applied Terravision Systems, Inc. and the Company (incorporated by reference to Exhibit 10.4 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on August 8, 2000)
10.2.2	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 the Company (incorporated by reference to Exhibit 10.1 to the Company s 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 the Company and Thomas J. Edelman (incorporated by reference to Exhibit 10.2 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
10.4.1	Amended and Restated Credit Agreement dated May 2, 2002 by and among the Company, Bank One, NA, the Lenders (as defined therein), Bank One, NA, as Administrative Agent, Fleet National Bank, as Co-Documentation Agent, Fortis Capital Corp., as Co-Documentation Agent, JPMorgan Chase Bank, as Co-Syndication Agent, Credit Lyonnais, New York Branch, as Co-Syndication Agent, Banc One Capital Markets, Inc., as Joint Lead Arranger and Joint Bookrunner, and JPMorgan Securities, Inc., as Joint Lead Arranger and Joint Bookrunner (incorporated by reference to Exhibit 10.1 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on May 7, 2002)

10.4.2	First Amendment to Amended and Restated Credit Agreement dated December 27, 2002 by and among the Company, Bank One, NA, the Lenders (as defined therein), Bank One, NA, as Administrative Agent, Fleet National Bank, as Co-Documentation Agent, Fortis Capital Corp., as Co-Documentation Agent, JPMorgan Chase Bank, as Co-Syndication Agent, Credit Lyonnais, New York Branch, as Co-Syndication Agent, Banc One Capital Markets, Inc., as Joint Lead Arranger and Joint Bookrunner, and JPMorgan Chase Bank, as Joint Lead Arranger and Joint Bookrunner (incorporated by reference to Exhibit 10.15.6 to the Company s Form 10-K (File No. 001-12209) as filed with the SEC on March 5, 2003)
10.4.3	Second Amendment to Amended and Restated Credit Agreement dated January 24, 2003 by and among the Company, Bank One, NA, the Lenders (as defined therein), Bank One, NA, as Administrative Agent, Fleet National Bank, as Co-Documentation Agent, Fortis Capital Corp., as Co-Documentation Agent, JPMorgan Chase Bank, as Co-Syndication Agent, Credit Lyonnais, New York Branch, as Co-Syndication Agent, Banc One Capital Markets, Inc., as Joint Lead Arranger and Joint-Bookrunner, and JPMorgan Chase Bank, as Joint Lead Arranger and Joint Bookrunner (incorporated by reference to Exhibit 10.1 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on May 7, 2003)
10.4.4	Third Amendment to Amended and Restated Credit Agreement dated April 1, 2003 by and among the Company, Bank One, NA, the Lenders (as defined therein), Bank One, NA, as Administrative Agent, Fleet National Bank, as Co-Documentation Agent, Fortis Capital Corp., as Co-Documentation Agent, JPMorgan Chase Bank, as Co-Syndication Agent, Credit Lyonnais, New York Branch, as Co-Syndication Agent, Banc One Capital Markets, Inc., as Joint Lead Arranger and Joint Bookrunner, and JPMorgan Securities, Inc., as Joint Lead Arranger and Joint Bookrunner (incorporated by reference to Exhibit 10.2 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on May 7, 2003)
10.4.5	Fourth Amendment to Amended and Restated Credit Agreement dated July 15, 2003 by and among the Company, Bank One, NA, the Lenders (as defined therein), Bank One, NA, as Administrative Agent, Fleet National Bank, as Co-Documentation Agent, Fortis Capital Corp., as Co-Documentation Agent,

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Exhibit No.	Description
	JPMorgan Chase Bank, as Co-Syndication Agent, Credit Lyonnais, New York Branch, as Co-Syndication Agent, Banc One Capital Markets, Inc., as Joint Lead Arranger and Joint Bookrunner, and JPMorgan Securities, Inc, as Joint Lead Arranger and Joint Bookrunner (incorporated by reference to Exhibit 10.6.5 to the Company s Form S-4 (File No. 333-108516) as filed with the SEC on September 4, 2003)
10.4.6	Fifth Amendment to Amended and Restated Credit Agreement dated September 4, 2003 by and among the Company, Bank One, NA, the lenders (as defined therein), Bank One, NA, as Administrative Agent, Fleet National Bank, as Co-Documentation Agent, Fortis Capital Corp., as Co-Documentation Agent, JPMorgan Chase Bank, as Co-Syndication Agent, Credit Lyonnais, New York Branch, as Co-Syndication Agent, Banc One Capital Markets, Inc., as Joint Lead Arranger and Joint Bookrunner, and JPMorgan Securities, Inc., as Joint Lead Arranger and Joint Bookrunner (incorporated by reference to Exhibit 10.1.2 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on November 5, 2003)
10.4.7**	Sixth Amendment to the Amended and Restated Credit Agreement dated October 1, 2003 by and among the Company, Bank One, NA, the Lenders (as defined therein), Bank One, NA as Administrative Agent, Fleet National Bank, as Co-Documentation Agent, Fortis Capital Corp., as Co-Documentation Agent, JP Morgan Chase Bank, as Co-Syndication Agent, Credit Lyonnais New York Branch, as Co-Syndication Agent, Banc One Capital Markets, Inc. as Joint Lead Arranger and Joint Bookrunner and JPMorgan Securities, Inc., as Joint Lead Arranger and Joint Bookrunner
10.4.8**	Seventh Amendment to the Amended and Restated Credit Agreement dated December 23, 2003 by and among the Company, Bank One, N.A., the Lenders (as defined therein), Bank One, NA as Administrative Agent, Fleet National Bank, as Co-Documentation Agent, Fortis Capital Corp., as Co-Documentation Agent, JP Morgan Chase Bank, as Co-Syndication Agent, Credit Lyonnais New York Branch, as Co-Syndication Agent, Bank One Capital Markets, Inc., as Joint Lead Arranger and Joint Bookrunner and JPMorgan Securities, Inc., as Joint Lead Arranger and Joint Bookrunner
10.5.1	Restated Credit Agreement dated May 3, 2002 by and among Great Lakes Energy Partners, L.L.C. (Great Lakes), Bank One, NA, JPMorgan Chase Bank, The Bank of Nova Scotia, Bank of Scotland, Credit Lyonnais, New York Branch, Fortis Capital Corp., The Frost National Bank, Union Bank of California, N.A., each Lender (as defined therein), Bank One, NA, as Administrative Agent, JPMorgan Chase Bank, as Syndication Agent, Credit Lyonnais, New York Branch, as Documentation Agent and The Bank of Nova Scotia, as Managing Agent (incorporated by reference to Exhibit 10.4.1 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
10.5.2	First Amendment to Restated Credit Agreement dated April 1, 2003 by and among Great Lakes, Bank One, NA, JPMorgan Chase Bank, The Bank of Nova Scotia, Bank of Scotland, Credit Lyonnais, New York Branch, Fortis Capital Corp., The Frost National Bank, Union Bank of California, N.A., Comerica Bank-Texas, Natexis Banques Populaires, each Lender (as defined therein), Bank One, NA, as Administrative Agent, JPMorgan Chase Bank, as Syndication Agent, Credit Lyonnais, New York Branch, as Co-Documentation Agent, The Bank of Nova Scotia, as

	Co-Documentation Agent, Banc One Capital Markets, Inc., as Joint Lead Arranger and Bookrunner, and JPMorgan Securities, Inc., as Joint Lead Arranger and Bookrunner (incorporated by reference to Exhibit 10.4.2 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
10.6	Amended and Restated Range Resources Corporation Deferred Compensation Plan for Directors and Select Employees effective September 1, 2000 (incorporated by reference to Exhibit 10.15 to the Company s Form 10-K (File No. 001-12209) as filed with the SEC on March 6, 2001)
10.7.1	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)
10.7.2	Amendment to the Lomak 1989 Stock Option Plan, as amended (incorporated 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)
10.7.3	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)
10.8.1	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)
10.8.2	First Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated June 8, 1995 (incorporated by reference to Exhibit 4.6 to the Company s Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.8.3	Second Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated August 21, 1996 (incorporated by reference to Exhibit 4.7 to the Company s Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.8.4	Third Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated June 1, 1999 (incorporated by reference to Exhibit 4.8 to the Company s Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)

Exhibit No.	Description
10.8.5	Fourth Amendment to the Company s 1994 Outside Directors Stock Option Plan dated May 24, 2000 (incorporated by reference to Exhibit 4.9 to the Company s Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.9	Second Amended and Restated 1996 Stock Purchase and Option Plan for Key Employees of Domain Energy Corporation and Affiliates (incorporated by reference to Exhibit 4.1 to the Company s Form S-8 (File No. 333-62439) as filed with the SEC on August 28, 1998)
10.10.1	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)
10.10.2	First Amendment to the Lomak 1997 Stock Purchase Plan dated May 26, 1999 (incorporated by reference to Exhibit 4.2 to the Company s Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.10.3	Second Amendment to the Lomak 1997 Stock Purchase Plan dated September 28, 1999 (incorporated by reference to Exhibit 4.3 to the Company s Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.10.4	Third Amendment to the Company s 1997 Stock Purchase Plan dated May 24, 2000 (incorporated by reference to Exhibit 4.4 to the Company s Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.10.5	Fourth Amendment to the Company s 1997 Stock Purchase Plan dated May 24, 2001 (incorporated by reference to Exhibit 4.7 to the Company s Form S-8 (File No. 333-63764) as filed with the SEC on June 25, 2001)
10.11	Amended and Restated 1999 Stock Option Plan (as amended May 21, 2003) (incorporated by reference to Exhibit 4.1 to the Company s Form S-8 (File No. 333-105895) as filed with the SEC on June 6, 2003)
10.12	Range Resources Corporation 401(k) Plan (incorporated by reference to Exhibit 10.14 to the Company s Form S-4 (File No. 333-108516) as filed with the SEC on September 4, 2003)
10.13	Range Resources Corporation Amended and Restated Change in Control Plan dated September 15, 1998 (incorporated by reference to Exhibit 10.15 to the Company s Form S-4 (File No. 333-108516, as filed with the SEC on September 4, 2003)
14.1**	Code of Ethics
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 the Company Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer of the Company Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification by the President and Chief Executive Officer of the Company Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification by the Chief Financial Officer of the Company Pursuant to 18 U.S.C. Section 350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99**	Audit Committee Charter

*Filed herewith. **Filed previously.

(b) Reports on Form 8-K.

On October 3, 2003, the Company filed a current report on Form 8-K, pursuant to Item 9 of Form 8-K, furnishing the Company s press release announcing its debt information as of September 30, 2003.

On October 21, 2003, the Company filed a current report on Form 8-K, pursuant to Item 9 of Form 8-K, furnishing the Company s press release announcing third quarter of 2003 production volumes, borrowing base status and other operational information.

On November 6, 2003, the Company filed a current report on Form 8-K, pursuant to Item 9 of Form 8-K, furnishing the Company s press release announcing its third quarter of 2003 results.

(c) Exhibits required to be filed pursuant to Item 601 of Regulation S-K are contained in Exhibits listed in response to Item 15 (a)3, and are incorporated herein by reference

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

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SIGNATURES

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

Dated: April 6, 2004

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	April 6, 2004
/s/ John H. Pinkerton John H. Pinkerton	President, Chief Executive Officer and Director	April 6, 2004
/s/ Roger S. Manny Roger S. Manny	Chief Financial and Accounting Officer	April 6, 2004
/s/ Robert E. Aikman Robert E. Aikman	Director	April 6, 2004
/s/ Anthony V. Dub Anthony V. Dub	Director	April 6, 2004
/s/ V. Richard Eales V. Richard Eales	Director	April 6, 2004
/s/ Allen Finkelson Allen Finkelson	Director	April 6, 2004
/s/ Jonathan S. Linker	Director	April 6, 2004

Jonathan S. Linker

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GLOSSARY

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

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

Senior credit facility. Range Resource s $225 million revolving bank facility.

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 high 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.

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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 producing reserves. Proved reserves that can be expected to be recovered from currently producing zones under the continuation of present operating methods.

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 from known reservoirs under existing economic 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 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.

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 Commission s rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

term 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 the Company participates through Independent Producer Finance 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.

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RANGE RESOURCES CORPORATION

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULES

(Item 15[a], [d])

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REPORT OF INDEPENDENT AUDITORS

To The Board of Directors and Stockholders
Range Resources Corporation:

We have audited the accompanying consolidated balance sheet of Range Resources Corporation (and subsidiaries) as of December 31, 2003, and the related consolidated statements of operations, stockholders equity, comprehensive income (loss) and cash flows for the year ended December 31, 2003. 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 auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, based on our audit, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Range Resources Corporation (and subsidiaries) at December 31, 2003, and the consolidated results of their operations and their cash flows for the year ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 4, the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, on January 1, 2003.

ERNST & YOUNG
LLP

Fort Worth, Texas
February 26, 2004

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REPORT OF INDEPENDENT AUDITORS

To The Board of Directors and Stockholders
Range Resources Corporation:

We have audited the accompanying consolidated balance sheet of Range Resources Corporation as of December 31, 2002, and the related consolidated statements of operations, stockholders equity, comprehensive income (loss) and cash flows for each of the years in the two-year period 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 audits. We did not audit the financial statements of Great Lakes Energy Partners L.L.C., a fifty percent owned consolidated subsidiary (see Note 2) as of December 31, 2002 and for the year then ended, which statements reflect total assets constituting 32 percent and 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 audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the report of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Range Resources Corporation as of December 31, 2002, and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, effective January 1, 2001, the Company changed their method of accounting for derivative financial instruments and hedging activities.

KPMG LLP

Dallas, Texas
March 4, 2003

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REPORT OF INDEPENDENT AUDITORS

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

We have audited the consolidated balance sheet of Great Lakes Energy Partners, L.L.C. and subsidiaries, (A Delaware limited liability company) (the Company) as of December 31, 2002, and the related consolidated statements of income, members equity, accumulated other comprehensive income (loss) and comprehensive income (loss) and cash flows for the year then ended (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 auditing standards generally accepted in the 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 financial position of Great Lakes Energy Partners, L.L.C. and subsidiaries as of December 31, 2002, and the consolidated results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States.

ERNST & YOUNG
LLP

Pittsburgh, Pennsylvania
January 31, 2003

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RANGE RESOURCES CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands)

	December 31,	
	2003	2002
Assets		
Current assets		
Cash and equivalents	$ 631	$ 1,334
Accounts receivable, net of allowance, for doubtful accounts of $1,042 and $961 as of December 31, 2003 and 2002, respectively	37,745	26,832
IPF receivables, net (Note 2)	4,400	6,100
Unrealized derivative gain (Note 7)	116	4
Deferred tax asset	19,871	13,265
Inventory and other	3,329	3,084
	66,092	50,619
IPF receivables, net (Note 2)	8,193	18,351
Unrealized derivative gain (Note 7)	250	13
Oil and gas properties, successful efforts method (Note 16)	1,362,811	1,154,549
Accumulated depletion	(639,429)	(590,143)
	723,382	564,406
Transportation and field assets (Note 2)	41,218	34,143
Accumulated depreciation and amortization	(18,912)	(16,071)
	22,306	18,072
Deferred tax asset, net (Note 13)		2,520
Other (Note 2)	9,868	4,503
	$ 830,091	$ 658,484

Liabilities and Stockholders Equity

Current liabilities		
Accounts payable	$ 32,105	$ 27,044
Asset retirement obligation (Note 4)	5,814	
Accrued liabilities	10,768	9,678
Accrued interest	3,932	4,449
Unrealized derivative loss (Note 7)	54,345	26,035
	106,964	67,206
Senior debt (Note 6)	178,200	115,800
Non-recourse debt (Note 6)	70,000	76,500
Subordinated notes (Note 6)	109,980	90,901
Trust preferred manditorily redeemable securities of subsidiary (Note 6)		84,840
Deferred tax, net (Note 13)	10,843	
Unrealized derivative loss (Note 7)	17,027	9,079
Deferred compensation liability (Note 11)	16,981	8,049
Asset retirement obligation (Note 4)	46,030	
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 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, 56,409,791 and 54,991,611 issued and outstanding, respectively	564	550
Capital in excess of par value	399,662	391,082
Retained earnings (deficit)	(124,011)	(158,059)
Stock held by employee benefit trust, 1,671,386 and 1,324,537 shares, respectively, at cost (Note 11)	(8,441)	(6,188)
Deferred compensation expense	(856)	(125)
Accumulated other comprehensive income (loss) (Note 2)	(42,852)	(21,151)
	274,066	206,109
	$ 830,091	$ 658,484

See accompanying notes.

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RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

	Year Ended December 31,		
	2003	**2002**	**2001**
Revenues			
Oil and gas sales	$226,402	$190,954	$208,854
Transportation and gathering	3,509	3,495	3,435
IPF income (Note 2)	1,547	3,789	6,646
Gain on retirement of securities (Note 18)	18,991	3,098	3,951
Other	(1,252)	(2,900)	490
	249,197	198,436	223,376
Expenses			
Direct operating	36,423	31,869	34,884
Production and ad valorem taxes	12,894	8,574	8,546
IPF	2,965	6,847	3,761
Exploration	13,946	11,525	5,879
General and administrative (Note 11)	24,377	17,240	12,212
Interest expense and dividends on trust preferred	22,165	23,153	32,179
Debt conversion expense	465		
Depletion, depreciation and amortization	86,549	76,820	77,573
Provision for impairment (Note 2)			31,085
	199,784	176,028	206,119
Income before income taxes and accounting change	49,413	22,408	17,257
Income tax (benefit) (Note 13)			
Current	170	(4)	(406)
Deferred	18,319	(3,354)	
	18,489	(3,358)	(406)
Income before cumulative effect of change in accounting principle	30,924	25,766	17,663
Cumulative effect of change in accounting principle, net of	4,491		

taxes (Note 4)			
Net income	35,415	25,766	17,663
Gain on retirement of preferred stock			556
Preferred dividends	(803)		(10)
Net income available to common shareholders	$ 34,612	$ 25,766	$ 18,209
Earnings per common share (Note 14)			
Net income available to common shareholders	$ 0.56	$ 0.49	$ 0.36
Cumulative effect of change in accounting principle	0.08		
Net income per common share	$ 0.64	$ 0.49	$ 0.36
Earnings per common share assuming dilution	$ 0.53	$ 0.47	$ 0.36
Cumulative effect of change in accounting principle	0.08		
Net income per common share assuming dilution	$ 0.61	$ 0.47	$ 0.36

See accompanying notes.

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RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Year Ended December 31,		
	2003	**2002**	**2001**
Cash flow from operations			
Net income	$ 35,415	$ 25,766	$ 17,663
Adjustments to reconcile net income to net cash provided by operations:			
Deferred income tax expense (benefit)	18,319	(3,353)	
Cumulative effect of change in accounting principle, net	(4,491)		
Depletion, depreciation and amortization	86,549	76,820	77,573
Exploration expenses	3,576	5,280	974
Write-down of marketable securities		1,220	1,715
Unrealized hedging (gains) losses	679	3,005	(1,019)
Provision for impairment			31,085
Allowance for bad debts	399	150	2,040
Allowance for IPF receivables	1,739	4,240	122
Amortization of deferred issuance costs and discount	1,207	899	1,961
Debt conversion and extinguishment expense	465		
Deferred compensation adjustments	6,867	2,506	(1,234)
Gain on retirement of securities and other	(19,634)	(3,125)	(4,004)
(Gain) loss on sale of assets and other	217	(161)	(689)
Changes in working capital			
Accounts receivable	(11,530)	(2,685)	5,540
Inventory and other	501	(893)	226
Accounts payable	2,982	3,364	548
Accrued liabilities and other	2,217	1,439	(1,929)
Net cash provided by operations	125,477	114,472	130,572
Cash flow from investing			
Oil and gas properties	(91,985)	(92,556)	(78,517)
Field service assets	(2,618)	(2,815)	(2,331)
Acquisitions	(103,869)	(21,790)	(9,491)
IPF investments	(1,818)	(5,106)	(11,629)
IPF repayments	12,126	17,321	19,034
Asset sales	529	996	3,771
Net cash used in investing	(187,635)	(103,950)	(79,163)

Cash flow from financing			
Borrowings on credit facilities	318,700	173,400	210,600
Repayments on credit facilities	(262,800)	(174,900)	(219,700)
Issuance of senior notes	98,272		
Other debt repayment	(92,508)	(11,087)	(42,946)
Preferred dividends	(803)		(10)
Debt issuance costs	(2,183)	(985)	
Issuance of common stock	2,777	1,004	1,488
Repurchase of preferred stock			(73)
Net cash provided by (used in) financing	61,455	(12,568)	(50,641)
Increase (decrease) in cash and cash equivalents	(703)	(2,046)	768
Cash and equivalents, beginning of year	1,334	3,380	2,612
Cash and equivalents, end of year	$ 631	$ 1,334	$ 3,380

See accompanying notes.

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RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(In thousands)

	Preferred Stock		Common Stock						Accumulated	
	Shares	Par Value	Shares	Par Value	Capital in Excess of Par Value	Retained Earnings (Deficit)	Stock held by Employee Benefit Trust	Deferred Compensation Expense	Other Comprehensive Income	Total
Balance December 31, 2000	**220**	**$ 220**	**49,188**	**$492**	**$364,925**	**$(201,478)**	**$(3,496)**	**$ (80)**	**$ (639)**	**$159,944**
Preferred dividends ($1.97 per share)						(10)				**(10)**
Issuance of common			858	8	4,030		(1,394)	(59)		**2,585**
Conversion of securities	(220)	(220)	2,597	26	9,471					**9,277**
Other comprehensive income									46,162	**46,162**
Net income						17,663				**17,663**
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**

See accompanying notes.

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RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In thousands)

	Year Ended December 31,		
	2003	**2002**	**2001**
Net income	$ 35,415	$ 25,766	$ 17,663
Other comprehensive income (loss):			
Net deferred hedge gains (losses), net of tax:			
Transition adjustment			(72,100)
Net hedging gains (losses) included in net income	(38,069)	11,563	(6,194)
Change in unrealized deferred hedging gains (losses)	16,181	(77,800)	122,853
Defaulted hedge contracts		(437)	672
Net unrealized gains (losses) on available for sale securities	187		931
Comprehensive income (loss)	$ 13,714	$(40,908)	$ 63,825

See accompanying notes.

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RANGE RESOURCES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) ORGANIZATION AND NATURE OF BUSINESS

Range Resources Corporation (the Company or Range) is engaged in the exploration, development and acquisition of oil and gas properties primarily in the Southwestern, Gulf Coast and Appalachian regions of the United States. The Company seeks to increase its reserves and production primarily through drilling and complementary acquisitions. The Company holds its Appalachian oil and gas assets through a 50% owned joint venture, Great Lakes Energy Partners L.L.C. (Great Lakes). 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

The accompanying consolidated financial statements include the accounts of the Company, wholly-owned subsidiaries and a 50% pro rata share of the assets, liabilities, income and expenses of Great Lakes. Liquid investments with original maturities of 90 days or less are considered cash equivalents. The Company has no off-balance sheet assets or liabilities other than those referred to in the consolidated financial statements.

Revenue Recognition

The Company recognizes revenues from the sale of products and services in the period delivered. Payments received at IPF relating to return on investment are recognized as income with the remaining receipts reducing receivables. Although receivables are concentrated in the oil industry, the Company does not view this as unusual credit risk. The Company provides for allowance for doubtful accounts for specific receivables judged unlikely to be collected based on the age of the receivable, the Company s experience with the debtor, potential offsets to the amount owed and economic conditions. IPF s receivables are from small independent operators who usually have limited access to capital and the assets which underlie the receivables lack diversification. A decrease in oil and gas prices could cause an increase in IPF s valuation allowances and a corresponding decrease in income. At December 31, 2003 and 2002, IPF had valuation allowances of $9.6 million and $12.6 million, respectively. The Company had other allowances for doubtful accounts relating to exploration and production of $1.0 million and $961,000 at December 31, 2003 and 2002, respectively.

Marketable Securities

Holdings of equity securities qualify as available-for-sale and are recorded at fair value. The Company owns approximately 17% of a small publicly traded independent exploration and production company. Based on its analysis of the securities, the Company determined that the investment had no determinable value at June 30, 2002 and the book value of the investment was fully reserved.

Independent Producer Finance

IPF acquires dollar denominated overriding royalties in oil and gas properties from small producers. 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. Receivables classified as current represent the return of capital expected to be received within 12 months. All receivables are evaluated quarterly and provisions for uncollectible amounts are established based on the Company s valuation of its royalty interest in the oil and gas properties. Interest is not recognized where the valuation indicates that the entire principal will not be recovered. As of December 31, 2003, receivables for which no valuation allowance existed totaled $6.8 million and the weighted average rate of return on that balance was 17%. During 2003, 2002 and 2001, IPF expenses were comprised of $1.0 million, $1.7 million and $1.8 million of general and administrative costs and $207,000, $937,000 and $1.8 million of interest, respectively. In 2003, 2002 and 2001, IPF recorded a $1.7 million, $4.2 million and $2.0 million increase in the valuation allowance, respectively. The valuation allowance at December 31, 2003 and 2002 was $9.6 million and $12.6 million, respectively.

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

	2003	2002	2001
		(in thousands)	
Balance at beginning of year	$(12,640)	$(12,928)	$(10,927)
Provisions charged to IPF expenses	(3,334)	(5,317)	(4,361)
Recoveries credited to IPF expenses	1,595	1,077	2,360
Amounts written off to principal	4,771	4,528	
Balance at end of year	$ (9,608)	$(12,640)	$(12,928)

Oil and Gas Properties

The Company follows the successful efforts method of accounting. 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. Depletion is provided on the unit-of-production method. Oil and NGLs are converted to gas equivalent basis (mcfe) at the rate of six mcf per barrel. The depletion, depreciation and amortization (DD&A) rates were $1.49, $1.40 and $1.39 per mcfe in 2003, 2002 and 2001, respectively. Unproved properties had a net book value of $12.2 million, $19.0 million and $25.7 million at December 31, 2003, 2002 and 2001, respectively. Unproved properties are reviewed quarterly for impairment and reduced to fair value if required.

The Company adopted Statement of Financial Accounting Standards No. 144 Accounting for Impairment or Disposal of Long-Lived Assets (SFAS 144) on January 1, 2002 and there was no material impact on the Company. The Company s 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 in accordance with SFAS 144. 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 management s 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. Management estimates 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 and the carrying value of the assets.

The following are the proved property values impaired due to declines in gas prices in 2001, based on the analysis of estimated future cash flows (in thousands):

Year Ended December 31,	Property	Reason for Impairment	Impairment Amount
2001	Matagorda Island 519	Decline in gas price	$14,001

Offshore Other	Decline in gas price	3,302
Gulf Coast Onshore	Decline in gas price	8,542
Oceana	Decline in gas price	99
	Total	$25,944

The following acreage was impaired in 2001 for the reasons indicated (in thousands):

Year Ended December 31,	**Property**	**Reason for Impairment**	**Impairment Amount**
2001	Matagorda Island 519	Probability of drilling reduced based on current assessment of risk and cost overruns and delays	$ 1,704
	West Delta 30	Probability of drilling reduced based on current assessment of risk and cost	688
	East/West Cameron	Condemned portion of leasehold through drilling or geologic assessment	708
	Offshore Other	Probability of drilling reduced based on current assessment of risk and cost	1,216
	East Texas	Condemned portion of leasehold through drilling	825
		Total	$ 5,141

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Transportation and Field Assets

The Company s gas transportation and gathering systems are generally located in proximity to certain of its principal fields. Depreciation on these systems is provided on the straight-line method based on estimated useful lives of 10 to 15 years. The Company receives third-party income for providing certain transportation and field services which are 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.

Other Assets

The expenses of issuing debt are capitalized and included in other assets on the Company s 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, 2003, such deferred financing costs totaled $2.4 million. Other assets at December 31, 2003 include $2.4 million unamortized debt issuance costs, $1.8 million of marketable securities held in the deferred compensation plan, $578,000 of long-term deposits and a $5.1 million receivable related to an insurance claim.

Gas Imbalances

The Company uses the sales method to account for gas imbalances, recognizing revenue based on cash received rather than gas produced. Gas imbalances at December 31, 2003 and December 31, 2002 were not significant. At December 31, 2003, the Company has recorded a net liability of $385,000 for those wells where it was determined that there was insufficient reserves to retire gas imbalances.

Stock Options

The Company applies 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 its fixed plan stock options. As such, compensation expense would be 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, the Company has elected to continue to apply the intrinsic value-based method of accounting described above, and has adopted the disclosure requirements of SFAS 123, was amended by SFAS No. 148, Accounting for Stock-Based Compensation-Transition and Disclosures.

The Company has 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 2003, 2002 and 2001 consistent with the provisions of SFAS 123, the Company s net income and earnings per share would have been reduced to the pro forma amounts indicated below:

	Year Ended December 31,		
	2003	2002	2001
	(in thousands, except per share data)		
Net income, as reported	$35,415	$25,766	$17,663
	4,326	2,149	(44)

Plus: Total stock-based employee compensation cost (income) included in net income, net of tax			
Deduct: Total stock-based employee compensation determined under fair value based method, net of taxes	$ (7,193)	$ (3,069)	$ (742)
Pro forma net income	$32,548	$24,846	$16,877
Earnings per share:			
Basic-as reported	$ 0.64	$ 0.49	$ 0.36
Basic-pro forma	$ 0.58	$ 0.47	$ 0.35
Diluted-as reported	$ 0.61	$ 0.47	$ 0.36
Diluted-pro forma	$ 0.57	$ 0.46	$ 0.34

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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 assumptions used for 2003, 2002 and 2001, respectively: fair value of $5.01, $4.89 and $6.50 per share; dividend yields of $0.00 per share; expected volatility factors of 167%, 166% and 70%; risk-free interest rates of 3.2%, 4.9% and 5.0%, and an average expected life of 5 years, 9 years and 6 years.

Derivative Financial Instruments and Hedging

Beginning in 2001, Statement of Financial Accounting Standards No. 133 Accounting for Derivatives (SFAS 133) required that derivatives be recorded on the balance sheet as assets or liabilities at fair value. For derivatives qualifying as cash flow hedges, the effective portion of any changes in fair value is recognized in stockholders equity as other comprehensive income (loss) (OCI) and then reclassified to earnings when the transaction is consummated. Changes in the value of the ineffective portion of all open hedges are recognized in earnings quarterly. The Company enters into hedging agreements to reduce the impact of volatile oil and gas prices. On adopting SFAS 133 in January 2001, the Company recorded a $72.1 million net unrealized pretax hedging loss on its Consolidated Balance Sheet and an offsetting deficit in OCI. At December 31, 2003, this loss had become $70.6 million for commodity hedges with an offsetting debit in OCI of $68.5 million. The Company has realized $2.1 million of ineffectiveness relating to its commodity hedges. SFAS 133 can greatly increase volatility of earnings and stockholders equity of independent oil companies which have active hedging programs such as Range. 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. Stockholders equity is affected by the increase or decrease in OCI. Typically, when oil and gas prices increase, OCI decreases. Of the $68.5 million unrealized pretax loss at December 31, 2003, $52.0 million of losses will be reclassified to earnings over the next 12 month period and $16.5 million for the periods thereafter, if prices remain constant. Actual amounts that will be reclassified will vary as a result of changes in prices. The Company also enters into swap agreements to reduce the risk of changing interest rates. These agreements generally qualify as cash flow hedges whereby changes in the fair value of the swaps are reflected as an adjustment to OCI to the extent the swaps are effective and are recognized in income as an adjustment to interest expense in the period covered.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires management to make estimates and assumptions that affect the reported assets, liabilities, revenues and expenses, as well as disclosure of contingent assets and liabilities. Actual results could differ from those estimates. 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, evaluations 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 the Company s financial statements include the IPF and deferred tax valuation allowances and fair value of derivatives.

Recent Accounting Pronouncements

In April 2002, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 145 Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement 13 and Technical Corrections (SFAS 145). As a result, gains from early extinguishment of debt will be reported in income from continuing operations. The Company adopted the provisions of SFAS 145 as of January 1, 2003. This adoption resulted in the reclassification of extraordinary gain on sale or exchange of securities totaling $3.1 million and

$4.0 million to revenue in the twelve months ended December 31, 2002 and December 31, 2001, respectively, with no change to reported net income.

In January 2003, the FASB issued Interpretation No. 46 Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51 (the Interpretation). The Interpretation will significantly change whether entities included in its scope are consolidated by their sponsors, transferors, or investors. The Interpretation introduces a new consolidation model - the variable interest model which determines control (and consolidation) based on potential variability in gains and losses of the entity being evaluated for consolidation. These provisions apply immediately to variable interests in Variable Interest Entities (VIEs) created after January 15, 2003 and are effective in 2004, for VIEs in which the Company holds a variable interest that it acquired prior to February 1, 2003. The Company is still evaluating the impact of this new interpretation.

In May 2003, the FASB issued Statement of Financial Accounting Standards No. 150 Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity (SFAS 150). SFAS 150 established standards for classification and measurement in the statement of financial position of certain financial instruments with characteristics of both liabilities and equity. It requires classification of a financial instrument that is within its scope as a liability (or an asset in some circumstances). SFAS 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after September 15, 2003. The adoption of SFAS 150 did not have an impact on the Company s financial position or results of operations.

The FASB and representatives of the accounting staff of the SEC are engaged in discussions on the issue of whether the SFAS No. s 141 and 142, issued effective for June 30, 2001, called for mineral rights held under lease or other contractual arrangements to be classified in the balance sheet as intangible assets and accompanied by specific footnote disclosures. Historically, the Company and all other oil and gas companies have included the cost of these oil and gas leasehold interests as part of oil and gas properties. As of December 31, 2003 a total of $447 million of leasehold costs is included in net oil and gas properties. Although most of the Company s oil and gas property interests are held under oil and gas leases, this interpretation, if adopted, is not expected to have a material impact on the Company s financial position or its results of operations.

In the event this interpretation is adopted, a substantial portion of acquisition costs of oil and gas properties would be separately classified on the balance sheet as intangible assets. Some additional direct costs of other oil and gas leases acquired since that date could also be categorized as intangible under this interpretation. Results of operations would not be affected by this interpretation, if adopted, since these costs would continue to be depleted in accordance with successful efforts accounting for oil and gas companies. Another possible effect of this interpretation, if adopted, could be a change in some of the financial measurements used in financial covenants of debt instruments that focus on tangible assets. The Company does not believe that its debt covenants would be materially affected by the adoption of this accounting interpretation.

Reclassifications

Certain reclassifications have been made to the presentation of prior periods to conform with current year presentation.

(3) ACQUISITIONS

Acquisitions are accounted for as purchases, and accordingly, the results of operations are included in the Company s Statements 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. The Company purchased various properties for consideration of $100.9 million, $21.8 million and $9.5 million, during the years ended December 31, 2003, 2002 and 2001, respectively. These purchases include $90.7 million, $15.6 million and $4.2 million for proved oil and gas reserves, respectively, the remainder represents unproved acreage purchases. Purchases in 2003 also include $4.6 million related to gas gathering facilities.

On December 23, 2003, the Company purchased producing oil and gas properties covering 38,000 gross (32,000 net) acres of leases which are adjacent to the Company s Conger Field properties in West Texas. The purchase price should approximate $87.1 million after normal post closing adjustments and includes $2.1 million additional estimated costs for asset retirement obligations. The Company recorded $80.4 million to oil and gas properties, $4.6 million to transportation and field assets and facilities and $2.1 million additional asset retirement obligations as a preliminary purchase price allocation. This acquisition was funded through the existing $225.0 million secured revolving bank credit facility (the Senior Credit Facility).

(4) ASSET RETIREMENT OBLIGATION

Beginning in 2003, Statement of Financial Accounting Standards No. 143 Asset Retirement Obligations (SFAS 143) requires the Company to recognize an estimated liability for the plugging and abandonment of its oil and gas wells and associated pipelines and equipment. Previously, the Company had recognized a plugging and abandonment obligation primarily for its offshore properties. This liability was shown netted against oil and gas properties on the balance sheet. Under SFAS 143, the Company now recognizes 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 the Company to consider estimated salvage value in the calculation of DD&A. Consistent with industry practice, historically the Company had assumed the cost of plugging and abandonment on

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its 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) an 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 by the Company 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 reserves estimates, external estimates as to the cost to plug and abandon the wells in the future, and federal and state regulatory requirements. The liability is discounted using an assumed credit-adjusted risk-free interest rate of 9%. 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. While Great Lakes includes a 3% market risk premium in its abandonment estimates, Range does not as the amount would not be significant. At the time of abandonment, the Company 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, 2001 (rather than January 1, 2003), including an associated pro forma asset retirement obligation on that date of $44.0 million, are presented below (in thousands, except per share data):

			Pro Forma Year Ended December 31,		
			2003	**2002**	**2001**
Net income			$35,415	$24,535	$17,854
Earnings per share	-	basic	$ 0.64	$ 0.46	$ 0.36
	-	diluted	$ 0.61	$ 0.45	$ 0.35

A reconciliation of the Company s liability for plugging and abandonment costs for the year ended December 31, 2003 is as follows (in thousands):

Asset retirement obligation, December 31, 2002	$
Cumulative effect adjustment	51,390
Liabilities incurred	4,598
Liabilities settled	(2,165)
Accretion expense	4,517
Change in estimate	(6,496)[a]
Asset retirement obligation, December 31, 2003	$51,844

(a) Change in estimate attributable to ARO deferred to a future period by third party operator.

The pro forma asset retirement obligations as of December 31, 2000, 2001 and 2002 would be $44.0 million, $48.3 million and $53.8 million, respectively had the Company previously adopted SFAS 143.

(5) SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31,		
	2003	**2002**	**2001**
	(in thousands)		
Non-cash investing and financing activities:			
Common stock issued			
Under benefit plans	$ 3,672	$ 3,092	$ 2,174
Exchanged for fixed income securities	1,370	8,359	14,222
Preferred stock issued	50,000		
Cash used in (provided by) operating activities:			
Income taxes paid to (refunded by) taxing authorities	$ 110	$ (96)	$ 14
Interest paid	21,579	23,277	31,207

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(6) INDEBTEDNESS

The Company had the following debt and Trust Preferred Securities (as herein defined) outstanding as of the dates shown (in thousands) (interest rates, excluding the impact of interest rate swaps, at December 31, 2003 are shown parenthetically):

	December 31,	
	2003	2002
Senior debt:		
Senior Credit Facility (3.1%)	$178,200	$115,800
Non-recourse debt:		
Great Lakes Credit Facility (2.9%)	70,000	76,500
Subordinated debt:		
8.75% Senior Subordinated Notes due 2007		69,281
7.375% Senior Subordinated Notes due 2013, net of $1.7 million discount	98,331	
6% Convertible Subordinated Debentures due 2007	11,649	21,620
Total debt	358,180	283,201
Trust Preferred Securities manditorily redeemable securities of subsidiary		84,840
Total	$358,180	$368,041

Interest paid in cash during the years ended December 31, 2003 and 2002 totaled $19.6 million and $23.3 million, respectively. In 2003, the Company also paid a $2.0 million call premium in connection with the redemption of the 8.75% Notes. No interest expense was capitalized during 2003 and 2002.

Senior Credit Facility

In 2002, the Company entered into an amended and restated $225.0 million secured revolving bank facility which is secured by substantially all of the assets of the Company (excluding the Company s interest in Great Lakes). 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 23, 2003, the borrowing base was increased from $180.0 million to $225.0 million. As of December 31, 2003, the outstanding balance under the Senior Credit Facility was $178.2 million and there was $46.7 million of borrowing capacity available. The loan matures on January 1, 2007. Borrowings 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 0.25% to 1.0% 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, the Company pays 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 1.50% and 2.25% per annum depending on the total outstanding under the Senior Credit Facility relative to the borrowing base under the Senior Credit Facility. The Company 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 part of its base rate loans to LIBOR loans. The weighted average interest rate (including applicable margin) was 3.1% and 3.9% for the years ended December 31, 2003 and 2002, respectively. A commitment fee is paid on the undrawn balance based on an annual rate of 0.375% to 0.50%. At December 31, 2003, the commitment fee was 0.375% and the interest rate margin was 2.0%. At February 26, 2004, the interest rate (including applicable margin) was 3.1%.

Great Lakes Credit Facility

The Company consolidates its proportionate share of borrowings on the Great Lakes $275.0 million secured revolving bank facility (the Great Lakes Credit Facility). The Great Lakes Credit Facility is non-recourse to the Company and provides for a borrowing base subject to redeterminations semi-annually each April and October and pursuant to certain unscheduled redeterminations. As of December 31, 2003, the Company s portion of the outstanding balance owed under the Great Lakes Credit Facility was $70.0 million. The loan matures on January 1, 2007. Any advance under the commitment may be a base rate loan or a Eurodollar loan. On all base rate loans the Company pays a varying rate per annum equal to the lesser of (i) the maximum nonusurious rate of interest under applicable law, or (ii) the sum of the base rate plus a base rate margin of between 0.25% to 0.75% per annum depending on the amounts outstanding on the loan, plus all outstanding letters of credit, divided by the borrowing base under the Great Lakes Credit Facility. On all Eurodollar loans, the Company pays a varying rate per annum equal to the lesser of (i) the maximum nonusurious rate of interest under applicable law, or (ii) the Eurodollar rate plus a Eurodollar margin of between 1.50% to 2.0% per annum depending on the amounts outstanding on the loan, plus all outstanding letters of credit, divided by the borrowing base under the Great Lakes Credit Facility. Great Lakes may elect, from time to time, to convert all or any part of its Eurodollar loans to base rate loans or to convert all or any part of its base rate loans to Eurodollar loans. Cash distributions to members of the joint venture are limited by a covenant contained in the Great Lakes Credit Facility. A commitment fee is paid on the undrawn balance at an annual rate of 0.25% to 0.50%. At December 31, 2003, the commitment fee was 0.375% and the interest rate margin was 1.75%. The average interest rate on the Great Lakes Credit Facility, excluding hedges, was 3.0% and 3.9% for the twelve months ended December 31, 2003 and 2002. After hedging (see Note 7), the rate was 5.4% and 6.8% for the years ended December 31, 2003 and 2002. At February 26, 2004, the interest rate was 2.9% excluding hedges and 5.1% after hedging.

8.75% Senior Subordinated Notes due 2007

In 1997, the Company sold $125 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, the Company 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 in the Company s Statements of Operations in the year ended 2003. The redemption was financed by the issuance of the 7.375% senior subordinated notes due 2013.

7.375% Senior Subordinated Notes due 2013

On July 21, 2003, the Company issued $100.0 million aggregate principal amount of 7.375% Senior Subordinated Notes due 2013. The offering of the 7.375% Senior Subordinated Notes due 2013 (the Outstanding Notes), was not registered under the Securities Act of 1933, as amended (the Securities Act). The securities were issued in compliance with Rule 144A and Regulation S under the Securities Act. On October 23, 2003, $100.0 million aggregate principal amount of the Outstanding Notes were exchanged for $100.0 million principal amount of the Company s 7.375% Senior Subordinated Notes due 2013 issued in a registered exchange offer for which a registration statement was filed under the Securities Act (the Exchange Notes) as required by the Registration Rights Agreement, by and among the Company and UBS Securities LLC, Banc One Capital Markets, Inc., Credit Lyonnais Securities (USA) Inc., and McDonald Investments (the Registration Rights Agreement). The Exchange Notes are identical to the Outstanding Notes except that the Exchange Notes are registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest. As used in this Form 10-K, the term 7.375% Notes refer to both the Outstanding Notes and the Exchange Notes. The Company pays 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. The 7.375% Notes are guaranteed by certain of the Company s 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 in interest expense.

The Company may redeem the 7.375% Notes, in whole or in part, at any time on or after July 15, 2008, at redemption prices from 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, the Company 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 the Company experiences a change of control, the Company may be required 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 the Company s and the Subsidiary Guarantors senior debt and will be subordinated to future senior debt that the Company and the Subsidiary Guarantors are permitted to incur under the senior credit facilities and the indenture governing the 7.375% Notes.

6% Convertible Subordinated Debentures due 2007

In 1996, the Company sold $55.0 million principal amount of 6% Convertible Subordinated Debentures due 2007 (the 6% Debentures). Interest on the 6% Debentures is payable semi-annually each February and August. The 6% Debentures are convertible into shares of the Company s common stock at the option of the holder at any time prior to maturity, unless previously redeemed or repurchased, at a conversion price of $19.25 per share, subject to adjustment in

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certain events. The 6% Debentures will mature in 2007. The 6% Debentures are subject to redemption at the Company s option, in whole or in part, at redemption prices from 102.5% of the principal amount as of December 31, 2003, and declining to 101.0% in 2006. Upon a change of control, the Company is required to offer to repurchase each holder s 6% Debenture at a purchase price equal to 100% of the principal amount thereof, plus accrued and unpaid interest to the date of repurchase. The 6% Debentures are unsecured general obligations and are subordinated to all senior indebtedness.

During 2003 and 2002, $880,000 and $7.1 million of 6% Debentures were retired at a discount in exchange for 129,000 and 1.2 million shares of common stock, respectively. The Company recorded a $465,000 conversion expense related to the 2003 exchange (see discussion below). In addition, $9.1 million and $815,000 were repurchased for cash in 2003 and 2002, respectively. On February 26, 2004, $11.6 million of the 6% Debentures was outstanding.

5.75% Trust Preferred Securities Manditorily Redeemable Securities of Subsidiary

In 1997, the Company issued $120.0 million of the 5.75% Trust Convertible Preferred Securities (the Trust Preferred Securities) through a newly-formed affiliate Lomak Financing Trust (the Trust). The Trust issued 2,400,000 shares of the Trust Preferred Securities at $50 per share. Each Trust Preferred Security was convertible at the holder s option into shares of the Company s common stock, at a conversion price of $23.50 per share. The Trust invested the $120 million of proceeds in the 5.375% convertible junior subordinated debentures (the Junior Debentures). The sole assets of the Trust were the Junior Debentures.

The accounts of the Trust were included in the consolidated financial statements after eliminations. Distributions of the Trust were recorded as interest expense in the Consolidated Statements of Operations. During 2003, $5.3 million of the Trust Preferred Securities were repurchased for $4.1 million. In addition, in September 2003, the Company 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 held by the largest holder of the Trust Preferred Securities. The Convertible Preferred was exempt from registration under Section 3(a)(9) of the Securities Act because the Convertible Preferred was only exchanged by the Company with that holder and no commission or other remuneration was paid or given directly or indirectly for soliciting such exchange. The Company paid approximately $550,000 in consulting fees for financial advice regarding enhancing the Company s financial position. In December 2003, the remainder of the Trust Preferred Securities was redeemed.

Debt Covenants

The debt agreements contain covenants relating to net worth, working capital, dividends and financial ratios. The Company was in compliance with all covenants at December 31, 2003. 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 (excluding Great Lakes) plus 66-2/3% of distributions, dividends or payments of debt from or proceeds from sales of equity interests of Great Lakes plus 66-2/3% of net cash proceeds from common stock issuances. In addition, there is a separate restricted basket that allows for the proceeds from the issuance of the 7.375% Notes to be used to repurchase junior securities. Approximately $37.5 million was available under the Senior Credit Facility s restricted payment basket on December 31, 2003 and $5.5 million available under the separate restricted basket. 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. The 7.375% Notes also include a separate restricted payments basket of $25.0 million to repurchase junior securities. At December 31, 2003, approximately $18.6 million was available under the 7.375% Notes restricted payments basket and $2.0 million under the separate basket.

Following is the principal maturity schedule for the long-term debt outstanding as of December 31, 2003 (in thousands):

Year Ended December 31:	
2004	$
2005	
2006	
2007	259,849
2008	
2009	
Thereafter	98,331
	$358,180

Induced Conversions

In September 2002, the Emerging Issues Task Force (EITF) issued EITF Issue No. 02-15, Determining Whether Certain Conversions of Convertible Debt to Equity Securities are Within the Scope of FASB Statement No. 84 Induced Conversions of Convertible Debt (SFAS 84). SFAS 84 was issued to amend APB Opinion No. 26, Early Extinguishment of Debt to exclude from its scope convertible debt that is converted to equity securities of the debt or pursuant to conversion privileges different from those included in the terms of the debt at issuance, and the change in conversion privileges is effective for a limited period of time, involves additional consideration, and is made to induce conversion. SFAS 84 applies only to conversions that both (a) occur pursuant to changed conversion privileges that are exercisable only for a limited period of time and (b) include the issuance of all of the equity securities issuable pursuant to conversion privileges included in the terms of the debt at issuance for each debt instrument that is converted. The Task Force reached a consensus that SFAS 84 applies to all conversions that both (a) occur pursuant to changed conversion privileges that are exercisable only for a limited period of time and (b) include the issuance of all of the equity securities issuable pursuant to conversion privileges included in the terms of the debt at issuance for each debt instrument that is converted, regardless of the party that initiates the offer. This consensus should be applied prospectively to debt conversions completed after September 11, 2002. Since 1999, the Company has retired certain of the 6% Debentures and the Trust Preferred Securities, each of which are convertible into the Company s common stock, by either purchasing securities for cash or issuing common stock in exchange for such securities. Since the exchanges of common stock for these convertible debt securities were at relative market values, the convertible securities were retired at a discount to face value. Under the provisions of SFAS 84, when an inducement is issued to retire convertible debt, the face value of the convertible debt security shall be charged to stockholders equity (common stock and paid in capital), the shares of common stock issued in excess of the shares that would have been issued under the terms of the debt instrument are expensed at the market value of such shares and an offsetting increase to paid in capital will also be recorded.

(7) FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

The Company s 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 are considered to be representative of fair value because of their short maturity. Since the Company marks to market through OCI all derivatives, 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.

A portion of future oil and gas sales is periodically hedged through the use of collars or swap contracts. Realized gains and losses on these instruments are reflected in the contract month being hedged as an adjustment to oil and gas revenue. At times, the Company seeks to manage interest rate risk on its credit facilities through the use of swaps. Gains and losses on these swaps are included as an adjustment to interest expense in the relevant periods.

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

	December 31, 2003		December 31, 2002	
	Book	**Fair**	**Book**	**Fair**
Assets				
Cash and equivalents	$ 631	$ 631	$ 1,334	$ 1,334
Accounts receivable	37,745	37,745	26,832	26,832
IPF receivable	12,593	12,593	24,451	24,451
Marketable securities[(b)]	1,765	1,765	1,040	1,040
Interest rate swaps	265	265		
Commodity swaps and collars	101	101	17	17

Total	53,100	53,100	53,674	53,674
Liabilities				
Commodity swaps and collars	(70,725)	(70,725)	(32,964)	(32,964)
Interest rate swaps	(647)	(647)	(2,150)	(2,150)
Long-term debt[(a)]	(358,180)	(358,564)	(283,201)	(279,894)
Trust Preferred Securities			(84,840)	(52,177)
Total	(429,552)	(429,936)	(403,155)	(367,185)
Net financial instruments	$(376,452)	$(376,836)	$(349,481)	$(313,511)

[(a)] Fair Value based on quotes received from certain brokerage houses. Quotes for December 31, 2003 were 100.5% for the 7.375% Notes and 99% for the 6% Debentures.

[(b)] Marketable securities held in the deferred compensation plan.

At December 31, 2003, the Company had open hedging contracts covering 52.6 Bcf of gas at prices averaging $4.13 per mcf, 1.4 million barrels of oil at prices averaging $25.74 barrel and 0.7 million barrels of NGLs at prices averaging $21.02 per barrel. The Company also has collars covering 6.6 Bcf of gas at weighted average floor and cap prices of $4.14 to

$6.19 per mcf and 1.2 million barrels of oil at weighted average floor and cap prices of $24.16 to $29.24 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 pretax loss of $70.6 million at December 31, 2003. 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. Net pretax losses incurred relating to these derivatives for the year ended December 31, 2001 was $6.2 million. A hedging gain of $17.8 million was realized in 2002. In 2003, a loss of $60.4 million was incurred. These hedging positions are recorded on the Company s Consolidated Balance Sheets 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 Statements of Operations was decreased for ineffective hedging losses of $1.2 million and $2.7 million in the year ended December 31, 2003 and 2002, respectively. The year ended December 31, 2001 included ineffective hedging gains of $2.4 million.

The following table sets forth the hedging volumes by year:

Contract Type	Period	Volume Hedged	Average Hedge Price
Natural gas			
Swaps	2004	91,440 MMBtu/day	$ 4.08
Swaps	2005	50,695 MMBtu/day	$ 4.21
Swaps	2006	1,644 MMBtu/day	$ 4.80
Collars	2004	6,470 MMBtu/day	$4.38 - $ 6.19
Collars	2005	11,517 MMBtu/day	$4.14 - $ 5.80
Crude oil			
Swaps	2004	3,010 Bbl/day	$25.93
Swaps	2005	940 Bbl/day	$25.11
Collars	2004	2,128 Bbl/day	$24.18 - $29.24
Collars	2005	1,233 Bbl/day	$24.16 - $27.48
Natural gas liquids			
Swaps	2004	1,377 Bbl/day	$21.88
Swaps	2005	658 Bbl/day	$19.20

The following schedule shows the effect of the closed oil and gas hedges since January 1, 2001 and the value of open contracts at December 31, 2003 (in thousands):

Quarter Ended	Hedging Gain (Loss)
Closed Contracts	
2001	
March 31, 2001	$ (23,440)
June 30, 2001	(5,250)
September 30, 2001	8,450
	14,047

December 31, 2001	
Subtotal	(6,193)
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)
Total net realized loss	$ (48,830)

Quarter Ended	**Hedging Gain (Loss)**
Open Contracts	
2004	
March 31, 2004	$ (19,240)
June 30, 2004	(12,271)
September 30, 2004	(11,221)
December 31, 2004	(10,966)
Subtotal	(53,698)
2005	
March 31, 2005	$ (8,242)
June 30, 2005	(2,721)
September 30, 2005	(2,648)
	(3,363)

December 31, 2005		
Subtotal		(16,974)
2006		
March 31, 2006	$	(47)
June 30, 2006		41
September 30, 2006		44
December 31, 2006		10
Subtotal		48
Total net liability '	$	(70,624)

Through Great Lakes, the Company uses interest rate swap agreements to manage the risk that future cash flows associated with interest payments on amounts outstanding under the variable rate Great Lakes Credit Facility may be adversely affected by volatility in market interest rates. Under swap agreements, the Company agrees 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 the Company s 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 the Company s interest payments are made. The ineffective portion of the changes in fair value of the Company s interest rate swaps is recorded in interest expense in the period incurred. At December 31, 2003, Great Lakes had interest rate swap agreements totaling $110.0 million, 50% of which is consolidated by the Company. These swaps consist of two agreements totaling $45.0 million at 7.1% which expire in May 2004, two agreements totaling $20.0 million at rates of 2.3% which expire in December 2004, 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 Company s share of the fair value of the swaps at December 31, 2003, was a net hedge liability of $382,000 based on current quotes. On December 31, 2003, the 30-day LIBOR rate was 1.1%. The Company recognized additional interest expense of $1.3 million, $2.4 million and $1.1 million due to interest swaps in 2003, 2002 and 2001, respectively.

The combined fair value of net losses on oil and gas hedges and net losses on interest rate swaps totaling $71.0 million appear as Unrealized derivative gains and Unrealized derivative losses on the Consolidated Balance Sheet at December 31, 2003. Hedging activities are conducted with major financial or commodities trading institutions which management believes are acceptable credit risks. At times, such risks may be concentrated with certain counterparties. The credit worthiness of these counterparties is subject to continuing review.

(8) COMMITMENTS AND CONTINGENCIES

The Company is involved in various legal actions and claims arising in the ordinary course of business, which includes a royalty owner suit filed in 2000 asking for class action certification against Great Lakes and the Company. In the opinion of management, such litigation and claims are likely to be resolved without material adverse effect on the Company s financial position or results of operations. During 2003, approximately $450,000 of costs were incurred in defense of litigation. The Company periodically enters into arrangements to purchase seismic data over several years. These commitments totaled $1.2 million in 2004 and $215,000 in 2005. The Company records exploration expense as the data is received.

The Company leases certain office space and equipment under cancelable and non-cancelable leases, most of which expire within three years and may be renewed by the Company. Rent expense under such arrangements totaled $1.6 million, $1.7 million and $1.7 million in 2003, 2002 and 2001, respectively. Future minimum rental commitments under non-cancelable leases are as follows (in thousands):

2004	$2,567
2005	2,403
2006	1,344
2007	425
2008 and thereafter	274
	$7,013

(9) STOCKHOLDERS EQUITY

The Company has 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, the Company issued 1.0 million shares of Convertible Preferred, par value $1.00 and liquidation preference $50 per share. The Convertible Preferred is convertible into common stock at $8.50 per share. Each share is non-voting. Beginning in September 2007, the Company may, at its election, redeem the Convertible Preferred for cash at 103% and declines to 100% in September 2012. Beginning in September 2005, the Company may at its sole election, cause the Convertible Preferred to convert, in whole but not in part, to common stock if, at the time, the common stock has closed at $11.90 or higher for 20 of the previous consecutive 30 trading days. Accrued dividends are cumulative and are payable quarterly in arrears. The following is a schedule of changes in the number of outstanding common shares since the beginning of 2002:

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	Year Ended December 31,	
	2003	2002
Beginning balance	54,991,611	52,643,275
Issuances:		
Employee benefit plans	514,002	417,661
Stock options exercised	687,885	130,566
Stock purchase plan	87,500	168,500
Exchanged for:		
8.75% Notes		182,709
6% Debentures	128,793	1,165,700
Trust Preferred Securities		283,200
	1,418,180	2,348,336
Ending balance	56,409,791	54,991,611

(10) STOCK OPTION AND PURCHASE PLANS

The Company has four stock option plans, of which two 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. Information with respect to the option plans is summarized below:

	Inactive		Active			
	Domain Plan	1989 Plan	Directors Plan	1999 Plan	Total	Average Exercise Price
Outstanding at December 31, 2000	248,965	1,182,893	136,000	665,200	2,233,058	$ 6.23
Granted			56,000	774,350	830,350	6.46
Exercised	(111,481)	(59,113)		(53,000)	(223,594)	1.63
Expired/cancelled		(581,080)	(72,000)	(71,437)	(724,517)	13.05
Outstanding at December 31, 2001	137,484	542,700	120,000	1,315,113	2,115,297	4.47
Granted			48,000	1,438,850	1,486,850	4.89
Exercised	(5,782)	(56,157)	(2,000)	(66,627)	(130,566)	2.45
Expired/cancelled		(32,963)	(14,000)	(142,474)	(189,437)	4.95

Outstanding at December 31, 2002	131,702	453,580	152,000	2,544,862	3,282,144	4.46
Granted			56,000	1,634,400	1,690,400	5.92
Exercised	(59,038)	(209,581)	(4,000)	(415,266)	(687,885)	3.55
Expired/cancelled		(8,825)		(444,699)	(453,524)	5.46
Outstanding at December 31, 2003	72,664	235,174	204,000	3,319,297	3,831,135	$ 5.00

There were options exercisable of 585,526 (weighted average price of $4.04), 975,026 (weighted average price of $4.46) and 1,133,850 (weighted average price of $5.00) at December 31, 2001, 2002 and 2003, respectively.

In 1999, shareholders approved the stock option plan (the 1999 Plan) providing for the issuance of options on 1.4 million common shares. In 2001, shareholders approved an increase in the number of options issuable to 3.4 million shares. In May 2002, shareholders approved an increase in the number of options issuable to 6.0 million. In May 2003, shareholders approved an increase in the number of options issuable to 8.75 million. All options issued under the 1999 Plan through May 22, 2002 vested over 5 years and had a maximum term of 10 years. Options issued under the 1999 Plan after May 22, 2002 vest over a three year period and have a maximum term of five years. During the year ended December 31, 2003, 1.6 million options were granted under the 1999 Plan at exercise prices from $5.62 to $7.00 a share. At December 31, 2003, 3.3 million options were outstanding under the 1999 Plan at exercise prices of $1.94 to $7.00.

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The Company maintains 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, 2003, 235,174 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.

In 1994, shareholders approved the Outside Directors Stock Option Plan (the Directors Plan). In 2000, shareholders approved an increase in the number of options issuable to 300,000, extended the term of the options to ten years and set the vesting period at five years. Effective May 22, 2002, the term of the option was changed to five years with vesting immediately upon grant. 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, 2003, 56,000 options were granted under the Directors Plan at exercise prices of $5.64 and $5.70 share. At December 31, 2003, 204,000 options were outstanding under the Directors Plan at exercise prices of $2.82 to $6.00.

The Domain stock option plan was adopted when that company was acquired in 1998, with existing Domain options becoming exercisable into the Company s common stock. No options have been granted under this plan since the acquisition. At December 31, 2003, 72,664 options remained outstanding under the Plan at a price of $3.46 a share. In January 2004, all outstanding options were exercised and the plan was terminated.

In total, approximately 3.8 million options were outstanding at December 31, 2003 at exercise prices ranging from $1.94 to $7.63 as follows:

			Inactive		Active		
Range of Exercise price	Average Exercise price	Weighted Average Remaining Life (Yrs)	Domain Plan	1989 Plan	Directors Plan	1999 Plan	Total
$1.94-$4.99	$ 3.52	5.92	72,664	101,824	52,000	716,723	943,211
5.00 - 7.63	5.97	5.10		133,350	152,000	2,602,574	2,887,924
		Total	72,664	235,174	204,000	3,319,297	3,831,135

During 2003, the Company issued 234,000 restricted shares of the Company s common stock as compensation to directors, officers and key employees of the Company. The restricted share awards included 136,000 that were granted to directors of the Company which were approved by the Compensation Committee and were immediately vested. Upon the hiring of the new chief operating officer and new chief financial officer, the Company granted 30,000 shares which vest over three years. The remaining 68,000 restricted shares were awarded to officers and key employees with vesting over three year period. The Company recorded $753,000 of compensation expense in 2003 related to these awards.

In 1997, shareholders approved a plan (the Stock Purchase Plan) authorizing the sale of 900,000 shares of common stock to officers, directors, key employees and consultants. In 2001, shareholders 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, the Company recorded additional compensation expense of $122,000, $227,800 and $375,000 during 2003, 2002 and 2001, respectively. Through December 31, 2003, 1,377,319 shares have been sold under the Stock Purchase Plan. At December 31, 2003, there were no rights outstanding to purchase shares.

(11) DEFERRED COMPENSATION

In 1996, the Board of Directors of the Company adopted a deferred compensation plan (the Plan). The Plan gives certain officers and key employees the ability to defer all or a portion of their salaries and bonuses and invests in common stock of the Company or makes other investments at the employee s discretion. The assets of the Plan are held in a rabbi trust (the Rabbi Trust) and are therefore available to satisfy the claims of the Company s creditors in the event of bankruptcy or insolvency of the Company. The Company s 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 of the Company 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 the Company s Consolidated Statements of Operations. The assets of the Rabbi Trust, other than common stock of the Company, are invested in marketable securities and reported at market value in other assets on the Company s Consolidated Balance Sheets. The deferred compensation liability on the Company s Consolidated

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Balance Sheets reflects the market value of the marketable securities and the Company s common stock held in the Rabbi Trust. The cost of common stock held in the Rabbi Trust is shown as a reduction to stockholders equity. Changes in the market value of the marketable securities are reflected in OCI, while changes in the market value of the Company s common stock held in the Rabbi Trust is charged or credited to general and administrative expense each quarter. The Company recorded mark-to-market expenses related to deferred compensation of $6.6 million in 2003, $1.1 million in 2002 and a benefit of $2.4 million in 2001. Since the Company actually issues the common shares to the Rabbi Trust, the Company does not incur additional cash expense other than the original fair market value of the stock when issued.

(12) BENEFIT PLAN

The Company maintains a 401(k) Plan for its employees. The Plan permits employees to contribute up to 50% of their salary (subject to Internal Revenue limitations) on a pretax basis. Historically, the Company has made discretionary contributions of the Company s common stock to the 401(k) Plan annually. All Company contributions become fully vested after the individual employee has three years of service with the Company. In 2003, 2002 and 2001, the Company contributed $610,000, $602,000 and $554,000, at then market values, respectively, of the Company s common stock to the 401(k) Plan. The Company does 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 Company stock based on their personal investment strategy.

(13) INCOME TAXES

The Company s federal income tax expense (benefit) for the years ended December 31, 2003, 2002 and 2001, was $18.5 million, ($3.4 million) and ($406,000), respectively. In addition, $2.4 million of tax expense was recognized as part of the cumulative effect of change in accounting principle. A reconciliation between the statutory federal income tax rate and the Company s effective income tax rate is as follows:

	Year Ended December 31,		
	2003	**2002**	**2001**
		($ in thousands)	
Federal statutory tax rate	35%	35%	35%
Gain on retirement of securities		6	10
Permanent differences		(1)	1
Valuation allowance		(63)	(45)
State	2	1	(1)
Other		4	(4)
Consolidated effective tax rate	37%	(18)%	(4)%
Income taxes paid (refunded)	$110	($96)	$ 14

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

	Year Ended December 31,		
	2003	2002	2001
	(in thousands)		
Current:			
U.S. federal	$ 191	$ (95)	$(355)
U.S. state and local	(21)	91	(51)
	$ 170	$ (4)	$(406)
Deferred:			
U.S. federal	$17,329	$(3,227)	$
U.S. state and local	990	(127)	
	$18,319	$(3,354)	$

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The Company follows SFAS Statement No. 109, Accounting for Income Taxes, pursuant to which the liability method is used. Under this method, deferred tax assets and liabilities are determined based on differences between financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and regulations that will be in effect when the differences are expected to reverse. Significant components of deferred tax liabilities and assets are as follows:

	December 31,	
	2003	2002
	(in thousands)	
Deferred tax assets		
Net operating loss carryover	$ 69,855	$ 71,661
Allowance for doubtful accounts	3,941	4,717
Percentage depletion carryover		5,256
Net unrealized loss in OCI	24,620	11,388
AMT credits and other	4,813	665
Total deferred tax assets	103,229	93,687
Deferred tax liabilities		
Depreciation and depletion	(90,651)	(77,902)
Unrealized gain on hedging		
Valuation allowance	(3,550)	
Net deferred tax asset	$ 9,028	$ 15,785

At December 31, 2003, deferred tax assets exceeded deferred tax liabilities by $9.0 million with $24.6 million of deferred tax assets related to net deferred hedging losses included in OCI. A portion of the Company s deferred tax assets relate to items which are capital assets, which upon disposition will result in capital losses. Due to the unlikely ability of the Company to utilize the capital loss, a valuation allowance was recognized in the amount of $3.5 million.

At December 31, 2003, the Company had regular net operating loss (NOL) carryovers of $188.8 million and alternative minimum tax (AMT) NOL carryovers of $161.0 million that expire between 2012 and 2021. Regular NOLs generally offset taxable income and to such extent, no income tax payments are required. For the period ending December 31, 2003, the Company will pay approximately $0.2 million in AMT. The Company has $26.9 million of NOLs generated in years prior to 1998 which are subject to yearly limitations due to IRC Section 382. The Company does not believe the application of the Section 382 limitation hinders their ability to utilize such NOLs and therefore, no valuation allowance has been provided. At December 31, 2003, the Company has AMT credit carryovers of $2.4 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,		
	2003	2002	2001
Numerator:			
Income before cumulative effect of change in accounting principle	$30,924	$25,766	$17,663
Gain on retirement of preferred stock			556
Preferred stock dividends	(803)		(10)
Numerator for basic earnings per share before cumulative effect of change in accounting principle	30,121	25,766	18,209
Cumulative effect of accounting change	4,491		
Numerator for basic earnings per share	$34,612	$25,766	$18,209
Income before cumulative effect of change in accounting principle	$30,924	$25,766	$17,663
Gain on retirement of preferred stock			556
Numerator for diluted earnings per share before cumulative effect of change in accounting principle	30,924	25,766	18,219
Cumulative effect of accounting change	4,491		
Numerator for diluted earnings per share after assumed conversions and cumulative effect of change in accounting principle	$35,415	$25,766	$18,219

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	Year Ended December 31,		
	2003	2002	2001
Denominator:			
Weighted average shares outstanding	55,796	54,283	51,159
Stock held in deferred compensation plan	(1,524)	(1,213)	(1,002)
Weighted average shares, basic	54,272	53,070	50,157
Effect of dilutive securities:			
Weighted average shares outstanding	55,796	54,283	51,159
Employee stock options and other	442	135	106
Common shares assumed for Convertible Preferred	1,612		
Dilutive potential common shares for diluted earnings per share	57,850	54,418	51,265
Earnings per share basic and diluted:			
Before cumulative effect of accounting change			
Basic	$ 0.56	$ 0.49	$ 0.36
Diluted	$ 0.53	$ 0.47	$ 0.36
After cumulative effect of accounting change			
Basic	$ 0.64	$ 0.49	$ 0.36
Diluted	$ 0.61	$ 0.47	$ 0.36

During 2003, 2002, and 2001, 566,000, 160,000 and 129,000 stock options were included in the computation of diluted earnings per share.

(15) MAJOR CUSTOMERS

The Company markets its production on a competitive basis. Gas is sold under various types of contracts ranging from life-of-the-well 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. The Company sells to oil purchasers on the basis of price and service. For each of the years ended December 31, 2003, 2002 and 2001, three customers accounted for 10% or more of total oil and gas revenues and the combined sales to those three customers accounted for 49%, 35% and 50% of total oil and gas revenues, respectively. Management believes that the loss of any one customer would not have a material long-term adverse effect on the Company.

From the inception of the Great Lakes joint venture through June 30, 2001, Great Lakes sold approximately 90% of its gas production to FirstEnergy, at prices based on the close of NYMEX each month plus a basis differential. FirstEnergy is a 50% owner in the Great Lakes joint venture. Effective July 1, 2001, Great Lakes began selling its gas to different companies, including FirstEnergy. In the year ended December 31, 2003, approximately 96% of Great Lakes gas was sold at prices based on the close of NYMEX contracts each month plus a basis differential. The remainder is sold at a fixed price.

(16) OIL AND GAS ACTIVITIES

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

	Year Ended December 31,		
	2003	2002	2001
		(in thousands)	
Oil and gas properties:			
Properties subject to depletion	$1,350,616	$1,135,590	$1,021,898
Unproved properties	12,195	18,959	25,731
Total	1,362,811	1,154,549	1,047,629
Accumulated depletion	(639,429)	(590,143)	(514,272)
Net	$ 723,382	$ 564,406	$ 533,357

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	Year Ended December 31,		
	2003	**2002**	**2001**
Costs incurred:			
Acquisitions:			
Unproved leasehold	$ 5,580	$ 6,147	$ 5,262
Proved oil and gas properties	90,723	15,632	4,227
Gas gathering facilities	4,622	11	
Development	83,433	66,284	69,162
Exploration[a]	22,564	23,232	11,405
Total[b]	$206,922	$111,306	$90,056

[a] Includes $13,946, $11,525, and $5,879 of exploration cost expensed in 2003, 2002 and 2001, respectively.

[b] The Company has not included asset retirement obligation accruals in the costs incurred for oil and gas producing activities. For the year ended December 31, 2003, $3.4 million of asset retirement obligations were accrued for new wells and changes in estimates.

(17) INVESTMENT IN GREAT LAKES

The Company owns 50% of Great Lakes and consolidates its proportionate interest in the joint venture s assets, liabilities, revenues and expenses. The following table summarizes the 50% interest in Great Lakes audited financial statements as of or for the years ended December 31, 2003 and 2002:

	December 31, 2003	December 31, 2002
	(in thousands)	
Balance Sheet:		
Current assets	$ 8,935	$ 8,356
Oil and gas properties, net	217,613	185,233
Transportation and field assets, net	14,735	15,428
Unrealized derivative gain	250	13
Other assets	295	117
Current liabilities	24,690	17,909
Unrealized hedging loss	4,533	3,188
ARO liability	16,413	
Long-term debt	70,000	76,500
Members equity	126,192	111,550
Statement of Operations:		
Revenues	$ 56,543	$ 52,201
Direct operating expense	10,221	7,996

Exploration expense	1,931	2,434
G&A expense	1,876	1,758
Interest expense	3,884	5,353
DD&A	14,568	14,257
Pretax income	24,063	20,403
Cumulative effect of change in accounting principle (before income taxes)	1,601	
Net income[a]	25,664	20,403

[a] Great Lakes, which is a limited liability corporation, does not provide for income taxes. Accordingly, there is no tax provision in the earnings disclosed above. However, the Company does recognize tax expense on Great Lakes earnings in its consolidated tax provision.

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(18) GAIN ON RETIREMENT OF SECURITIES

During 2003, 129,000 shares (including shares issued for interest) 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 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. During 2001, 1.8 million shares of common stock were exchanged for $2.9 million of Trust Preferred Securities, $5.7 million of 6% Debentures and $3.4 million of 8.75% Notes. In addition, $50,000 of Trust Preferred Securities, $2.3 million of 6% Debentures and $42.5 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 $19.0 million, $3.1 million and $4.0 million were recorded in 2003, 2002 and 2001, respectively, because the securities were retired at a discount.

(19) UNAUDITED SUPPLEMENTAL RESERVE INFORMATION

The Company and its 50% pro rata portion of Great Lakes proved oil and gas reserves are located in the United States. Proved reserves are those quantities of crude oil and natural gas which, based upon analysis of geological and engineering data, can with reasonable certainty be recovered in the future from known oil and gas reservoirs. 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 oil and gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage.

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.

Estimated Net Proved Oil and Natural Gas Reserves Reserves of crude oil, condensate, natural gas liquids and natural gas are estimated by the Company s 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 U.S. Securities and Exchange Commission 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 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 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 the benchmark prices of $32.52 per barrel and $6.19 per Mmbtu. The average 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 the benchmark NYMEX prices of $31.17 per barrel and $4.75 per Mmbtu. The average prices at December 31, 2001 were $17.59 per barrel for oil, $12.38 per barrel for natural gas liquids and $2.70 per mcf for gas using the benchmark NYMEX prices of $20.38 per barrel and $2.63 per Mmbtu.

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Quantities of Proved Reserves

	Crude Oil and NGLs	Natural Gas	Natural Gas Equivalents
	(Mbbls)	(Mmcf)	(Mmcfe)
Balance, December 31, 2000	26,002	427,667	583,679
Revisions	(3,359)	(33,575)	(53,728)
Extensions, discoveries and additions	479	31,542	34,414
Purchases	427	5,761	8,325
Sales	(627)	(190)	(3,955)
Production	(2,242)	(42,278)	(55,730)
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
Proved developed reserves			
December 31, 2001	14,066	276,162	360,558
December 31, 2002	17,176	320,224	423,280
December 31, 2003	24,912	344,187	493,659

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.

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Standardized Measure

	As of December 31,		
	2003	2002	2001
		(in thousands)	
Future cash inflows	$3,803,479	$2,697,068	$1,397,897
Future costs:			
Production	(842,052)	(677,214)	(471,144)
Development	(274,029)	(204,137)	(176,799)
Future net cash flows	2,687,398	1,815,717	749,954
Income taxes	(740,965)	(463,980)	(87,745)
Total undiscounted future net cash flows	1,946,433	1,351,737	662,209
10% discount factor	(943,452)	(852,104)	(350,801)
Standardized measure	$1,002,981	$ 499,633	$ 311,408

Changes in Standardized Measure

	As of December 31,		
	2003	2002	2001
		(in thousands)	
Standardized measure, beginning of year	$ 499,633	$ 311,408	$ 1,506,262
Revisions:			
Prices	160,932	212,091	(1,076,168)
Quantities	267,906	116,757	(8,244)
Estimated future development cost	(253,788)	(208,183)	(199,517)
Accretion of discount	96,361	39,915	196,426
Income taxes	(103,375)	(103,529)	114,556
Net revisions	168,036	57,051	(972,947)
Purchases	145,772	17,815	6,245
Extensions, discoveries and additions	110,358	60,232	25,815
Production	(177,085)	(150,511)	(165,033)
Development costs incurred	204,137	176,799	204,137

Sales	(2,117)	(1,605)	(2,967)
Changes in timing and other	54,247	28,444	(290,104)
Standardized measure, end of year	$1,002,981	$ 499,633	$ 311,408

RANGE RESOURCES CORPORATION

INDEX TO EXHIBITS

(Item 15[a 3])

Exhibit No.	Description
2.1	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 (the Company) 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 the Company s Form 8-K (File No. 001-12209) as filed with the Securities and Exchange Commission (the SEC) on January 5, 2004)
3.1.1	Restated Certificate of Incorporation of Lomak Petroleum, Inc. (Lomak) (incorporated by reference to Exhibit 3.1.1 to the Company s Form S-4 (File No. 33-108516)) as filed with the SEC on September 4, 2003)
3.1.2	Certificate of Amendment to the Certificate of Incorporation dated June 20, 1997 (incorporated by reference to Exhibit 3.1.11 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
3.1.3	Certificate of Amendment to the Certificate of Incorporation of Lomak dated August 25, 1998 (incorporated by reference to Exhibit 3.1 to the Company s Form S-8 (File No. 333-62439) as filed with the SEC on August 28, 1998)
3.1.4	Certificate of Amendment to the Certificate of Incorporation of the Company dated May 24, 2000 (incorporated by reference to Exhibit 3.1.12 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on May 7, 2003)
3.1.5	Certificate of Correction to Certificate of Amendment to the Certificate of Incorporation (incorporated by reference to Exhibit 3.1.5 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on November 5, 2003)
3.1.6	Certificate of Correction to Certificate of Amendment to the Certificate of Incorporation (incorporated by reference to Exhibit 3.1.6 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on November 5, 2003)
3.2**	Amended and Restated By-laws of the Company dated December 5, 2003
4.1.1	Form of 6% Convertible Subordinated Debentures due 2007 (contained as an exhibit to Exhibit 4.1.2 hereto)
4.1.2	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)

4.1.3 Form of 7.375% Senior Subordinated Notes due 2013 (contained as an exhibit 4.1.4 hereto)

4.1.4 Indenture dated July 21, 2003 by and among the Company, 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 the Company is Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)

4.1.5 Registration Rights Agreement dated July 21, 2003 by and between the Company and UBS Securities LLC, Banc One Capital Markets, Inc., Credit Lyonnais Securities (USA), Inc., and McDonald Investments Inc., (incorporated by reference to Exhibit 4.4.3 to the Company s 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 the Company (incorporated by reference to Exhibit 4.2 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on November 5, 2003)

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)

10.2.1 Application Service Provider and Outsourcing Agreement dated June 1, 2000 by and between Applied Terravision Systems, Inc. and the Company (incorporated by reference to Exhibit 10.4 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on August 8, 2000)

Exhibit No.	Description
10.2.2	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 the Company (incorporated by reference to Exhibit 10.1 to the Company s 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 the Company and Thomas J. Edelman (incorporated by reference to Exhibit 10.2 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
10.4.1	Amended and Restated Credit Agreement dated May 2, 2002 by and among the Company, Bank One, NA, the Lenders (as defined therein), Bank One, NA, as Administrative Agent, Fleet National Bank, as Co-Documentation Agent, Fortis Capital Corp., as Co-Documentation Agent, JPMorgan Chase Bank, as Co-Syndication Agent, Credit Lyonnais, New York Branch, as Co-Syndication Agent, Banc One Capital Markets, Inc., as Joint Lead Arranger and Joint Bookrunner, and JPMorgan Securities, Inc., as Joint Lead Arranger and Joint Bookrunner (incorporated by reference to Exhibit 10.1 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on May 7, 2002)
10.4.2	First Amendment to Amended and Restated Credit Agreement dated December 27, 2002 by and among the Company, Bank One, NA, the Lenders (as defined therein), Bank One, NA, as Administrative Agent, Fleet National Bank, as Co-Documentation Agent, Fortis Capital Corp., as Co-Documentation Agent, JPMorgan Chase Bank, as Co-Syndication Agent, Credit Lyonnais, New York Branch, as Co-Syndication Agent, Banc One Capital Markets, Inc., as Joint Lead Arranger and Joint Bookrunner, and JPMorgan Chase Bank, as Joint Lead Arranger and Joint Bookrunner (incorporated by reference to Exhibit 10.15.6 to the Company s Form 10-K (File No. 001-12209) as filed with the SEC on March 5, 2003)
10.4.3	Second Amendment to Amended and Restated Credit Agreement dated January 24, 2003 by and among the Company, Bank One, NA, the Lenders (as defined therein), Bank One, NA, as Administrative Agent, Fleet National Bank, as Co-Documentation Agent, Fortis Capital Corp., as Co-Documentation Agent, JPMorgan Chase Bank, as Co-Syndication Agent, Credit Lyonnais, New York Branch, as Co-Syndication Agent, Banc One Capital Markets, Inc., as Joint Lead Arranger and Joint-Bookrunner, and JPMorgan Chase Bank, as Joint Lead Arranger and Joint Bookrunner (incorporated by reference to Exhibit 10.1 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on May 7, 2003)
10.4.4	Third Amendment to Amended and Restated Credit Agreement dated April 1, 2003 by and among the Company, Bank One, NA, the Lenders (as defined therein), Bank One, NA, as Administrative Agent, Fleet National Bank, as Co-Documentation Agent, Fortis Capital Corp., as Co-Documentation Agent, JPMorgan Chase Bank, as Co-Syndication Agent, Credit Lyonnais, New York Branch, as Co-Syndication Agent, Banc One Capital Markets, Inc., as Joint Lead Arranger and Joint Bookrunner, and JPMorgan Securities, Inc., as Joint Lead Arranger and Joint Bookrunner (incorporated by reference to Exhibit 10.2 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on May 7, 2003)
10.4.5	Fourth Amendment to Amended and Restated Credit Agreement dated July 15, 2003 by and among the Company, Bank One, NA, the Lenders (as defined therein), Bank One, NA, as Administrative Agent, Fleet National Bank, as Co-Documentation Agent, Fortis Capital Corp., as Co-Documentation Agent, JPMorgan Chase Bank, as Co-Syndication Agent, Credit Lyonnais, New York Branch, as Co-Syndication Agent, Banc One Capital Markets, Inc., as Joint Lead Arranger and Joint Bookrunner,

and JPMorgan Securities, Inc, as Joint Lead Arranger and Joint Bookrunner (incorporated by reference to Exhibit 10.6.5 to the Company s Form S-4 (File No. 333-108516) as filed with the SEC on September 4, 2003)

10.4.6 Fifth Amendment to Amended and Restated Credit Agreement dated September 4, 2003 by and among the Company, Bank One, NA, as Administrative Agent, Fleet National Bank, as Co-Documentation Agent, Fortis Capital Corp., as Co-Documentation Agent, JPMorgan Chase Bank, as Co-Syndication Agent, Credit Lyonnais, New York Branch, as Co-Syndication Agent, Banc One Capital Markets, Inc., as joint Lead Arranger and Joint Bookrunner, and JPMorgan Securities, Inc., as Joint Lead Arranger and Joint Bookrunner (incorporated by reference to Exhibit 10.1.2 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on November 5, 2003)

10.4.7** Sixth Amendment to the Amended and Restated Credit Agreement dated October 1, 2003 by and among the Company, Bank One, NA, the Lenders (as defined therein), Bank One, NA as Administrative Agent, Fleet National Bank, as Co-Documentation Agent, Fortis Capital Corp., as Co- Documentation Agent, JP Morgan Chase Bank, as Co-Syndication Agent, Credit Lyonnais New York Branch, as Co-Syndication Agent, Banc One Capital Markets, Inc. as Joint Lead Arranger and Joint Bookrunner and JPMorgan

10.4.8** Seventh Amendment to the Amended and Restated Credit Agreement dated December 23, 2003 by and among the Company, Bank One, N.A., the Lenders (as defined therein), Bank One, NA as Administrative Agent, Fleet National Bank, as Co-Documentation Agent, Fortis Capital Corp., as Co-Documentation

Exhibit No.	Description
	Agent, JP Morgan Chase Bank, as Co-Syndication Agent, Credit Lyonnais New York Branch, as Co-Syndication Agent, Bank One Capital Markets, Inc., as Joint Lead Arranger and Joint Bookrunner and JPMorgan Securities, Inc., as Joint Lead Arranger and Joint Bookrunner
10.5.1	Restated Credit Agreement dated May 3, 2002 by and among Great Lakes Energy Partners, L.L.C. (Great Lakes), Bank One, NA, JPMorgan Chase Bank, The Bank of Nova Scotia, Bank of Scotland, Credit Lyonnais, New York Branch, Fortis Capital Corp., The Frost National Bank, Union Bank of California, N.A., each Lender (as defined therein), Bank One, NA, as Administrative Agent, JPMorgan Chase Bank, as Syndication Agent, Credit Lyonnais, New York Branch, as Documentation Agent and The Bank of Nova Scotia, as Managing Agent (incorporated by reference to Exhibit 10.4.1 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
10.5.2	First Amendment to Restated Credit Agreement dated April 1, 2003 by and among Great Lakes, Bank One, NA, JPMorgan Chase Bank, The Bank of Nova Scotia, Bank of Scotland, Credit Lyonnais, New York Branch, Fortis Capital Corp., The Frost National Bank, Union Bank of California, N.A., Comerica Bank-Texas, Natexis Banques Populaires, each Lender (as defined therein), Bank One, NA, as Administrative Agent, JPMorgan Chase Bank, as Syndication Agent, Credit Lyonnais, New York Branch, as Co-Documentation Agent, The Bank of Nova Scotia, as Co-Documentation Agent, Banc One Capital Markets, Inc., as Joint Lead Arranger and Bookrunner, and JPMorgan Securities, Inc., as Joint Lead Arranger and Bookrunner (incorporated by reference to Exhibit 10.4.2 to the Company s Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
10.6	Amended and Restated Range Resources Corporation Deferred Compensation Plan for Directors and Select Employees effective September 1, 2000 (incorporated by reference to Exhibit 10.15 to the Company s Form 10-K (File No. 001-12209) as filed with the SEC on March 6, 2001)
10.7.1	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)
10.7.2	Amendment to the Lomak 1989 Stock Option Plan, as amended (incorporated 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)
10.7.3	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)
10.8.1	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)
10.8.2	First Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated June 8, 1995 (incorporated by reference to Exhibit 4.6 to the Company s Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.8.3	Second Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated August 21, 1996 (incorporated by reference to Exhibit 4.7 to the Company s Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.8.4	

Third Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated June 1, 1999 (incorporated by reference to Exhibit 4.8 to the Company s Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)

10.8.5 Fourth Amendment to the Company s 1994 Outside Directors Stock Option Plan dated May 24, 2000 (incorporated by reference to Exhibit 4.9 to the Company s Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)

10.9 Second Amended and Restated 1996 Stock Purchase and Option Plan for Key Employees of Domain Energy Corporation and Affiliates (incorporated by reference to Exhibit 4.1 to the Company s Form S-8 (File No. 333-62439) as filed with the SEC on August 28, 1998)

10.10.1 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)

10.10.2 First Amendment to the Lomak 1997 Stock Purchase Plan dated May 26, 1999 (incorporated by reference to Exhibit 4.2 to the Company s Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)

10.10.3 Second Amendment to the Lomak 1997 Stock Purchase Plan dated September 28, 1999 (incorporated by reference to Exhibit 4.3 to the Company s Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)

10.10.4 Third Amendment to the Company s 1997 Stock Purchase Plan dated May 24, 2000 (incorporated by reference to Exhibit 4.4 to the Company s Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)

10.10.5 Fourth Amendment to the Company s 1997 Stock Purchase Plan dated May 24, 2001 (incorporated by reference to Exhibit 4.7 to the Company s Form S-8 (File No. 333-63764) as filed with the SEC on June 25, 2001)

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Exhibit No.	Description
10.11	Amended and Restated 1999 Stock Option Plan (as amended May 21, 2003) (incorporated by reference to Exhibit 4.1 to the Company s Form S-8 (File No. 333-105895) as filed with the SEC on June 6, 2003)
10.12	Range Resources Corporation 401(k) Plan (incorporated by reference to Exhibit 10.14 to the Company s Form S-4 (File No. 333-108516) as filed with the SEC on September 4, 2003)
10.13	Range Resources Corporation Amended and Restated Change in Control Plan dated September 15, 1998 (incorporated by reference to Exhibit 10.15 to the Company s Form S-4 (File No. 333-108516), as filed with the SEC on September 4, 2003)
14.1**	Code of Ethics
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 the Company Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer of the Company Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification by the President and Chief Executive Officer of the Company Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification by the Chief Financial Officer of the Company Pursuant to 18 U.S.C. Section 350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99**	Audit Committee Charter

* Filed herewith.

** Filed previously.