UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(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, 2002

or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.

For the transition period from _______ to _______

COMMISSION FILE NUMBER 0-9592

RANGE RESOURCES CORPORATION
(Exact name of registrant as specified in its charter)

DELAWARE	34-1312571
(State of incorporation)	(I.R.S. Employer Identification No.)
777 MAIN STREET, FORT WORTH, TEXAS	76102
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code:
(817) 870-2601

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 [X] No [ ]

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

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

Yes [X] No [ ]

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, 2002 was $307,686,000.

As of March 1, 2003, there were 55,339,077 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 2003 Annual Meeting of Stockholders is incorporated by reference in Part III of this Report.

RANGE RESOURCES CORPORATION

ANNUAL REPORT ON FORM 10-K
YEAR-ENDED DECEMBER 31, 2002

PART I

ITEM 1. BUSINESS

GENERAL

Range Resources Corporation (the "Company") is engaged in the development, acquisition and exploration of oil and gas properties, primarily in the Southwestern, Gulf Coast and Appalachian regions of the United States. The Company pursues development drilling, exploitation projects, exploration and acquisitions. The Company's Appalachian assets are held through a 50% interest in a joint venture, Great Lakes Energy Partners L.L.C. ("Great Lakes"). Range's interest in Great Lakes' assets and operations is consolidated in its financial statements. A minor wholly-owned subsidiary, Independent Producer Finance ("IPF"), provides financing to small oil and gas producers through the purchase of overriding royalty interests. At December 31, 2002, the Company had 578 Bcfe of proved reserves, having a pre-tax present value of $965.2 million based on constant prices of $31.17 per barrel and $4.75 per Mmbtu. The fair value of open hedging contracts at December 31, 2002 approximated a loss of $32.9 million. The Company's proved reserves are 76% natural gas by volume, 73% developed and 90% operated. At year-end, the Company had a reserve life index of 10.6 years and owned 676,530 (328,261 net) acres of undeveloped leasehold.

HISTORY

Until 1997, the Company pursued small acquisitions and the further development of its properties, was consistently profitable and steadily increased production and reserves. In 1997 and 1998, several large acquisitions were consummated which proved unsuccessful. Production from the acquired properties fell rapidly and further development proved far less attractive than expected. In combination with the debt burden incurred in the purchases, the adverse impact on the Company's financial results and balance sheet was severe, and the stock price declined significantly. In response, sharp reductions in staff and capital budgets were instituted. Sales of properties and the formation of Great Lakes allowed the Company to substantially reduce debt, but production and reserves fell as a result. In the Great Lakes transaction, Range and FirstEnergy Corp. ("FirstEnergy"), an Ohio-based public utility, contributed their Appalachian assets to a joint venture, forming one of the largest production companies in the region, with Range contributing a disproportionate share of the assets. To achieve equal ownership, the venture assumed $188.3 million of Range's bank debt and FirstEnergy contributed $2.0 million of cash.

To help assure a predictable cash flow, the Company began to aggressively hedge its production as oil and gas prices recovered in late 1999. These hedges covered roughly 80% of anticipated production through the third quarter of 2000. Given the sharp rise in prices during 2000, these hedges limited the benefits of the price increases. Since that time, the Company has continued to hedge a significant percentage of its production on a rolling 12 to 24 month basis. At year-end 2002, hedges were in place on approximately 64.6 Bcf of gas and 1.6 million barrels of oil at average prices of $3.96 per mcf and $24.45 per barrel. These hedges cover approximately 90%, 75% and 10% of anticipated production from proved reserves for 2003, 2004 and 2005, respectively.

With the benefit of rising oil and gas prices and a reduced cost structure, the Company began to increase capital expenditures in 2000, keeping spending below internal cash flow to allow continued pay down of debt. Through debt repayment with cash flow and exchanges of common stock for fixed income securities, debt was steadily reduced. By 2001, the Company was able to increase capital spending sharply to roughly $90.0 million. The benefits of higher energy prices and reduced fixed charges permitted continued profitability and a further reduction of debt. By 2002, leverage had been substantially reduced and the Company was in a position to again pursue long-term growth. Capital spending was increased a further 25% to approximately $112.0 million, including $21.8 million of acquisitions. However, due to continued production declines in the Gulf of Mexico, total Company production declined 2%. The Company's other divisions, Southwest and Appalachia raised production 11% and 4%, respectively, and the Company remained profitable while continuing to reduce debt. While overall production declined slightly in 2002, the benefits of growing capital spending became evident as proved reserves increased 13% and 222% of production was replaced while debt was reduced a further $24.2 million.

The Company has announced a $105.0 million 2003 capital budget excluding acquisitions. The budget includes $89.0 million to drill 326 (173.4 net) wells and 38 (26.9 net) recompletions. A further $12.0 million is budgeted for lease and seismic acquisition and $4.0 million for pipelines and facilities. Based on this level of expenditures, the Company expects to increase production and further expand reserves in the coming year.

DESCRIPTION OF THE BUSINESS

Strategy. Between 1988 and 1997, assets grew one hundred fold to $759.0 million as stockholders' equity increased from less than $1.0 million to $197.0 million. In 1998 and 1999, the Company incurred almost $200.0 million of losses due to disappointing results on several large acquisitions. A series of property impairments, up to and including that recorded in the fourth quarter of 2001, were the primary cause of the losses which materially reduced stockholders' equity. The significant improvement in oil and gas prices since mid-1999 combined with the benefits of reduced costs has allowed the Company to return to profitability in the past three years. Current energy prices in combination with the Company's hedge position, which covers approximately 90% of anticipated 2003 production from proved reserves, is expected to allow the 2003 capital spending to be funded with approximately 75% of internal cash flow.

At year-end, the Company had 2,047 proven 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 while further reducing debt. The Company's 676,530 gross (328,261 net) acres of undeveloped 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 operational and technical experience. At December 31, 2002, the Company had an inventory of 1,770 proven drilling locations and 277 proven recompletions. During 2003, the Company plans to drill 253 proven locations and recomplete 38 wells. In addition, the Company plans to drill more than 40 unproved projects. The following table summarizes 2002 development activity and changes in the inventory of proved development projects:

Development Projects	Recompletion Opportunities	Drilling Locations	Total
Beginning of 2002	274	1,604	1,878
Drilled	(21)	(188)	(209)
Added	40	440	480
Deleted & other	(16)	(86)	(102)
End of 2002	277	1,770	2,047

Exploration. Onshore exploration projects cover 432,483 gross (195,300 net) acres, targeting 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 3.9 million contiguous acres. The Company has offshore leases covering 132,353 (40,740 net) acres on which 13 specific projects have been identified to date. The Company's strategy limits risk by allocating no more than 15% of its capital budget to exploration.

At times, other companies pay all or a disproportionate share of exploration costs to earn an interest. The Company currently expects to participate in as many as 26 exploratory wells in 2003.

Acquisitions. After two years during which the Company withdrew from the market, an acquisition program was reinstated in 2002. The Company will continue to pursue modest purchases in 2003. In 2002, several small acquisitions were completed. The focus is on modest purchases of properties in existing and adjacent fields. To the extent the acquisition effort proves successful, a more substantial effort may be considered.

DEVELOPMENT AND EXPLORATION

In 2002, the Company spent $111.3 million on oil and gas related capital expenditures (Costs incurred - See Note 16 to the financial statements), an increase of 24%, with $56.8 million expended in the Southwest, $34.7 million in Appalachia and $19.8 million in the Gulf Coast. The spending funded 36 (28.1 net) recompletions, 300 (166.4 net) development and 28 (12.2 net) exploratory wells, lease acquisitions and seismic work. Exploration and development spending brought 25.0 Bcfe of proved non-producing reserves on stream and added a net 81.2 Bcfe of new reserves (including acquisitions). Excluding the benefits of price revisions, reserves added during the year replaced 160% of production.

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 oil and gas, generally at depths of less than 8,000 feet. The following table sets forth the development inventory at December 31, 2002 by division:

	Development Projects		
	Recompletion Opportunities	Drilling Locations	Total
Southwest	162	92	254
Gulf Coast	47	13	60
Appalachia	68	1,665	1,733
Total	277	1,770	2,047

Exploration

Onshore. The Company currently has 239 onshore exploration projects covering 432,483 (195,300 net) acres. Most of the projects cover multiple drilling prospects, some with a number of targeted formations. Given the relatively small percentage of the capital budget dedicated to exploration, work on these projects in 2003 will be limited.

Gulf of Mexico. The Company owns a license on a 3-D seismic database covering 780 contiguous blocks in the shallow water of the Gulf of Mexico, primarily offshore Louisiana. In 2001, a joint venture was formed with Callon Petroleum Co. ("Callon") and Cheyenne Petroleum Company ("Cheyenne") to reprocess the data and utilize it to identify and pursue exploration and exploitation opportunities within a 3.9 million acre area. Callon holds a 50% interest in the venture with the Company and Cheyenne each holding 25%. The joint venture was awarded two blocks in the March 2001 OCS lease sale. The Company's current offshore leasehold inventory includes 132,353 gross (40,740 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 46 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.

PRODUCTION

Production revenue is generated through the sale of natural gas, crude oil and natural gas liquids ("NGL") 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 35% of oil and gas revenues in 2002. However, 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 at which 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 basis, 75% of the Company's 2002 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 minor degree, 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. From the inception of Great Lakes through mid 2001, the joint venture sold 90% of its gas production to FirstEnergy. Currently, 92% of Great Lakes gas is sold to a number of parties at prices based on the close of the NYMEX contract each month plus a basis differential. The remainder is sold at a fixed price. 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 purchasers are selected on the basis of price and service. In 2002, gas revenues totaled $144.0

million or 75% of oil and gas revenues while revenues from oil and natural gas liquids totaled $46.9 million. Oil and gas revenues in 2002 decreased 9% from the prior year due to slightly lower production and lower oil and gas prices.

TRANSPORTATION, PROCESSING AND MARKETING

Transportation, processing and marketing revenues are comprised of fees for the transportation and processing of gas as well as oil and gas marketing income. Transportation, processing and marketing revenues were $3.5 million in 2002, roughly level with the prior year. Gas transportation and processing assets include (i) 50% ownership in approximately 4,900 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 systems are charged a fee based on throughput. In the Southwest and Gulf Coast regions, gas production is transported through a combination of Company-owned and third-party gathering systems. The Company is typically charged a fee based on throughput to transport its gas through third-party systems.

The Company markets its own gas production and attempts to reduce the impact of price fluctuations through hedging. Approximately 8% of gas production is currently sold pursuant to fixed price contracts at prices ranging from $1.25 to $5.09 per mcf (averaging $4.35 per mcf). The remaining 92% of gas production is sold at market (generally index) related prices.

HEDGING

The Company regularly enters into hedging agreements to reduce the impact of volatile oil and gas prices. These contracts are entered into solely to hedge prices. The Company's current policy is to hedge between 50% and 75% of its anticipated production, when prices justify it, on a rolling 12 to 24 month basis. Due to the exceptional gas prices in early 2001, the Company extended its hedging into 2005. At December 31, 2002, hedges were in place covering 64.6 Bcf at prices averaging $3.96 per mcf and 1.6 million barrels of oil at prices averaging $24.45 per barrel. Given the significant rise in prices over the past six months, the hedges' fair value, represented by the estimated amount that could be realized on termination, approximated a pre-tax loss of $32.9 million at December 31, 2002. This loss is primarily presented on the balance sheet as a short-term loss of $24.4 million and a long-term loss of $8.5 million. The contracts expire monthly through December 2005 and cover approximately 90%, 75% and 10% of anticipated 2003, 2004 and 2005 production from proved reserves, respectively. Gains or losses on both realized and unrealized hedging transactions are determined as the difference between the contract price and reference price, generally NYMEX. Hedging gains and losses are determined monthly and are included as increases or decreases in oil and gas revenues in the period the hedged production is sold. Changes in the value of the ineffective portion of all open hedges is recognized in earnings quarterly. Pre-tax losses relating to hedging in 2000 and 2001 were $43.2 million and $6.2 million, respectively. A hedging gain of $17.8 million was realized in 2002. Over the last three years, the Company has recorded a cumulative pre-tax hedging loss of $31.6 million. When combined with the $32.9 million unrealized pre-tax loss at year-end 2002, this results in a $64.5 million cumulative loss. Since 2001, 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 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 financial statements).

INDEPENDENT PRODUCER FINANCE ("IPF")

IPF is a minor subsidiary which provides capital to small oil and gas producers in exchange for term overriding royalty interests. The overrides are dollar-denominated and calculated to provide a contractual rate of return that typically exceeds 15%. Interest earned on the overrides is reported as revenues. Almost all of the advances are for less than $5.0 million and most are for less than $2.0 million. Until December 2002, IPF funded its operations through a combination of internal cash flow and bank borrowings. In December 2002, IPF's credit facility was retired with borrowings from the Parent credit facility. At year-end 2002, IPF's portfolio included 34 transactions having an aggregate book value of $24.5 million (net of $12.6 million of valuation allowances). The book value of the portfolio declined 41% in 2002 primarily due to $22.4 million of repayments received during the year and a $4.2 million valuation allowance. The oil and gas reserves underlying IPF's royalties are not included in the Company's reported proved reserves.

IPF provides valuation allowances against advances that may not be recoverable. Increases and decreases in valuation allowances are reported as expenses. IPF expenses also include general and administrative costs and interest expense, which totaled $3.6 million and $2.6 million, respectively, in 2001 and 2002. 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. IPF provides capital to parties who are generally ignored by traditional financial institutions. These producers are typically denied access to financing because: (i) they are too small to access public markets; (ii) private equity and debt financing is too restrictive or unavailable to them; and (iii) few commercial banks are interested in small energy loans. IPF's portfolio declined in 2002 as fundings on existing transactions were more than offset by principal repayments. Since 2001, IPF has not entered into any new financing agreements and does not anticipate entering into any. Therefore, the size of its portfolio should continue to decline.

OTHER

The Company earns interest on cash balances and certain receivables. Other income in 2000 was comprised principally of losses on property sales. The Company expects to continue to sell non-strategic properties. Beginning in 2001, Other income also included ineffective hedging gains or losses. During 2001, $2.3 million of ineffective hedging gains and a $689,000 gain on asset sales was offset by a $1.7 million write-down of marketable securities and a $1.4 million bad debt expense related to Enron hedges. During 2002, $2.7 million of ineffective hedging losses, a $1.2 million write-down of marketable securities and a $715,000 favorable arbitration settlement were recorded. Other income in 2002 amounted to a loss of $2.9 million.

COMPETITION

The Company encounters substantial competition in acquiring oil and gas leases, marketing production, securing personnel and conducting drilling and field operations. Competitors in development, exploration, 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 identify and acquire suitable producing properties and prospects for future drilling.

Historically, acquisitions have generally been financed through the issuance of debt and equity securities and internally generated cash flow. There is competition for capital to finance oil and gas projects. The ability of the Company to obtain financing on satisfactory terms is uncertain and can be affected by numerous factors beyond its control. The inability of the Company to raise external capital in the future could have a material adverse effect on its business.

The Company currently has three issues of fixed income securities outstanding. The 8.75% senior subordinated notes, 6% convertible debentures and 5.75% trust preferred had a combined book value of $175.7 million at December 31, 2002. Their combined fair market value, based on market quotes at that date, was $139.8 million. The Company has, and may continue to, exchange equity for these securities. Such exchanges could have a dilutive effect on shareholders.

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, 9.9 million shares of common stock have been issued in exchange for debt and 5.4 million shares have been exchanged for preferred stock, or a total of 15.2 million shares. The shares were exchanged for $67.2 million face value of 8.75% Senior subordinated notes, 6% Convertible debentures, 5.75% Trust preferred securities and $28.7 million of $2.03

Preferred stock, or a total of $95.8 million. 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 fixed income securities are reacquired. While such exchanges reduce existing stockholders' proportionate ownership, management believes they enhance financial flexibility and will ultimately increase the value of the Company's stock.

The Company believes it has sufficient liquidity and cash flow to meet its obligations. However, a material decline in oil and gas prices or a reduction in production and/or reserves would reduce its ability to fund capital expenditures, meet financial obligations and reduce leverage. In addition, the Company's high depletion depreciation and amortization ("DD&A") rate may make it difficult to remain profitable if oil and gas prices decline sharply.

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 and affects 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 matters in 2002, nor does it anticipate that such expenditures will be material in 2003.

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 liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. Furthermore, although petroleum, including crude oil and natural gas, is exempt from CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as "hazardous substances" under CERCLA and that such wastes may become subject to liability and regulation under CERCLA. State initiatives to further regulate the disposal of oil and gas wastes are pending in certain states and these initiatives could have a significant impact on 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 have 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 reclassify 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.

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" or "targets" and similar expressions that convey the uncertainty of future events or outcomes are intended to identify forward-looking statements. Where any forward-looking statement includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that while we believe these assumptions or bases to be reasonable and to be made in good faith, assumed facts or bases almost always vary from actual results and the difference between assumed facts or bases and the actual results could be material, depending on the circumstances. It is important to note that our actual results could differ materially from those projected by such forward-looking statements. Although we believe that the expectations reflected in such forward-looking statements are reasonable and such forward-looking statements are based upon the best data available at the date this report is filed with the SEC, we cannot assure you that such expectations will prove correct. Factors that could cause our results to differ materially from the results discussed in such forward-looking statements include, but are not limited to, the following: production variance from expectations, volatility of oil and gas prices, hedging results, the need to develop and replace reserves, the substantial capital expenditures required to fund operations, exploration risks, environmental risks, uncertainties about estimates of reserves, competition, litigation, government regulation, political risks, our ability to implement our business strategy, costs and results of drilling new projects, mechanical and other inherent risks associated with oil and gas production, weather, availability of drilling equipment and changes in interest rates. All such forward-looking statements in this document are expressly qualified in their entirety by the cautionary statements in this paragraph, and 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.

Common shareholders will be diluted if additional shares are issued

The Company has filed shelf registration statements that allow it to issue common stock, and the Company has exchanged common stock for its fixed income securities over the past three years. In 2000, 2001 and 2002, the Company exchanged common stock for 5.75% Trust preferred securities, 6% Convertible debentures, 8.75% Senior subordinated notes and $2.03 Convertible preferred stock. The exchanges were made based on the relative market value of the common stock and the convertible securities at the time of the exchange. Negotiated terms in 2002 ranged from a 1% discount to none at a premium and the convertible securities were acquired at discounts to face value ranging from 4% to 41%. During 2000, $25.0 million of Trust preferred, $13.8 million of 6% Convertible debentures and $23.2 million of $2.03 Convertible preferred stock were acquired in exchange for common stock. During 2001, $2.9 million of Trust preferred, $5.7 million of 6% Convertible debentures, $5.4 million of $2.03 Convertible preferred stock and $3.4 million of 8.75% Senior subordinated notes were acquired in exchange for common stock. During 2002, $2.4 million of Trust preferred, $7.1 million of 6% Convertible debentures and $875,000 of 8.75% Senior subordinated notes were acquired in exchange for common stock. Since 1998, $95.8 million face value of convertible securities have been exchanged for 15.2 million shares of common stock. See Notes 6 and 18 to the financial statements. While the exchanges reduce 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 convertible securities for cash is limited by the Parent credit facility and the 8.75% Senior subordinated note agreement. As of December 31, 2002, and March 1, 2003 the Company had only $803,000 and $567,000, respectively available under the 8.75% restricted payments basket. As the restricted payments basket limits the Company's ability to repurchase debt securities at attractive discounts, the Company may seek to amend this agreement. The Company continues to review alternatives to further strengthen its balance sheet and to retire debt and convertible securities.

Dividend restrictions

Restrictions on the payment of dividends and other restricted payments as defined are imposed under the Company's bank credit agreement and the 8.75% Senior subordinated notes. Under the Parent credit facility, common dividends are now permitted. The terms of the 8.75% Senior subordinated 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. Given the Company's losses since the issuance of the 8.75% Senior subordinated notes, the formula provides no availability. Therefore, the Company must rely on the $20.0 million basket. At December 31, 2002, only $803,000 of the $20.0 million basket remained available. With transactions occurring subsequent to December 31, 2002, the basket is $567,000 at March 1, 2003.

Oil and gas prices are volatile, which can adversely affect cash flow

The oil industry is cyclical, and prices for oil and gas are volatile. Historically, the industry has experienced severe downturns characterized by oversupply and/or weak demand. Many factors affect oil and gas prices including general economic conditions, consumer preferences, discretionary spending levels, interest rates and the availability of capital to the industry. In 1998 and early 1999, oil and gas prices fell substantially, which contributed to the substantial losses reported in those years. By early 2001, oil and gas prices reached levels substantially above their historical norm. Prices declined in the second half of 2001 but have risen substantially since mid-2002. Decreases in oil and gas prices from current levels could adversely affect the Company's revenues, net income, cash flow and proved reserves. Significant and prolonged price decreases could have a materially adverse effect on the Company's operations and limit its ability to fund capital expenditures. To help limit this risk, the Company has entered into hedging agreements covering approximately 90% and 75% of its anticipated production from proved reserves for 2003 and 2004, respectively, and a lesser amount of 2005 production. If prices remain above the level at which the hedges were entered into, the hedges will limit the benefit of the price rise.

Hedging activities expose us to certain risks

We enter into hedging arrangements covering a portion of our future production to limit volatility and increase the predictability of cash flow. Hedging instruments are generally fixed price swaps but have at times included or may include collars, puts and options on futures. While hedging limits exposure to adverse price movements, it also limits the benefit of price increases and is subject to a number of risks, including the risk the counterparty to the hedge may not perform. At December 31, 2002, hedges were in place covering 64.6 Bcf and 1.6 million barrels of oil. The hedges' fair value was a loss of $32.9 million. Due to additional hedging activity and rising prices, their fair value on March 1, 2003 had risen to a loss of $108.7 million. If prices continue to rise, the Company could be subject to margin calls.

Estimates of oil and gas reserves may change; we may not replace production

The information on proved oil and gas reserves included in this document are simply estimates. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment,

assumptions used regarding quantities of oil and gas in place, recovery rates and future prices for oil and gas. Actual prices, production, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will vary from those assumed in our estimates, and such variances may be significant. If the assumptions used to estimate reserves later prove incorrect, the actual quantity of reserves and future net cash flow could be materially different from the estimates used herein. In addition, results of drilling, testing and production along with changes in oil and gas prices may result in substantial upward or downward revisions.

In 1997 and 1998, several large acquisitions were consummated which proved extremely disappointing. Production from the acquired properties fell more rapidly than anticipated and further development results were far less attractive than projected in the acquisition engineering. The less than expected performance caused certain downward reserve revisions in 1998. In 1999, a series of exhaustive field performance studies were conducted and the properties re-engineered. The studies included a complete review of 1997 and 1998 capital expenditures and development results, a re-examination of estimates of reservoir thickness, oil and gas in place, ultimate recoverable reserves and the relationship of pressures and production declines to these estimates. Reserve reductions were recorded in 1999, based primarily on performance and a reassessment of the size of the reservoirs offset to a minor degree by upward revisions due to price increases. The 1999 development program in these fields was in part designed to confirm revised engineering forecasts. Downward revisions at year-end 2000 represented the final integration of the field studies, 1999 and 2000 development results, pressure data and production declines. Adjustments at year-end 2000 involved removing from proved reserves drilling and recompletion locations that, based on perceived risk, will probably not be drilled. The downward revision that occurred at year-end 2001 was unlike the previous revisions recorded. Previous revisions were associated with the disappointing performance of the properties acquired in the late 1990s. The entire reserve revision in 2001 was associated with the dramatic reduction in commodity prices during 2001. The impact of the 73% drop in the gas price on the Company's proved reserves, which are 76% gas by volume, resulted in a significant revision. Without the decline in commodity prices, the Company would have experienced a slightly positive performance revision. During 2002, reserves increased 119 Bcfe, including 34 Bcfe related to higher prices and 6 Bcfe due to positive performance revisions. While there can be no assurance that future reserve revisions will not occur, management believes that it has fully assessed all data available through this date.

Without success in exploration, development or acquisitions, our reserves, production and revenues from the sale of oil and gas will decline over time. Exploration, the continuing development of our properties and acquisitions all require significant expenditures and expertise. If cash flow from operations proves insufficient for any reason, we may be unable to fund exploration, development and acquisitions at levels we deem advisable.

Our oil and gas properties' carrying value have been and may in the future be written down

Accounting rules require that the carrying value of oil and 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 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 does not impact cash or cash flow from operating activities, it reduces earnings; increases leverage ratios and reflects the long-term ability to recover a prior investment.

Based primarily on the poor performance of certain properties acquired in 1997 and 1998 and significantly lower oil and gas prices, impairments of $215 million in 1998 and $29.9 million in 1999 were recorded. In 2000, no impairments were required. At year-end 2001, an impairment of $31.1 million was recorded due to year-end prices. No impairments were recorded in 2002. (See Management's Discussion and Analysis - Results of Operations.) For a further discussion of accounting policies related to oil and gas properties, see Note 2 to the Consolidated financial statements.

We could incur substantial environmental liabilities.

The oil industry is subject to numerous federal, state and local laws and regulations relating to the environment. We may incur significant costs and liabilities in complying with existing or future environmental laws and regulations. It is possible that increasingly strict environmental laws, regulations and enforcement policies or claims for damages to property, employees, other persons and the environment resulting from current or discontinued operations, could result in substantial costs and liabilities in the future. For additional information concerning environmental matters, see "Business-Environmental Matters."

Our activities involve operating hazards and uninsured risks

While we maintain insurance against certain of the risks associated with our operations, including, but not limited to, explosion, pollution and fires, an event against which we are not fully insured could have a significant negative effect on our business. Such occurrences could include title defects on properties, lost equipment in drilling operations when the drilling contractor is not responsible for such loss, costs to redrill wells due to down hole equipment and casing failures, and property damage caused over a period of time not covered by standard industry insurance policies.

We maintain insurance in amounts and areas of coverage normal for a company of our size and industry. These include, but are not limited to, workers' compensation, employers' liability, automotive liability and general liability. In addition, umbrella liability and operator's extra expense policies are maintained. All such insurance is subject to normal deductible levels. We do not insure against all risks associated with our business either because insurance is unavailable, or because we elect not to insure due to cost or other considerations.

Individuals or companies who feel the Company or those acting on its behalf damaged them physically or financially, have the right under the law to seek recovery in court. In today's legal climate, the likelihood of suits continues to increase. As verdicts or judgments are so uncertain, the Company may elect to settle claims. Settlements may not be covered by insurance and costs might have to be borne solely by the Company. Even when the Company elects to contest a claim, it may be held liable by the courts. Often, the cost of defending oneself or one's rights cannot be recovered from the other parties even if you prove successful, and the costs must be borne solely by the Company. Such costs and settlements could have a material adverse effect on the Company's financial position. See Item 3 "Legal Proceedings" included in this report and Note 8 to Consolidated financial statements as to certain proceedings and contingencies.

We are subject to financing and interest rate exposure risks

Our business and operating results can be harmed by factors such as the availability and cost of capital, increases in interest rates, changes in the tax rates, market perceptions of the oil and gas industry or the Company, 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, 2002, a portion of the Company's borrowings, held through Great Lakes, were subject to interest rate swap agreements, which are above market, and therefore, increase the Company's interest expense. See Notes 6 and 7 to the financial statements.

We face considerable competition

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

The oil industry is subject to extensive regulation

The oil 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 the regulatory burden. Numerous departments and agencies, both state and federal, are authorized by statute to issue rules and regulations binding on the industry and participants in it. Compliance with such rules and regulations is often difficult and costly and may carry substantial penalties for non-compliance. As the regulatory burden on the industry increases, the cost of complying affects profitability. Generally these burdens do not appear to affect the Company to any greater or lesser extent than other companies in the industry with similar types and quantities of properties in the same areas of the country.

Our high fixed charge burden could impact our liquidity, profitability and cash flow

The Company pays significant interest charges associated with its bank debt, 8.75% Senior subordinated notes, 6% Convertible debentures and 5.75% Trust preferred. The Company's bank debt carries floating interest rates while its other debt securities pay fixed rates. At December 31, 2002, the face value of the Company's fixed rate obligations totaled $175.7 million, and the annual associated interest payments totaled $12.2 million a year. At December 31, 2002, the face value of floating interest rate debt totaled $192.3 million, of which certain amounts held through Great Lakes are effectively fixed through interest swaps. In addition, these debt obligations have certain covenants the Company must meet or comply with to avoid the acceleration of their maturity. See Note 6 to the Consolidated financial statements for their stated maturities. The acceleration of the maturity of one or more of such obligations could have a material adverse effect on the Company.

The Company's significant debt burden could have other important consequences such as, but not limited to, requiring the sale of assets at unfavorable prices, the impact of an increase in interest rates which would increase financing costs and limit capital available for developing and acquiring new properties, limiting the ability to raise capital in the equity and/or debt markets, preclude financing options available to less leveraged companies and make the Company more vulnerable to losses during periods of low oil and gas prices.

Risks associated with IPF

IPF purchases term overriding royalty interests through which it receives an agreed upon share of revenues from certain properties. The producer's obligation to deliver revenues to IPF is non-recourse. Consequently, IPF can only recover its investment and a return through revenues from those properties. These revenues are subject to our ability to estimate reserves and production rates and the operator's ability to produce and recover the projected reserves. In summary, IPF bears the risk that future revenues it receives will be insufficient to amortize the price paid for its overrides or to provide an acceptable return. IPF's production, on a net equivalent barrel basis, is more than 84% oil. Declines in oil prices could cause material increases in the IPF valuation allowance. Many of the existing IPF clients do not have sufficient equity and liquidity to maintain and/or further develop the underlying reserves. If such properties are not fully developed and maintained, the potential reserves applicable to the overriding royalty may not be realizable, requiring periodic valuation allowances to be recognized by IPF.

Acquisitions are subject to numerous risks

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. In 1997 and 1998, a series of acquisitions were consummated which proved unsuccessful. Ongoing results showed the potential of the properties was far less than our engineering and geological review, as well as a review by one of our independent petroleum engineering firms, had suggested.

Our financial statements are complex

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

Our Chairman is affiliated with another oil and gas company that could compete with us

Our Chairman, Thomas J. Edelman, also serves as the Chairman and Chief Executive Officer of Patina Oil & Gas Corporation ("Patina"), a publicly traded oil and gas company in which he is a significant investor. He is also an officer, director and/or significant investor in several other public and private companies engaged in various aspects of the energy industry. We currently have no business relationship with any of these companies, none of them owns our securities, nor do we hold any of theirs. Historically, no material conflict has arisen with regard to these companies. However, conflicts of interests may arise, particularly as Patina has recently become active in some of the same geographic areas as Range. The Board requires Mr. Edelman, along with all other officers and directors, to provide notification of any potential conflicts that arise. All employees of the Company sign a written acknowledgement that they have read and understand the Company's written conflict of interest policy. However, we cannot assure you that we will not compete with one or more of these companies, particularly for acquisitions, or encounter other conflicts of interest in the future.

Success depends on key members of our management

The Company's success is highly dependent on its senior management personnel, of which none are currently subject to an employment contract. The loss of one or more of these individuals could have a material adverse effect on the Company.

WEBSITE

The Company has a website under the name "rangeresources.com". The Company makes available, free of charge, on its website, the annual report on Form 10K, quarterly reports on Form 10Q, current reports on Form 8K and amendments to those reports as soon as practicable after they are electronically filed with or furnished to the SEC.

EMPLOYEES

As of January 1, 2003, the Company had 145 full-time employees, 52 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, 2002, the Company held working interests in 10,671 gross (5,394 net) productive wells and royalty interests in an additional 238 wells. Including its 50% share of Great Lakes' reserves, its properties contained, net to its interest, estimated proved reserves of 440 Bcf of gas and 23 million barrels of oil and NGLs or a total of 578 Bcfe.

PROVED RESERVES

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

	December 31,				
	1998	1999	2000	2001	2002
Natural gas (Mmcf)					
Developed	436,062	299,437	305,796	276,162	320,224
Undeveloped	197,255	144,346	121,871	112,765	120,043
Total	633,317	443,783	427,667	388,927	440,267
Oil and NGL (Mbbls)					
Developed					

19,649
17,884
17,215
14,066
17,176
Undeveloped
7,480
10,933
8,787
6,614
5,776 ----
---- -----
--- ------
-- -------
- --------
Total
27,129
28,817
26,002
20,680
22,952 ---
----- ----
---- -----
--- ------
-- -------
- Total
(Mmcfe)(a)
796,091
616,685
583,679
513,005
577,977
========
========
========
========
======== %
Developed
69.6%
66.0%
70.1%
70.3%
73.2%

(a) Oil and NGL are converted to mcfe at a rate of 6 mcf per barrel.

At year-end 2002, the following independent petroleum consultants evaluated the Company's reserves: H.J. Gruy and Associates, Inc. (Southwest), DeGolyer and MacNaughton (Southwest and Gulf Coast), and Wright and Company, Inc. (Appalachia). These engineers were selected for their geographic expertise and their history in engineering certain properties. At December 31, 2002, these consultants collectively evaluated approximately 84% of the proved reserves. The remaining reserves were evaluated by internal engineering staff. All estimates of oil and gas reserves are subject to significant 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 prices used in projecting them over the past five years (in millions except prices):

	December 31,				
	1998	1999	2000	2001	2002
Future net revenues	$ 1,020	$ 1,013	$ 3,764	$ 750	$ 1,817
Present Value					
Pre-tax	555	556	1,964	399	965
After tax	517	503	1,506	311	500
Oil price (per barrel)	$ 10.26	$ 23.49	$ 24.46	$ 17.59	$ 27.52
Gas price (per mcf)	$ 2.34	$ 2.34	$ 9.57	$ 2.70	$ 4.76

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, 2002. Average product prices at December 31, 2002 were $27.52 per barrel of oil, $18.72 per barrel for natural gas liquids, and $4.76 per mcf of gas using benchmark NYMEX prices of $31.17 per barrel and $4.75 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 areas or divisions known as, Southwest, Gulf Coast and Appalachia. The Appalachian division represents the 50% ownership in Great Lakes. At year-end, the Company's properties included working interests in 10,671 (5,394 net) productive oil and gas wells, royalty interests in an additional 238 wells, and 676,530 (328,261 net) undeveloped acres. The following table sets forth summary information by division with respect to estimated proved reserves at December 31, 2002.

	Pre-tax Present Value		Volumes			
	Amount (In thousands)	%	Oil & NGL (Mbbls)	Natural Gas (Mmcf)	Total (Mmcfe)	%
Southwest	$ 412,685	43	15,552	146,354	239,669	41
Gulf Coast	198,319	20	1,711	75,567	85,830	15
Appalachia	354,147	37	5,689	218,346	252,478	44
Total	$ 965,151	100	22,952	440,267	577,977	100

SOUTHWEST DIVISION

The Southwest Division has 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 43% of the Company's total reserves by value and 41% by volume. Proved reserves in the Southwest Division totaled 239.7 Bcfe, of which 61% was gas. Reserves increased 33.9 Bcfe, up 16% from 2001 due to additions, higher commodity prices and favorable performance revisions. The region's daily production totaled 71.5 Mmcfe per day, representing 48% of total production. On an annual basis, production increased 11% from 2001. At year-end, the Southwest Division had an inventory of 162 proven recompletions and 92 proven drilling locations. Acreage owned in the region at that date included 198,554 (149,448 net) developed acres and 160,749 (120,442 net) undeveloped acres. During 2002, 72 (64.9 net) development wells were drilled in the region, of which 69 (62.3 net) were productive and 6 exploratory wells (6.0 net) were drilled, of which 3 (3.0 net) were productive. During the year, the region achieved a 92% drilling success rate.

In East Texas, 4 (3.3 net) successful wells were drilled at the Laura LaVelle field in Houston County, Texas. Net production from the field currently approximates 2.9 Mmcfe a day. In other East Texas drilling, one (1.0 net) well was drilled in the James Lime formation, a fractured carbonate. The well was successfully completed at an initial rate of 4 (3.2 net) Mmcfe per day but declined rapidly to 0.5 Mmcfe per day. Also in East Texas, the Company successfully drilled two Travis Peak wells (the Linder #2 & #3) in Henderson County, Texas. These wells were completed at depths ranging from 9,491 to 9,550 feet. In West Texas, 15 (13.8 net) infill and field extension wells were successfully drilled in 2002 in the Sterling Field of Sterling County, Texas. Net production from this field currently approximates 14.1 Mmcfe per day. In the Val Verde field of Edwards and Sutton Counties, Texas, 5 (2.8 net) infill and field extension wells were drilled and completed. There were also 8 (8.0 net) Val Verde field wells recompleted in 2002. At year-end the net production from this field approximates a net 8.3 Mmcfe per day.

In West Texas, 16 (15.6 net) wells were drilled in the Fuhrman - Mascho field complex. Of the 16 wells, four were water injection wells in a waterflood development pilot. At year-end, the Fuhrman Mascho field area was producing approximately 5.6 mcfe per day. The Company expects to continue the drilling program in 2003. In West Texas, three wells were also successfully drilled at Powell Ranch in Glasscock, County. At year-end, production from that field totaled 11.1 net Mmcfe per day.

In the Texas Panhandle, the Morrow play continues to provide growth opportunities. Characterized by multiple sands and depositional environments within a single formation, the Upper, Middle and Lower Morrow Sands produce at depths of 7,000 to 12,000 feet with average expected reserves of 1.5 Bcf and individual wells ranging from 1 to 5 Bcfe. Range currently holds more than 62,000 (49,500 net) acres in the play. Traditionally, the Morrow has been a statistical play. With the aid of 307 square miles of 3-D seismic and regional subsurface mapping, the Company believes its geoscientists are now able to identify promising opportunities and increase the predictability of drilling. In 2002, Range drilled a total of 11 (10.1 net) Morrow wells with a 73% success rate. The 8 (7.7 net) successful wells drilled in 2002 are currently producing at a rate of 8.8 (6.5 net) Mmcfe per day. Each new well has enhanced the ability to interpret key seismic reflectors. Significant wells drilled in the area in 2002 were the Pioneer #2, the Intrepid #1-107, and the Courson Ranch #1-140. The Pioneer #2 in the Ben Hill area of northeast Roberts County tested over 8.3 (6.6 net) Mmcfe per day from the targeted Lower Morrow Sand and after 11 months of production is currently delivering in excess of 3.1 (2.5 net) Mmcfe per day. The Courson Ranch #1-140 in northwest Roberts County was initially tested at rates exceeding 1,000 (546 net) bbls of oil per day in the Upper Morrow Sand. The well is currently producing at the full allowable rates of 340 (186 net) bbls of oil per day and 0.3 (0.2) Mmcf per day. Since first sales in late October 2002, the well has produced 25,000 bbls of oil and 22 Mmcf of gas.

In the Anadarko Basin, 8 (5.4 net) wells were drilled in the Sooner, Watonga-Chickasha, Granite Wash and Northwest Shelf trends during 2002. The notable success in the Watonga-Chickasha was the Endeavour #1-28, which completed in the Morrow/Springer sands and tested in excess of 1.2 (0.9 net) Mmcfe per day. The Watonga-Chickasha area was also the location of certain minor property purchases, in 2002, with 14 (8.0 net) wells being acquired in the area. Production associated with the acquired properties approximated 2.3 Mmcfe per day. Included in the transactions were 8,000 (5,252 net) acres of leasehold which provide new drilling opportunities.

GULF COAST DIVISION

The Gulf Coast Division represents 20% of reserves by value and 15% by volume. Proved reserves totaled 85.8 Bcfe, down 10% in 2002. During the year, the region only partially replaced production, which totaled 16.3 Bcfe. Gulf Coast reserves are 88% 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 Gulf Coast represented 30% of the Company 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 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. Offshore properties include interests in 40 platforms in water depths ranging from 20 to 210 feet, none of which are operated. The Gulf Coast's development inventory includes 47 recompletions and 13 drilling locations on 139,026 (45,480 net) developed acres and 75,439 (16,826 net) undeveloped acres.

In 2002, the region spent $19.0 million to drill 8 (2.3 net) wells, recomplete 7 (2.2 net) others and to upgrade facilities. In the fourth quarter of 2002, net production averaged 674 barrels of oil and 36,349 Mmcf of gas per day or 40,396 Mmcfe per day in total. Production during the year declined 20% to 44.7 Mmcfe per day due to the natural decline on mature properties. During 2002, four development wells (1.2 net) were drilled, all of which were productive. Four exploratory wells (1.1 net) were drilled, all of which were productive.

Offshore, the joint venture formed between Range, Callon and Cheyenne continued to explore the central shelf of the Gulf of Mexico, successfully drilling its first exploratory well, the Ship Shoal 28 #40. The well was drilled to a measured depth of 15,327 feet, encountering 140 feet of net gas pay. Range has a 26.8% WI (NRI varies by zone from 19.6% to 21.8%). The well tested at

rates as high as 12 (2.4 net) Mmcf per day and is scheduled to go on production
in

May. To date, the joint venture has spent $2.1 million on additional seismic data. The joint venture increased its total 3-D seismic data coverage from 5,500 square miles to 6,100 square miles in 2002 and the joint technical team continued working the data, identifying 22 new leads and bringing the total number of identified prospects to 46.

Outside of the joint venture, Range used its offshore seismic database to identify two prospects on existing acreage and caused wells to be drilled on them in 2002. The most notable was the West Cameron 45 #20 well, which was drilled to 16,444 feet encountering 59 feet of net gas pay sand. The well was turned on in mid-December and is currently producing in excess of 30 Mmcf (6.0 net) per day. In August 2002, Range participated in a well on Vermilion Block 332. This shallow test, in which Range owns a 16.5% WI (11.6% NRI), was drilled to a depth of 3,184 feet and encountered gas in two horizons. Plans are to produce the bottom zone first. The combined test rate for both zones was 12.3 Mmcf per day (1.4 net). First sales are anticipated in March. Range is continuing to work the data covering existing fields to generate additional prospects.

Onshore, Range participated in the drilling of four wells in 2002. The most significant was the Arceneaux #1 well in Vermilion Parish, Louisiana. This Range-operated 11,939-foot test of the Upper Oligocene Marg howei sand began producing in late August. The well has already produced more than 1.0 Bcf and is flowing in excess of 6.3 Mmcf (2.0 net) per day. A nearby test well, the Faulk #1, is expected to be spud before the end of the first quarter. Range also drilled two wells in the shallow water of Galveston Bay to produce attic oil and gas accumulations. The ST 127 #1 encountered 95 net feet of Upper Frio oil and gas pay. The well began producing in late March 2002 and is currently flowing 2.3 Mmcf (0.4 net) and 157 barrels (25 net) per day. The ST 127 #2 was drilled to a different fault block and then sidetracked to a more advantageous position. After three months of production, the well developed a mechanical problems and Range elected not to participate in attempts to restore production.

APPALACHIAN DIVISION

Through its 50% interest in Great Lakes, the Appalachian Division represents 252.5 Bcfe of proved reserves, or 44% by volume and 37% by value of total proved reserves. The region has an interest in 9,047 gross (3,914 net) wells and 4,900 miles of gas gathering lines. Great Lakes sells its gas on a negotiated basis to a number of companies. At December 31, 2002, Great Lakes had an inventory of 68 proven recompletions and 1,665 proven drilling locations.

Development Projects	Recompletion Opportunities	Drilling Locations	Total
Beginning of 2002	51	1,468	1,519
Drilled	(5)	(160)	(165)
Added	22	431	453
Deleted	--	(74)	(74)
End of 2002	68	1,665	1,733

Acreage owned in the Appalachian region at December 31, 2002 included 689,895 (327,111 net) developed acres and 440,342 (190,993 net) undeveloped acres. During 2002, 224 (100.3 net) development wells were drilled, of which 221 (98.8 net) were productive. Eighteen (5.1 net) exploratory wells were drilled, of which 10 (2.8 net) were productive. At December 31, 2002, Great Lakes operated 99% of its wells. The reserves are 86% gas and produce principally from the upper-Devonian, Medina, Clinton, Knox and Oriskany formations at depths ranging from 2,500 to 7,000 feet. In the fourth quarter of 2002, net production averaged 28.9 Mmcf of gas and 845 barrels of oil, or a total of 34.0 Mmcfe per day. The Division's properties, with 1,733 proven projects at year-end, are located in the Appalachian and, to a minor degree, 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 2002, $20.8 million in capital funded the drilling of 217 (97.3 net) shallow development wells and 25 (8.1 net) medium depth wells. In addition, capital was expended on 5 (2.2 net) recompletions as well as the purchase of 825 miles of 2-D and 3-D seismic data and 167,012 (70,315 net) acres of leasehold. Of the 224 development wells drilled, 221 were successful. Ten of the 18 exploration wells were also successful, indicating an overall 96% success rate. Production during the year averaged 33.9 Mmcfe per day net, a 4% increase. Year-end proved reserves increased approximately 19% to 252.5 Bcfe primarily as a result of higher commodity prices, acquisitions and additions.

During 2002, exploration prospects at Great Lakes included targets in the Knox Unconformity, Huntersville-Oriskany and Trenton Black River plays. The largest effort (20 (6.2 net)) was directed to the Knox play in Ohio. Great Lakes significantly increased its use of 3-D seismic in the Knox play, shooting or acquiring over 30 square miles of data in three separate areas. Each of these shoots yielded discovery wells with additional drilling opportunities. Great Lakes also shot a moderate amount of 2-D seismic and drilled 2 (1.0 net) wells in the Huntersville/Oriskany play in Pennsylvania. While both wells were successfully completed, initial production rates have been below expectations. In the Trenton Black River play, leases on over 125,000 gross acres in four major prospect areas were acquired, and seismic and drilling work is planned for 2003. All 3 (0.6 net) wells drilled in 2001 to the Trenton Black River were unsuccessful.

Five major geologic plays comprise Great Lakes' exploration and development portfolio. The two major development plays, consisting primarily of shallow low-risk, lower impact wells include the Clinton Medina and Upper Devonian Sandstone. Production from these shallower blanket-type, tight-sand formations is characteristically long-lived with estimated ultimate production of from 150 to 750 Mmcf per well. The three exploration plays, consisting of medium to deep wells with higher-risk and higher potential impact, include the Knox Unconformity, the Huntersville/Oriskany Sandstone and the Trenton Black River. Wells drilled in the Knox Unconformity are characterized by a shorter well life of 10 years or less and have reserves in the 250 Mmcf to 1 Bcf range. Production from the deeper and more structurally complex formations such as the Oriskany is in the 500 Mmcf to 3 Bcf range with a 15-25 year well life or greater. Recent discoveries by other operators in the fault-related Trenton Black River play indicate per well recoveries in the 500 Mmcf to 5 Bcf range, particularly in the deeper structures.

Management of Great Lakes is overseen by a management committee comprised of three representatives from the Company and three from FirstEnergy.

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,				
	1998	1999	2000	2001	2002
Production					
Gas (Mmcf)	45,193	50,808	41,039	42,278	41,096
Crude oil (Mbbl)	2,175	2,247	2,035	1,916	1,873
Natural gas liquids (Mbbl)	480	412	363	326	407
Total (Mmcfe) (a)	61,123	66,762	55,427	55,730	54,772
Revenues					
Gas	$105,509	$108,115	$118,977	$154,175	$144,030
Crude oil	26,119	33,075	47,414	49,033	41,665
Natural gas					

liquids 3,965
4,302 6,691
5,646 5,259
Transportation
and
processing
6,711 7,770
5,306 3,435
3,495 -------
- -------- --
------ ------
-- --------
Total 142,304
153,262
178,388
212,289
194,449
Direct
operating
expenses (b)
39,001 43,074
40,552 43,430
40,443 ------
-- -------- -
------- -----
--- --------
Gross margin
$103,303
$110,188
$137,836
$168,859
$154,006
========
========
========
========
========
Average sales
price (c) Gas
(mcf) $ 2.33
$ 2.13 $ 2.90
$ 3.65 $ 3.50
Crude oil
(bbl) 12.01
14.72 23.30
25.59 22.26
Natural gas
liquids (bbl)
8.26 10.44
18.43 17.33
12.93 Mcfe
(a) (d) 2.22
2.18 3.12
3.75 3.49
Operating
costs (mcfe)
Direct $ 0.57
$ 0.58 $ 0.62
$ 0.63 $ 0.59
Severance and
production
taxes 0.07
0.07 0.11
0.15 0.15 ---
----- -------
- -------- --
------ ------
-- Total $
0.64 $ 0.65 $
0.73 $ 0.78 $
0.74 ========
========
========
========
========

(a) Oil and NGL are converted to mcfe at a rate of 6 mcf per barrel.

(b) Includes severance and production taxes.

(c) Average sales prices are net of hedging, which increased average oil prices in 2001 by $2.21 a barrel and reduced average oil prices by $1.09 a barrel in 2002. Hedging decreased average gas prices by $0.25 per mcf and increased average gas prices by $0.48 per mcf in 2001 and 2002, respectively. Average NYMEX gas prices were $2.51 and $3.24 in 2001 and 2002, respectively. Average NYMEX oil prices were $19.40 and $26.08 in those same time periods.

(d) Average prices realized excluding hedging were $3.90, $3.86 and $3.16 per mcfe, in 2000, 2001 and 2002, respectively.

PRODUCING WELLS

The following table sets forth information (including the Company's 50% share of Great Lakes) relating to productive wells at December 31, 2002. The Company owns royalty interests in an additional 238 wells. Wells are classified as oil or gas according to their predominant production stream.

	Wells		Average Working Interest
	Gross	Net	
Crude oil	1,620	1,119	69%
Natural gas	9,289	4,276	46%
Total	10,909	5,395	49%

ACREAGE

The following table sets forth acreage held at December 31, 2002.

	Acres		Average Working Interest
	Gross	Net	
Developed	1,027,475	522,039	51%
Undeveloped	676,530	328,261	49%
Total	1,704,005	850,300	50%

The following table sets forth, for the preceding three years, the book value of unproved acreage by division (in thousands).

	December 31,		
	2000	2001	2002
Southwest			

	$ 38,815	$ 20,906	$ 14,768
Gulf Coast	9,103	3,081	2,226
Appalachian	1,605	1,743	2,072
Total	$ 49,523	$ 25,730	$ 19,066

DRILLING RESULTS

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

	2000		2001		2002	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	173.0	82.5	256.0	112.9	294.0	162.3
Dry	6.0	4.4	8.0	5.5	6.0	4.1
Exploratory wells						
Productive	9.0	2.9	6.0	1.9	17.0	6.9
Dry	7.0	1.7	2.0	0.9	11.0	5.3
Total wells						
Productive	182.0	85.4	262.0	114.8	311.0	169.2
Dry	13.0	6.1	10.0	6.4	17.0	9.4
Total	195.0	91.5	272.0	121.2	328.0	178.6

=====
=====
=====
=====
=====
Success
ratio 93%
93% 96%
95% 95%
95%

REAL PROPERTY

The Company leases approximately 59,000 square feet of office space 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. During 2002, approximately $250,000 of costs were expensed in defense of litigation and $385,000 reduced an accrued liability related to the period prior to the formation of Great Lakes. The Company received a $715,000 arbitration recovery, net of $72,000 of legal expenses. In the opinion of management, such litigation 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 2002.

PART II

ITEM 5. MARKET FOR COMMON STOCK AND RELATED MATTERS

The Company's common stock is listed on New York Stock Exchange ("NYSE") under the symbol "RRC." During 2002, trading volume averaged 142,554 shares per day. On March 1, 2003, the closing price of the common stock was $5.93. 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
2001			
First quarter	$ 7.13	$ 5.15	374,390
Second quarter	6.68	4.90	392,240
Third quarter	6.20	4.25	353,008
Fourth quarter	4.76	3.93	240,491
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

Between January 1, 2003 and March 1, 2003, the common stock traded at prices between $5.20 and $6.20 per share. The Company's 5.75% Trust preferred, 6% Convertible debentures and 8.75% Senior subordinated notes are not listed on an exchange, but trade over the counter.

At various times in 2002, the Company issued common stock in exchange for fixed income 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 in 2000, 2001 and 2002:

	Face Amount ($000)			Common Stock Issued (000's)		
Security Exchanged	2000	2001	2002	2000	2001	2002
8.75% Subordinated Notes	$ --	$ 3,385	$ 875	--	754	175
6% Debentures	13,810	5,710	7,140	2,448	745	1,150
5.75% Trust preferred	25,029	2,850	2,400	3,231	291	283
$2.03 Preferred stock	23,246	5,425	--	4,584	767	--
	$62,085	$17,370	$10,415	10,263	2,557	1,608
Market value at date of exchange	$36,910	$14,027	$ 8,242			

HOLDERS OF RECORD

At March 1, 2003, there were approximately 2,308 holders of record of the common stock.

DIVIDENDS

Quarterly common stock dividends were initiated in 1995. In connection with the Company's need to reduce leverage, the dividend was reduced in the first quarter and eliminated in the fourth quarter of 1999. The Parent bank facility and the 8.75% Senior subordinated notes contain restrictions on the payment of dividends. Since January 1, 2003, the Parent bank facility has permitted dividends. Under the 8.75% senior subordinated notes, the Company may pay restrictive payments, including dividends, equal to the greater of: i) $20.0 million or ii) a formula which includes earnings and losses since the issuance of the notes. Given its losses since 1997, the Company cannot make payments under the formula and must rely on the $20.0 million basket. At December 31, 2002, only $803,000 remained available under the basket. The Company may seek to amend this covenant.

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	3,448,644(b)	$ 4.46	3,767,192(b)

(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. 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) Includes 167,000 shares related to the stock purchase plan for which there is no prescribed price.

ITEM 6. SELECTED FINANCIAL DATA

The following table presents selected financial information covering the last five years.

As of or for the Year-Ended December 31,	1998	1999	2000	2001	2002
(In thousands, except per share data)					
OPERATIONS					
Revenues	$ 148,929	$ 193,047	$184,828	$219,425	$ 195,338
Net income (loss)	(181,273)	(23,542)	36,578	17,663	25,766
Earnings (loss) per share Before extraordinary gain -Basic	(7.11)	(0.78)	0.55	0.28	0.45
-Diluted	(7.11)	(0.78)	0.54	0.28	0.44
After extraordinary gain -Basic	(7.11)	(0.71)	0.97	0.36	0.49
-Diluted	(7.11)	(0.71)	0.96	0.36	0.47
Dividends per share	0.12	0.03	--	--	--
BALANCE SHEET					
Working capital (deficit) (a)	$ (8,198)	$ 20,011	$ 9,665	$ 29,856	$ (29,852)
Oil and gas properties,					

net 653,260
570,643
553,173
533,357
564,406
Total assets
913,970
732,228
671,826
682,462
658,484
Senior debt
367,062
140,000
89,900
95,000
115,800 Non-
recourse
debt 60,100
142,520
113,009
98,801
76,500
Subordinated
debt 180,000
176,360
162,550
108,690
90,901 Trust
preferred
120,000
117,669
92,640
89,740
84,840
Stockholders'
equity (b)
125,669
103,238
159,944
235,621
206,109

a) Refer to Company's detailed balance sheet for hedging amounts included herein.

b) Stockholders' equity includes other comprehensive income (loss) of $292,000, $189,000, $(639,000), $45.5 million and $(21.2 million) in 1998, 1999, 2000, 2001 and 2002, respectively.

The following table sets forth summary unaudited financial information on a quarterly basis for the two years ended December 31, 2002 (in thousands, except per share data).

2001	March 31	June 30	September 30	December 31	Total
Revenues	$ 63,105	$ 58,445	$ 52,143	$ 45,732	$ 219,425
Net income (a)	20,053	16,968	8,198	(27,556)	17,663
Earnings per share -basic	0.42	0.34	0.16	(0.54)	0.36
-diluted	0.41	0.33	0.16	(0.54)	0.36
Total assets	658,825	695,418	584,373	682,462	682,462
Senior debt	76,800	88,800	95,000	95,000	95,000
Non-recourse debt	98,006	99,902	102,501	98,801	98,801
Subordinated debt	160,940	133,340	121,840	108,690	108,690
Trust preferred	92,640	90,290	90,290	89,740	89,740
Stockholders' equity	151,136	222,064	247,635	235,621	235,621

2002	March 31	June 30	September 30	December 31	Total
Revenues	$ 44,219	$ 49,307	$ 50,337	$ 51,475	$ 195,338
Net income (b)	4,341	7,310	9,222	4,893	25,766
Earnings per share -basic	0.08	0.14	0.17	0.09	0.49
-diluted	0.08	0.13	0.17	0.09	0.47
Total assets	644,502	640,222	637,901	658,485	658,484
Senior debt	99,600	98,300	101,600	115,800	115,800
Non-recourse debt	95,100	92,000	87,100	76,500	76,500
Subordinated debt	106,300	95,691	91,206	90,901	90,901
Trust preferred	87,340	87,340	84,840	84,840	84,840
Stockholders' equity	216,221	220,639	217,586	206,111	206,109

(a) Includes extraordinary gains on retirement of securities of $432,000 in the first quarter. These gains were $895,000 and $319,000 in the second and third quarters (net of taxes), respectively. In the fourth quarter of 2001, the gain on retirement of securities was $2.3 million (net of taxes). The fourth quarter includes an impairment charge of $31.1 million.

(b) Includes extraordinary gains (net of taxes) of $770,000, $545,000, $687,000 and $12,000 in the first, second, third and fourth quarters, respectively.

The total of quarterly earnings per share does not necessarily equal the earnings per share for the year, either because the calculations are based on the weighted average shares outstanding or rounding. During the fourth quarter of 2001, the Company recorded $31.1 million of impairments. (See Management's Discussion and Analysis - Results of Operations.)

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.)

RESTATEMENT

For many years, Arthur Andersen LLP served as the Company's auditor. In July 2002, the Company selected KPMG LLP as its new independent auditor. Simultaneously, the Company asked KPMG to reaudit its consolidated financial statements for the three years ended December 31, 2001, even though a reaudit was not required. The reaudit was intended to provide additional assurance to shareholders, ensure the Company's ongoing access to the capital markets and to avoid any possible impediment to future transactions. As a result of the reaudit, the financial statements were restated. For the three years ended December 31, 2001, the cumulative impact of the restatements reduced net income by $8.4 million, of which $7.8 million related to the reduction of the gain associated with the formation of Great Lakes in 1999. The restatement increased the 1999 net loss by $15.7 million, reduced 2000 net income by $1.4 million, increased 2001 net income by $8.7 million and reduced first half of 2002 net income by $2.3 million.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Company's discussion and analysis of its financial condition and results of operation 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 reported amounts of assets, liabilities, revenues and expenses. 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, 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 affect its more significant judgments and estimates used in the preparation of its financial statements.

Proved reserves - 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. Reserves estimates are updated at least annually and consider recent production levels and other technical information about each well. 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 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.

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 Footnote 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.

Successful efforts accounting - 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 developed oil and gas reserves as estimated by the Company's engineers. The Company also uses proved developed reserves as the divisor to accrue the expense of estimated future dismantlement and abandonment costs. At year-end, the Company had a liability totaling $32.1 million for plugging and abandonment costs on its balance sheet. This liability is shown netted against oil and gas properties on the balance sheet. Currently, the Company's estimates it will spend $13.2 million over the next three years on plugging and abandonment costs. The Company will adopt SFAS 143 on January 1, 2003 which changes the accounting treatment for these types of costs. See Note 2 to the Consolidated financial statements "Recent Accounting Pronouncements" for further discussion.

Impairment of properties - The Company continually 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, 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, 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.

Income taxes - The Company is subject to income and other similar 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 carryforwards 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.

The Company's deferred tax assets exceeded its deferred tax liabilities at year-end 2001 before considering the effects of Other comprehensive income (loss) ("OCI"). In determining deferred tax liabilities, accounting rules require OCI to be considered, even though such income (loss) has not yet been earned. The inclusion of OCI caused deferred tax liabilities to exceed deferred tax assets by $4.5 million at year-end 2001 and this amount was recorded as a deferred tax liability on the balance sheet. At year-end 2002, deferred tax assets exceeded deferred tax liabilities by $15.8 million with $11.4 million of deferred tax assets related to deferred hedging losses included in OCI. Based on the Company's projected profitability, no valuation allowance was deemed necessary.

The Company occasionally 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.

Legal, environmental and other contingent matters - 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 an interpretation of laws and regulations, which can be interpreted differently by regulators and/or the courts. Management closely 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.

Other significant accounting policies requiring estimates include the following: The Company recognizes revenues from the sale of products and services in the period delivered. Revenues at IPF are recognized as earned. We provide an allowance for doubtful accounts for specific receivables we judge unlikely to be collected. At IPF, all 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. The Company records a write down of marketable securities when the decline in market value is considered to be other than temporary. Changes in the value of the ineffective portion of all open hedges is recognized in earnings quarterly. The fair value of open hedging contracts is an estimated amount that could be realized upon termination. The Company stock held in the deferred compensation plan is treated as treasury stock and the carrying value of the deferred compensation is adjusted to fair value each reporting period by a charge or credit to operations in general and administrative expense.

FACTORS AFFECTING FINANCIAL CONDITION AND LIQUIDITY

LIQUIDITY AND CAPITAL RESOURCES

During 2002, the Company spent $111.3 million on development, exploration and acquisitions. Fixed income obligations including Trust preferred were reduced by $24.2 million. At December 31, 2002, the Company had $1.3 million in cash, total assets of $658.5 million and a debt (including Trust preferred) to capitalization (including debt, deferred taxes and stockholders' equity) ratio of 64%. Available borrowing capacity on the Company's bank lines at December 31, 2002 was $31.1 million on the Parent credit facility and $52.0 million at Great Lakes (of which $26.0 million was net to Range). Long-term debt (including Trust preferred) at December 31, 2002 totaled $368.0 million and included $115.8 million of borrowings under the Parent credit facility, $76.5 million under the non-recourse Great Lakes facility, $69.3 million of 8.75% Senior subordinated notes, $21.6 million of 6% Convertible subordinated debentures and $84.8 million of Trust preferred. At December 31, 2002, the Company had a working capital deficit of $29.8 million which included a net hedging liability of $26.0 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, the amount should be self funding.

During 2002, 1.6 million shares of common stock were exchanged for $2.4 million of Trust preferred, $875,000 of 8.75% Senior subordinated notes and $7.1 million of 6% Debentures. In addition, $815,000 of 6% Debentures, $9.0 million of 8.75% Senior subordinated notes and $2.5 million of 5.75% Trust preferred were repurchased for cash. A $3.1 million extraordinary gain ($2.0 million after tax) was recorded, as the securities were retired at a discount. Since 1998, 15.2 million shares of common stock have been exchanged for $95.8 million face value of debt and convertible preferred stock.

The Company believes its capital resources are adequate to meet its requirements for at least the next 12 months. However, future 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 and meet financial obligations. In addition, the Company's high depletion, depreciation and amortization rate may make it difficult to remain profitable if oil and gas prices decline substantially. The Company operates in an environment with numerous financial and operating risks, including, but not limited to, the ability to acquire reserves on an attractive basis, the inherent risks of the search for, development and production of oil and gas, the ability to 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 planned capital expenditures.

The following summarizes the Company's contractual financial obligations at December 31, 2002 and their future maturities (in thousands):

	Less than 1 Year	1 - 3 Years	After 3 Years	Total
Long-term debt	$ --	$192,300(a)	$175,741	$368,041
Non-cancelable operating lease obligations	1,808	2,663	299	4,770

--- ------
-- -------
- Total
contractual
cash
obligations
$ 1,808
$194,963
$176,040
$372,811
========
========
========
========

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

Total long-term debt (including Trust preferred) at December 31, 2002, was $368.0 million. Long-term debt of $192.3 million was subject to floating interest rates (of which certain amounts have interest swap agreements) and $175.7 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
8.75% Sr. sub. notes	$ 69,281	$ 6,062	January, July	2007
6% Debentures	21,620	1,297	February, August	2007
5.75% Trust preferred	84,840	4,878	Feb., May, Aug., Nov.	2027
	$175,741	$ 12,237		

Cash Flow

The Company's principal sources of cash are operating cash flow and bank borrowings. The Company's cash flow is highly dependent on oil and gas prices. The Company has entered into hedging agreements covering approximately 90%, 75% and 10% of its anticipated production from proved reserves for 2003, 2004 and 2005, respectively. Decreases in prices and lower production at certain properties reduced cash flow sharply in 1998 and 1999 and resulted in a reduction of the Company's borrowing base. Simultaneously, the Company sharply reduced its development and exploration spending. The $111.9 million of capital expenditures for 2002, excluding acquisitions was funded with internal cash flow. The amount expended replaced 222% of production. In the absence of price revisions, net reserves added during the year replaced 160% of production. The $105.0 million 2003 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 2003 capital program is expected to be funded with approximately 75% of internal cash flow.

Net cash provided by operations in 2000, 2001 and 2002 was $74.9 million, $129.6 million, and $109.2 million respectively. In 2001, cash flow from operations increased as higher prices and lower interest expense more than offset increasing operating and exploration expenses. In 2002, cash flow from operations decreased with lower prices and volumes, higher exploration and general and administrative costs, somewhat offset by lower interest and direct operating costs.

Net cash used in investing in 2000, 2001 and 2002 was $6.0 million, $78.2 million and $98.7 million respectively. In 2000, $47.5 million of additions to oil and gas properties were offset by $25.9 million proceeds from sales of assets and $24.8 million of IPF repayments. The 2001 period included $87.0 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. The 2002 period included $109.1 million of additions to oil and gas properties and $5.1 million of IPF investments partially offset by $17.3 million of IPF receipts. Net cash used in financing (to repay debt) in 2000, 2001 and 2002 was $79.3 million, $50.6 million and $12.6 million respectively. Historically, sources of financing have been primarily bank borrowings and capital raised through equity and debt offerings. During 2000, recourse debt decreased $45.1 million and total debt (including Trust preferred) decreased $113.5 million. The reduction in debt was the result of applying excess internal cash flow and proceeds from asset sales to debt repayment and exchanges of common stock for fixed income securities. During 2001, recourse debt increased by $5.1 million and total debt (including Trust preferred) 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 fixed income securities. During 2002, recourse debt increased $20.8 million and total debt (including Trust preferred) decreased by $24.2 million. Recourse debt increased due to the retirement of the IPF credit facility and the repurchase of fixed income securities with borrowing under the Parent credit facility.

Capital Requirements

During 2002, $111.9 million of capital was expended, primarily on development projects. The capital program, excluding acquisitions, was funded with approximately 83% of net cash flow from operations. The Company manages its capital budget with the goal of fully funding it with internal cash flow. The 2003 capital budget of $105.0 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. See "Business--Development and Exploration Activities."

Banking

The Company maintains two separate revolving credit facilities, a $225.0 million Parent facility and a $275.0 million Great Lakes facility (of which 50% is consolidated at Range). In December 2002, the IPF credit facility was retired with borrowings under the Parent credit facility. Each facility is secured by substantially all of the assets of the borrower. The Great Lakes facility is non-recourse to Range. As Great Lakes is 50% owned, half of its borrowings are consolidated in Range'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 require approval of 75% of the lenders, increases require unanimous approval. At March 1, 2003, a $147.0 million borrowing base was in effect at Range of which $23.5 million was available and a $205.0 million borrowing base was in effect at Great Lakes, of which $44.0 million was available.

HEDGING

Oil and Gas Prices

The Company regularly enters into hedging agreements to reduce the impact of oil and gas price fluctuations on its operations. The Company's current policy, when futures prices justify, is to hedge between 50% and 75% of projected production on a rolling 12 to 24 month basis. At December 31, 2002, hedges were in place covering 64.6 Bcf of gas at prices averaging $3.96 per mcf and 1.6 million barrels of oil at prices averaging $24.45 per barrel. The hedges fair value, represented by the estimated amount that would be realized or payable on termination, based on contract versus NYMEX prices, approximated a pretax loss of $32.9 million at December 31, 2002. The contracts expire monthly through December 2005 and cover approximately 90% of anticipated 2003 production from proved reserves, 75% of 2004 production and a minor amount of 2005 production. Gains or losses on open and closed hedging transactions are determined as the difference between the contract price and a reference price, generally closing prices on the NYMEX. 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. Changes in the value of the ineffective portion of all open hedges is recognized in earnings quarterly. Pre-tax losses relating to hedging in 2000 and 2001 were $43.2 million and $6.2 million, respectively. A hedging gain of $17.8 million was realized in 2002. Over the last three years, the Company has recorded a cumulative pre-tax hedging loss of $31.6 million. When combined with the $32.9 million unrealized pre-tax loss at year-end 2002, this results in a cumulative net loss of $64.5 million. 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 Balance sheet as OCI, a component of Stockholders' equity. Due to additional hedging activity and rising prices, the fair value on March 31, 2003 was a loss of $108.7 million.

Interest Rates

At December 31, 2002, the Company had $368.0 million of debt (including Trust preferred) outstanding. Of this amount, $175.7 million bears interest at fixed rates averaging 7.0%. Senior debt and non-recourse debt totaling $192.3 million bears interest at floating rates, which averaged 3.3% at year-end 2002, excluding interest rate swaps. At December 31, 2002, Great Lakes had $100.0 million subject to interest rate swap agreements, of which 50% is consolidated at Range. These swaps consist of five agreements totaling $35.0 million at an average rate of 4.6% which expire in June 2003, two agreements totaling $45.0 million at rates of 7.1% which expire in May 2004 and two agreements of $10.0 million each at an average rate of 2.3% which expire in December 2004. The 30-day LIBOR rate on December 31, 2002 was 1.4%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2002 would cost the Company approximately $1.4 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 fixed income securities. These initiatives have helped reduce Parent company bank debt to $115.8 million and total debt (including Trust preferred) to $368.0 million at December 31, 2002. While the Company believes its financial position has stabilized, management believes its leverage remains too high. The Company believes it should further reduce debt as a percentage of its capitalization. The Company currently believes it has sufficient liquidity and cash flow to meet its obligations for the next 12 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.

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. 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 2000 and 2001 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. The Company expects an increase in these costs for 2003. Increases in commodity prices can cause inflationary pressures specific to the industry to also increase.

RESULTS OF OPERATIONS

Volumes and Sales Prices

	2000	2001	2002
Selected operating data			
Average daily production			
Crude oil (per bbl)	5,560	5,250	5,131
NGLs (per bbl)	993	893	1,114
Natural gas (mcfs)	112,128	115,831	112,592
Total (mcfes)	151,442	152,684	150,061
Average sales prices (excluding hedging)			
Crude oil (per bbl)	$ 28.15	$ 23.34	$ 23.34
NGLs (per bbl)	$ 18.42	$ 17.33	$ 12.93
Natural gas (per mcf)	$ 3.71	$ 3.91	$ 3.02
Average sales prices (including hedging)			
Crude oil (per bbl)	$ 23.30	$ 25.55	$ 22.25
NGLs			

(per bbl) $ 18.42 $ 17.33 $ 12.93 Natural gas (per mcf) $ 2.90 $ 3.66 $ 3.50 Total (per mcfe) $ 3.12 $ 3.75 $ 3.49

The following table identifies certain items included in the results of operation. It is presented to assist in a comparison of the last three years. The table should be read in conjunction with the following discussion of results of operations.

	Year-Ended December 31,		
	2000	2001	2002
	(in thousands)		
Increase(decrease) in revenues			
Write-down of marketable securities	$ --	$ (1,715)	$ (1,220)
Loss on Enron contracts	--	(1,352)	--
Gain/(loss) on asset sales	(1,116)	689	161
Effect of SFAS 133 (commodities)	--	2,351	(2,730)
Hedging gains (losses)	(43,187)	(6,194)	17,790
Recovery from arbitration	--	--	715
	$(44,303)	$ (6,221)	$ 14,716
Increase(decrease) in expenses			
Provision for impairment	$ --	$ 31,085	$ --
General and administration non-cash expense (a)	3,405	(2,410)	1,023
Bad debt expense	615	688	150
Effect of SFAS 133 (interest)	--	1,403	275
Adjustment of IPF valuation allowance	(2,891)	122	4,240
	$ 1,129	$ 30,888	$ 5,688
Extraordinary Items			
Gain on retirement of debt, net of taxes	$ 17,763	$ 3,951	$ 2,014

(a) Provision for additional G&A representing the mark-to-market expense related to stock held in the deferred compensation plan.

Comparison of 2002 to 2001

Net income in 2002 totaled $25.8 million compared to $17.7 million in 2001. A $4.0 million gain on retirement of securities was realized in 2001 versus $2.0 million in 2002. The 2002 gain was net of deferred taxes of $1.1 million. Production decreased 2% to 150.1 Mmcfe per day due to lower production at Matagorda 519 and other production declines in the Gulf Coast. Revenues of $195.3 million were $24.1 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 mcfe. Production expenses decreased $3.0 million to $40.4 million as a result of lower production and property taxes, and reduced workover costs in the Gulf of Mexico. Operating cost per mcfe produced averaged $0.74 in 2002 versus $0.78 in 2001.

Transportation and processing revenues were about 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, net. During 2002, IPF expenses included $1.7 million of administrative costs, $937,000 of interest costs and $4.2 million was added to its valuation allowances.

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 expenses increased 41% due to an increase in non-cash mark-to-market compensation expense ($3.4 million), additional personnel costs ($1.4 million), higher insurance costs ($233,000), higher legal and consulting costs ($317,000) offset by lower bad debt expenses. The average number of general and administrative personnel increased 12% between 2001 and 2002.

Other income decreased from income of $490,000 in 2001 to a loss of $2.9 million in 2002. 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 hedges. 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. Average outstandings on the Parent credit facility were $90.5 million and $105.3 million for 2001 and 2002, respectively, and the average interest rates were 6.4% and 3.4%, respectively.

Depletion, depreciation and amortization ("DD&A") decreased 1% to $76.8 million as a result of lower production and the mix of production between depletion pools offset by higher depletion rates. 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 currently estimates that the DD&A rate for 2003 will remain at roughly $1.44 per mcfe.

The Company recorded a $31.1 million provision for impairment on acreage and proved properties at year-end 2001. No impairment was recorded in 2002.

Comparison of 2001 to 2000

Net income in 2001 totaled $17.7 million compared to $36.6 million in 2000. A $17.8 million gain on retirement of securities was realized in 2000 versus $4.0 million in 2001. The fourth quarter of 2001 included an impairment charge of $31.1 million. Production increased to 152.7 Mmcfe per day, a 1% increase from the prior year. Revenues benefited from a 20% increase in average prices to $3.75 per mcfe. The average price received for oil increased 10% to $25.59 per barrel and for gas increased 26% to $3.65 per mcfe. Production expenses increased $2.9 million to $43.4 million as a result of higher production and property taxes, increased workover costs and slightly higher costs for labor, services and supplies. Operating cost per mcfe produced averaged $0.78 in 2001 versus $0.73 in 2000.

Transportation and processing revenues decreased 35% to $3.4 million due to the impact of the sale of a gas processing plant in mid-2000 and lower NGL prices. IPF's $6.6 million of revenues declined 7% from 2000. IPF records income on payments for 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. During 2001, IPF expenses included $1.8 million of administrative costs and $1.8 million of interest. In 2001, a favorable adjustment to IPF reserves of $1.8 million, due to favorable prices early in the year, was more than offset by a year-end increase in the valuation allowance of $2.0 million. During 2000, IPF expenses included $1.5 million of administrative costs and $3.4 million of interest costs. In 2000, a favorable adjustment of $2.9 million was recorded to IPF valuation allowances.

Exploration expense increased 84% to $5.9 million primarily due to additional seismic activity and increased personnel expenses. General and administrative expenses decreased 18% due to a decline in non-cash mark-to-market compensation expense of $5.8 million offset by additional personnel costs ($1.4 million), higher legal and occupancy costs ($1.2 million) and additional costs ($600,000) incurred from having duplicate functions at Great Lakes and Range. The average number of general and administrative personnel increased 15% from 2000 to 2001.

Other income increased from a loss of $722,000 in 2000 to a gain of $490,000 in 2001. 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 hedges. The 2000 period included a $1.1 million loss on asset sales. Interest expense decreased 19% to $32.2 million primarily as a result of lower average outstanding balances and falling interest rates. Average outstandings on the Parent facility were $124.7 million and $90.5 million for 2000 and 2001, respectively, and the average interest rates were 8.8% and 6.4%, respectively.

DD&A increased 16% to $77.6 million as a result of the mix of production between depletion pools and higher depletion rates. The DD&A rate per mcfe in 2001 was $1.39, an $0.18 increase from 2000. The DD&A rate is determined based on year-end reserves (based on futures prices) 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 2001 was $1.60 per mcfe.

The Company recorded a provision for impairment on acreage of $5.1 million and proved properties for $25.9 million at year-end 2001. In evaluating possible impairment, the Company evaluates acreage on a separate basis from proved properties. Acreage is assessed periodically to determine whether there has been a decline in value. If a decline is indicated, an impairment is recognized. The Company compares the carrying value of its acreage to the assessment of value that could be recovered from sale, farm-out or exploitation. The Company considers other additional information it believes relevant in evaluating the properties' fair value, such as geological assessment of the area, other acreage purchases in the area and the timing of associated drilling. The following acreage was impaired in 2001 for the reasons indicated (in thousands).

Acreage Pool	Reason for Impairment	Amount
Matagorda Island 519	Probability of drilling reduced based on current assessment of risk and cost	$1,704
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
West Delta 30	Probability of drilling reduced based on current assessment of risk and cost	688

Total		$5,141
		======

The impairment evaluation on proven properties is based on proved reserves and estimated future cash flows, including revenues from anticipated oil and gas production, severance taxes, direct operating expenses and capital costs. The following properties were impaired in 2001 based on analysis of future cash flows (in thousands):

Property Pool	Reason for Impairment	Amount
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 oil price	99

Total		$25,944
		=======

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's 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.

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 oil and gas production from proved reserves. Pursuant to these swaps, Range receives a fixed price for its production and pays market prices to the counterparty. Hedging is intended to reduce the impact of oil and gas price fluctuations. 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. Range does not hold or issue derivative instruments for trading purposes.

As of December 31, 2002, Range had oil and gas hedges in place covering 64.6 Bcf of gas and 1.6 million barrels of oil. Their fair value, represented by the estimated amount that would be realized upon termination, based on contract versus NYMEX prices, approximated a net pre-tax loss of $32.9 million at that date. These contracts expire monthly through December 2005 and cover approximately 90%, 75% and 10% of anticipated production from proved reserves for 2003, 2004 and 2005, respectively. Gains or losses on open and closed hedging transactions are determined as the difference between the contract price and a reference price, generally closing prices on the NYMEX. 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. Any ineffective portion of such hedges is recognized in earnings as it occurs. Net pre-tax losses relating to these derivatives in 2000 and 2001 were $43.2 million and $6.2 million, respectively. A gain of $17.8 million was recorded in 2002. Effective January 1, 2001, the unrealized gains (losses) on these hedging positions were recorded at an estimate of the fair value based on a comparison of the contract price and a reference price, generally NYMEX, on the Company's Balance sheet as OCI, a component of Stockholders' equity.

The Company had hedge agreements with Enron for 22,700 Mmbtus per day, at $3.20 per Mmbtu for the first three contract months of 2002. Based on accounting requirements, the Company recorded an allowance for bad debts at year-end 2001 of $1.4 million, offset by a $318,000 ineffective gain included in 2001 income and $1.0 million gain included in OCI at year-end 2001 related to these amounts due from Enron. The gain included in OCI at year-end 2001 was included in income in the first quarter of 2002. The last of the Enron contracts expired in March 2002.

In 2002, a 10% reduction in oil and gas prices, excluding amounts fixed through hedging transactions, would have reduced revenue by $17.5 million. If oil and gas futures prices at December 31, 2002 had declined by 10%, the unrealized hedging loss at that date would have decreased 95% or $31.3 million.

Interest Rate Risk. At December 31, 2002, the Company had $368.0 million of debt (including Trust preferred) outstanding. Of this amount, $175.7 million bears interest at fixed rates averaging 7.0%. Senior debt and non-recourse debt totaling $192.3 million bears interest at floating rates, excluding interest rate swaps, which averaged 3.4% at that date. At December 31, 2002, Great Lakes had interest rate swap agreements totaling $100.0 million, 50% of which is consolidated by Range. Five agreements totaling $35.0 million at an average rate of 4.6% expire in June 2003. Two agreements totaling $45.0 million at rates of 7.1% expire in May 2004. Two agreements of $10.0 million each at 2.3% expire in December 2004. On December 31, 2002, the 30-day LIBOR rate was 1.4%. A 1% decrease in short-term interest rates on the floating-rate debt outstanding (net of amounts fixed through hedging transactions) at December 31, 2002 would cost the Company approximately $1.4 million in additional annual interest.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Reference is made to the Index to Financial Statements on page 43 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.

MANAGEMENT RESPONSIBILITY FOR FINANCIAL STATEMENTS

The financial statements have been prepared by management in conformity with generally accepted accounting principles. Management is responsible for the fairness and reliability of the financial statements and other financial data included in this report. In the preparation of the financial statements, it is necessary to make informed estimates and judgments based on currently available information on the effects of certain events and transactions. The Company maintains accounting and other controls which management believes provide reasonable assurance that financial records are reliable, assets are safeguarded and transactions are properly recorded. However, limitations exist in any system of internal control based upon the recognition that the cost of the system should not exceed benefits derived. The Company's independent auditors, KPMG LLP, are engaged to audit the financial statements and to express an opinion thereon. Their audit is conducted in accordance with generally accepted auditing standards to enable them to report whether the financial statements present fairly, in all material respects, the financial position and results of operations in accordance with generally accepted accounting principles.

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

As more fully disclosed in our Form 8K and Form 10-Q filed by the Company on July 15, 2002, the Company dismissed its auditor, Arthur Andersen LLP, and appointed KPMG LLP, during 2002. There were no disagreements with our prior accounting firm prior to its dismissal.

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 2002 annual stockholders' meeting. Officers are appointed by the Board.

	AGE	OFFICE HELD SINCE	POSITION
Thomas J. Edelman	52	1988	Chairman and Chairman of the Board
John H. Pinkerton	48	1990	President and Director
Robert E. Aikman	71	1990	Director
Anthony V. Dub	53	1995	Director
V. Richard Eales	66	2001	Director
Allen Finkelson	56	1994	Director
Jonathan S. Linker	54	2002	Director
Alexander P. Lynch	50	2000	Director
Terry W. Carter	50	2001	Executive Vice President - Exploration and Production
Eddie M. LeBlanc III	54	2000	Senior Vice President and Chief Financial Officer
Herbert A. Newhouse	58	1998	Senior

			Vice President - Gulf Coast
Chad L. Stephens	47	1990	Senior Vice President - Corporate Development
Rodney L. Waller	53	1999	Senior Vice President and Corporate Secretary

Thomas J. Edelman, Chairman and Chairman of the Board of Directors, joined the Company in 1988. From 1981 to 1997, he served as a Director and President of Snyder Oil Corporation ("SOCO"), a publicly traded independent oil company. In 1996, Mr. Edelman became Chairman and Chief Executive Officer of Patina Oil & Gas Corporation. Prior to 1981, Mr. Edelman was a Vice President of The First Boston Corporation. From 1975 through 1980, Mr. Edelman was with Lehman Brothers Kuhn Loeb Incorporated. Mr. Edelman received a Bachelor of Arts, magna cum laude, from Princeton University and his Masters in Finance from Harvard University's Graduate School of Business Administration. Mr. Edelman serves as a director of Star Gas Partners, L.P., a publicly traded master limited partnership which distributes fuel oil and propane.

John H. Pinkerton, President and a Director, became a Director in 1988. He joined the Company and was appointed President in 1990. Previously, Mr. Pinkerton was Senior Vice President-Acquisitions of 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. Mr. Aikman is Chairman of WhamTech, Inc. and Vision Resources L.L.C. 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. Mr. Dub joined CSFB in 1971 and was named a Managing Director in 1981. Mr. Dub led a number of departments during his 27 year career at CSFB including the Investment Banking Department. Mr. Dub is a director of Capital IQ, Inc. 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 a financial consultant serving energy and information technology businesses. 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 was elected to the Board at the 2002 Annual Meeting. Mr. Linker 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, the largest private equity firm investing exclusively in energy, in 1988 and was a Managing Director of the firm from 1996 until July 2001. 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.

Alexander P. Lynch became a Director in 2000. Mr. Lynch currently serves as Managing Director of J.P. Morgan, a subsidiary of J.P. MorganChase & Co., and is a Director of Patina Oil and Gas Corporation. Until its merger into J.P. MorganChase, Mr. Lynch was a General Partner of The Beacon Group. Previously, he was Co-President and Chief Executive Officer of The Bridgeford Group, a financial advisory firm acquired by Beacon in 1997. Prior to 1991, Mr. Lynch was a Managing Director of Lehman Brothers. Mr. Lynch received a Bachelor of Arts from the University of Pennsylvania and a Masters from the Wharton School of Business at the University of Pennsylvania.

Terry W. Carter, Executive Vice President-Exploration and Production, joined the Company in 2001. Previously, Mr. Carter provided consulting services to independent oil and gas companies. From 1976 to 1999, Mr. Carter was employed by Oryx Energy Company, holding a variety of positions including Planning Manager, Development Manager and Manager of Drilling. Mr. Carter received a Bachelor of Science degree in Petroleum Engineering from Tulsa University.

Eddie M. LeBlanc III, Senior Vice President and Chief Financial Officer, joined the Company in 2000. Previously, Mr. LeBlanc was a founder of Interstate Natural Gas Company, which merged into Coho Energy in 1994. At Coho, Mr. LeBlanc served as Senior Vice President and Chief Financial Officer. Mr. LeBlanc's 27 years of experience include assignments in the oil and gas subsidiaries of Celeron Corporation and Goodyear Tire and Rubber. Prior to entering the oil industry, Mr. LeBlanc was with a national accounting firm, he is a certified public accountant, a chartered financial analyst and received a Bachelor of Science from University of Southwestern Louisiana.

Herbert A. Newhouse, Senior Vice President - Gulf Coast, joined the Company in 1998. Previously, 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. Previously, Mr. Stephens was with Duer Wagner & Co., an independent oil and gas producer, since 1988. 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. Previously, Mr. Waller was a Senior Vice President of SOCO, now part of Devon Energy Corporation. Before joining SOCO, Mr. Waller was with Arthur Andersen. Mr. Waller received a Bachelor of Arts from Harding University.

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

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, 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.

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, Finkelson and Lynch.

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. One of the principal responsibilities of the Executive Committee is to be available to review and approve smaller acquisitions. The members of the Executive Committee are Messrs. Edelman, Finkelson and Pinkerton.

Nominating Committee. The Nominating Committee reviews background information on candidates for the Board of Directors and makes recommendations to the Board regarding such candidates. The members of the Nominating Committee are Messrs. Aikman, Finkelson and Lynch.

ITEM 11. COMPENSATION OF EXECUTIVE OFFICERS AND DIRECTORS

Information with respect to officers' compensation is incorporated herein by reference to the Company's 2003 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 2003 Proxy Statement.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None.

ITEM 14. CONTROLS AND PROCEDURES

Within the 90 days prior to the date of this report, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Exchange Act Rule 13a-14. Based upon that evaluation, the Chief Executive Officer and the 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 the Company's periodic filings with the Securities and Exchange Commission. No significant changes in the Company's internal controls or other factors that could affect these controls have occurred subsequent to the date of such evaluation.

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
- ----------
- ----------
- 3.1.1. Certificate of Incorporation of Lomak dated March 24, 1980 (incorporated by reference to the Company's Registration Statement (No. 33-31558)).
3.1.2. Certificate of Amendment of Certificate of Incorporation dated July 22, 1981 (incorporated by reference to the Company's Registration Statement (No. 33-31558)).
3.1.3. Certificate of Amendment of Certificate of Incorporation dated September 8, 1982 (incorporated by reference to the Company's Registration Statement (No. 33-31558)).
3.1.4.

Certificate of Amendment of Certificate of Incorporation dated December 28, 1988 (incorporated by reference to the Company's Registration Statement (No. 33-31558)).

3.1.5. Certificate of Amendment of Certificate of Incorporation dated August 31, 1989 (incorporated by reference to the Company's Registration Statement (No. 33-31558)).

3.1.6. Certificate of Amendment of Certificate of Incorporation dated May 30, 1991 (incorporated by reference to the Company's Registration Statement (No. 333-20259)).

3.1.7. Certificate of Amendment of Certificate of Incorporation dated November 20, 1992 (incorporated by reference to the Company's Registration Statement (No. 333-20257)).

3.1.8. Certificate of Amendment of Certificate of Incorporation dated May 24, 1996 (incorporated by reference to the

Company's Registration Statement (No. 333-20257)).
3.1.9. Certificate of Amendment of Certificate of Incorporation dated October 2, 1996 (incorporated by reference to the Company's Registration Statement (No. 333-20257)).
3.1.10. Restated Certificate of Incorporation as required by Item 102 of Regulation S-T (incorporated by reference to the Company's Registration Statement (No. 333-20257)).
3.1.11. Certificate of Amendment of Certificate of Incorporation dated August 25, 1998 (incorporated by reference to the Company's Registration Statement (No. 333-62439)).
3.1.12 Certificate of Amendment of Certificate of Incorporation dated May 25, 2000 (incorporated by reference to the Company's Form 10-Q dated August 8, 2000).
3.2 By-Laws of the Company (incorporated by reference to the Company's

Registration Statement (No. 33-31558)). 4.1 Specimen certificate of Lomak Petroleum, Inc. (incorporated by reference to the Company's Registration Statement (No. 333-20257)). 4.2 Certificate of Trust of Lomak Financing Trust (incorporated by reference to the Company's Registration Statement (No. 333-43823)). 4.3 Amended and Restated Declaration of Trust of Lomak Financing Trust dated as of October 22, 1997 by The Bank of New York (Delaware) and the Bank of New York as Trustees and Lomak Petroleum, Inc. as Sponsor (incorporated by reference to the Company's Registration Statement (No. 333-43823)).

Exhibit No. Description - - ---------- ---- ------- 4.4.1 Indenture dated as of October 22, 1997, between Lomak Petroleum, Inc. and The Bank of New York (incorporated by reference to the Company's Registration Statement (No. 333-43823)). 4.4.2 First Supplemental Indenture dated as of October 22, 1997, between Lomak Petroleum, Inc. and The Bank of New York (incorporated by reference to the Company's Registration Statement (No. 333-43823)). 4.5 Form of 5.75% Preferred Convertible Securities (included in Exhibit 4.5 above). 4.6 Form of 5.75% Convertible Junior Subordinated Debentures (included in Exhibit 4.7 above). 4.7 Convertible Preferred Securities Guarantee Agreement dated October 22, 1997, between Lomak Petroleum, Inc., as Guarantor, and The Bank of New York as Preferred Guarantee Trustee (incorporated by reference to the Company's Registration Statement (No. 333-43823)). 4.8 Common Securities Guarantee Agreement dated October 22, 1997, between Lomak Petroleum, Inc., as

Guarantor, and The Bank of New York as Common Guarantee Trustee. (incorporated by reference to the Company's Registration Statement No. 333-43823)). 4.9 Form of Trust Indenture relating to the Senior Subordinated Notes due 2007 between Lomak Petroleum, Inc., and Fleet National Bank as trustee (incorporated on the Company' s Registration Statement (No. 333-20257)). 4.10 Credit Agreement, dated as of June 7, 1996, between Domain Finance Corporation and Compass Bank -- Houston (including the First and the Second Amendment thereto) (incorporated by reference to Exhibit 10.3 of Domain Energy Corporation's Registration Statement on Form S-1 filed with the Commission on April 4, 1997 and Exhibit 10.3 of Amendment No. 1 to Domain Energy Corporation's Registration Statement on Form S-1 filed with the Commission on May 21, 1997) (File No. 333- 24641). 4.11 Corrected Certificate of Designations of Preferred Stock of Range Resources Corporation Designated As $2.03 Convertible Exchangeable Preferred Stock, Series D (incorporated by reference to the Company's Form 10-Q dated November 6, 2000). 10.1 Incentive and Non-Qualified Stock Option Plan dated March 13, 1989 (incorporated by reference to the Company's Registration Statement (No. 33-31558)). 10.2 Advisory Agreement dated September 29, 1988 between Lomak and SOCO (incorporated by reference to the Company's Registration Statement (No. 33-31558)). 10.3.1 1989 Stock Purchase Plan (incorporated by reference to the Company's Registration Statement (No. 33-31558)). 10.3.2 Amendment to the Lomak Petroleum, Inc., 1989 Stock Purchase Plan, as amended (incorporated by reference to the Company's Registration Statement (No. 333-44821)). 10.4 Form of Directors Indemnification Agreement (incorporated by reference to the Company's Registration Statement (No. 333-47544)). 10.5.1 1994 Outside Directors Stock Option Plan (incorporated by reference to the Company's Registration Statement (No. 33-47544)). 10.5.2 1994 Outside Directors Stock Option Plan - Amendment No. 1 (incorporated by reference to the Company's Registration Statement (No. 333-40380)). 10.5.3 1994

Outside Directors Stock Option Plan - Amendment No. 2 (incorporated by reference to the Company's Registration Statement (No. 333-40380)).

10.5.4 1994 Outside Directors Stock Option Plan - Amendment No. 3 (incorporated by reference to the Company's Registration Statement (No. 333-40380)).

10.5.5 1994 Outside Directors Stock Option Plan - Amendment No. 4 (incorporated by reference to the Company's Registration Statement (No. 333-40380)).

10.6 1994 Stock Option Plan (incorporated by reference to the Company's Registration Statement (No. 33-47544)).

10.7 Registration Rights Agreement dated October 22, 1997, by and among Lomak Petroleum, Inc., Lomak Financing Trust, Morgan Stanley & Co. Incorporated, Credit Suisse First Boston, Forum Capital Markets L.P. and McDonald Company Securities, Inc., (incorporated by reference to the Company's Registration Statement (No. 333-43823)).

10.8.1 1997 Stock Purchase Plan (incorporated by reference to the Company's Registration Statement (No. 333-44821)).

Exhibit No.	Description
10.8.2	1997 Stock Purchase Plan, as amended (incorporated by reference to the Company's Registration Statement (No. 333-44821)).
10.8.3	1997 Stock Purchase Plan - Amendment No. 1 (incorporated by reference to the Company's Registration Statement No. 333-40380)
10.8.4	1997 Stock Purchase Plan - Amendment No. 2 (incorporated by reference to the Company's Registration Statement No. 333-40380)
10.8.5	1997 Stock Purchase Plan - Amendment No. 3 (incorporated by reference to the Company's Registration Statement No. 333-40380)
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 the Company's Registration Statement (No. 333-62439)).
10.10	Domain Energy Corporation 1997 Stock Option Plan

for Non-employee Directors (incorporated by reference to the Company's Registration Statement (No. 333-62439)).

10.11 $100,000,000 Credit Agreement between Range Energy Finance Corporation, as Borrower, and Credit Lyonnais New York Branch, as Administrative Agent and Certain Lenders dated December 14, 1999 (incorporated by reference to the Company's 1999 10K dated March 20, 2000.)

10.11.1 $100,000,000 Second Amendment to Credit Agreement between Range Energy Finance Corporation, as Borrower, and Credit Lyonnais New York Branch, as Administrative Agent and Certain Lenders dated December 14, 1999 (incorporated by reference to the Company's 1999 10K dated March 20, 2000.)

10.12 Purchase and Sale Agreement - Dated April 20, 2000 between Range Pipeline Systems, L.P. as Seller and Conoco Inc., as Buyer (incorporated by reference to the Company's 10-

Q dated August 8, 2000). 10.13 Gas Purchase Contract - Dated July 1, 2000 between Range Production I, L.P. as Seller and Conoco Inc., as Buyer (incorporated by reference to the Company's 10-Q dated August 8, 2000). 10.14 Application Service Provider and Outsourcing Agreement - Dated June 1, 2000 between Range Resources and Applied Terravision Systems Inc. (incorporated by reference to the Company's 10-Q dated August 8, 2000). 10.15.1 $225,000,000 Amended and Restated Credit Agreement among Range Resources Corporation, as Borrower, The Lenders from Time to Time Parties Hereto, as Lenders, Bank One, Texas, N.A., as Administrative Agent, Chase Bank of Texas, N.A., as Syndication Agent, and Bank of America, N.A., as Documentation Agent dated September 30, 1999 (incorporated by reference to the Company's 10Q dated November 10, 1999). 10.15.2 $225,000,000 First Amendment to

Credit Agreement among Range Resources Corporation, as Borrower, certain parties, as Lenders, Bank One, Texas, N.A., as Administrative Agent, Chase Bank of Texas, N.A., as Syndication Agent, and Bank of America, N.A., as Documentation Agent dated September 30, 1999 (incorporated by reference to the Company's 10K dated March 7, 2001).

10.15.3 $225,000,000 Second Amendment to Credit Agreement among Range Resources Corporation, as Borrower, certain parties, as Lenders, Bank One, Texas, N.A., as Administrative Agent, Chase Bank of Texas, N.A., as Syndication Agent, and Bank of America, N.A., as Documentation Agent dated September 30, 1999 (incorporated by reference to the Company's 10-Q dated August 8, 2000).

10.15.4 $225,000,000 Third Amendment to Credit Agreement among Range Resources Corporation, as Borrower, certain parties as Lenders, Bank One, Texas, N.A., as Administrative Agent, Chase Bank of Texas, N.A., as Syndication. Agent, and Bank of America, N.A., as Documentation Agent dated September 30, 1999 (incorporated by reference to the Company's 10-Q dated August 8, 2000).

10.15.5 $225,000,000 amended and restated Credit Agreement among Rang Resources Corporation, as Borrower, and Bank One, N.A., and the institutions named herein as lenders, Bank One, NA, as administrative agent and Banc One Capital Markets, Inc., as joint lead arranger and joint bookrunner and JP Morgan Chase Bank, as joint lead arranger and joint bookrunner effective May 2, 2002 (incorporated by reference to the Company's 10Q dated May 6, 2002).

Exhibit No. Description - ----------- - ----------
10.15.6* $225,000,000 First Amendment to Credit agreement among Range Resources Corporation, as Borrowers, certain parties, as Lenders, Bank One, Texas, N.A., as Administrative Agent, Chase Bank of Texas, N.A. as Syndication Agent and Bank of America, N.A. as Documentation Agent dated December 27, 2002. 10.17 Amended and Restated Range Resources Corporation 401(k) Plan and Trust, effective January 1, 1997 including adoption agreement (incorporated by reference to the Company's 10Q dated May 6, 2002). 10.20 The Amended and Restated Deferred Compensation Plan for Directors and Selected Employees effective September 1, 2000 (incorporated by reference to the Company's 10K dated March 7, 2001). 21.1* Subsidiaries of Registrant. 23.1* Consent of Independent Public Accountants.

23.2* Consent of Independent Public Accountants.
23.3* Consent of H.J. Gruy and Associates, Inc., independent consulting petroleum engineers.
23.4* Consent of DeGoyler and MacNaughton, independent consulting petroleum engineers.
23.5* Consent of Wright and Company, independent consulting engineers.

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* Filed herewith.

(B) Reports on Form 8-K.

Form 8K dated November 13, 2002 (filed on November 13, 2002) reporting under Item 9 - Regulation FD Disclosure.

Form 8K dated November 14, 2002 (filed on November 20, 2002) reporting under Item 4 - Changes in Registrants Certifying Accountants.

Form 8K/A dated December 2, 2002 (filed on December 2, 2002) reporting under Item 4 - Changes in Registrants Certifying Accountants.

Form 8K/A dated November 14, 2002 (filed on December 9, 2002) reporting under Item 4 - Changes in Registrants Certifying Accountants.

(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.

SIGNATURES

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

Dated: March 5, 2003

RANGE RESOURCES CORPORATION

By: /s/ John H. Pinkerton

John H. Pinkerton
President

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/ Thomas J. Edelman Chairman and Chairman of the Board	Thomas J. Edelman	March 5, 2003
/s/ John H. Pinkerton President and Director	John H. Pinkerton	March 5, 2003
/s/ Eddie M. LeBlanc III Chief Financial and Accounting Officer	Eddie M. LeBlanc III	March 5, 2003
/s/ Robert E. Aikman Director	Robert E. Aikman	March 5, 2003
/s/ Anthony V. Dub Director	Anthony V. Dub	March 5, 2003
/s/ V. Richard Eales Director	V. Richard Eales	March 5, 2003
/s/ Allen Finkelson Director	Allen Finkelson	March 5, 2003
/s/ Jonathan S. Linker Director	Jonathan S. Linker	March 5, 2003
/s/ Alexander P. Lynch Director	Alexander P. Lynch	March 5, 2003

I, John H. Pinkerton, certify that:

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

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

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

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation of the Evaluation Date;

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

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 5, 2003

/s/ John H. Pinkerton

John H. Pinkerton, President

I, Eddie M. LeBlanc, certify that:

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

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

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

    b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

    c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation of the Evaluation Date;

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

    a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 5, 2003

/s/ Eddie M. LeBlanc

Eddie M. LeBlanc, Chief Financial Officer

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, which reflects the relative energy content.

Parent 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.

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

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

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

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

proved developed 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.

RANGE RESOURCES CORPORATION

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULES

(ITEM 15[a], [d])

INDEPENDENT AUDITORS' REPORT

TO THE BOARD OF DIRECTORS AND STOCKHOLDERS
RANGE RESOURCES CORPORATION:

We have audited the accompanying consolidated balance sheets of Range Resources Corporation as of December 31, 2001 and 2002, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the years in the three-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 provides 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, 2001 and 2002, and the results of their operations and their cash flows for each of the years in the three-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

REPORT OF INDEPENDENT AUDITORS

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

We have audited the consolidated balance sheets 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. The financial statements of Great Lakes Energy Partners, L.L.C. as of December 31, 2001 and for the years ended December 31, 2000 and 2001, were audited by other auditors whose report dated September 17, 2002, expressed an unqualified opinion on those statements, included explanatory paragraphs that disclosed the change in the Company's method of accounting for derivative financial instruments and that the Company had restated its consolidated financial statements from inception (September 30, 1999) to December 31, 1999 and the years ended December 31, 2000 and 2001, which consolidated financial statements were previously audited by other independent auditors, who have ceased operations.

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 year then ended in conformity with accounting principles generally accepted in the United States.

/s/ ERNST & YOUNG LLP

Pittsburgh, Pennsylvania
January 31, 2003

RANGE RESOURCES CORPORATION

CONSOLIDATED BALANCE SHEETS
(IN THOUSANDS)

	DECEMBER 31, 2001	DECEMBER 31, 2002
ASSETS		
Current assets		
Cash and equivalents	$ 3,380	$ 1,334
Accounts receivable	25,295	26,832
IPF receivables, net (Note 2)	7,000	6,100
Unrealized derivative gain (Note 7)	37,165	4
Inventory and other	4,895	3,084
	77,735	37,354
IPF receivables, net (Note 2)	34,402	18,351
Unrealized derivative gain (Note 7)	14,936	13
Oil and gas properties, successful efforts method (Note 16)	1,047,629	1,154,549
Accumulated depletion	(514,272)	(590,143)
	533,357	564,406
Transportation and field assets (Note 2)	31,288	34,143
Accumulated depreciation	(13,108)	(16,071)
	18,180	18,072
Deferred tax asset, net (Note 13)	--	15,785
Other (Note 2)	3,852	

4,503 -------
---- --------
--- $ 682,462
$ 658,484
===========
===========
LIABILITIES
AND
STOCKHOLDERS'
EQUITY
Current
liabilities
Accounts
payable $
27,202 $
27,044
Accrued
liabilities
10,257 9,678
Accrued
interest
5,244 4,449
Unrealized
derivative
loss (Note 7)
397 26,035 --
--------- ---

43,100 67,206
----------- -

Senior debt
(Note 6)
95,000
115,800 Non-
recourse debt
(Note 6)
98,801 76,500
Subordinated
notes (Note
6) 108,690
90,901 Trust
preferred -
manditorily
redeemable
securities of
subsidiary
(Note 6)
89,740 84,840
Deferred tax
credits, net
(Note 13)
4,496 --
Unrealized
derivative
loss (Note 7)
2,235 9,079
Deferred
compensation
liability
(Note 11)
4,779 8,049
Commitments
and
contingencies
(Note 8)
Stockholders'
equity (Notes
5, 9 and 10)
Preferred
stock, $1
par,
10,000,000
shares
authorized,
none issued
or
outstanding -
- -- Common
stock, $.01
par,

100,000,000 shares authorized, 52,643,275 and 54,991,611 issued and outstanding, respectively 526 550 Capital in excess of par value 378,426 391,082 Stock held by employee benefit trust, 1,038,242 and 1,324,537 shares, respectively, at cost (Note 11) (4,890) (6,188) Retained earnings (deficit) (183,825) (158,059) Deferred compensation expense (139) (125) Other comprehensive income (loss) (Note 2) 45,523 (21,151) ----------- ----------- 235,621 206,109 ----------- ----------- $ 682,462 $ 658,484 =========== ===========

SEE ACCOMPANYING NOTES.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS
(IN THOUSANDS, EXCEPT PER SHARE DATA)

	YEAR-ENDED DECEMBER 31,		
	2000	2001	2002
Revenues			
Oil and gas sales	$ 173,082	$ 208,854	$ 190,954
Transportation and processing	5,306	3,435	3,495
IPF income (Note 2)	7,162	6,646	3,789
Other	(722)	490	(2,900)
	184,828	219,425	195,338
Expenses			
Direct operating	40,552	43,430	40,443
IPF	1,974	3,761	6,847
Exploration	3,187	5,879	11,525
General and administrative (Note 11)	14,953	12,212	17,240
Interest expense and dividends on trust preferred	39,953	32,179	23,153
Depletion, depreciation and amortization	66,968	77,573	76,820
Provision for impairment (Note 2)	--	31,085	--
	167,587	206,119	176,028
Pretax income	17,241	13,306	

19,310 Income tax (benefit) (Note 13) Current (1,574) (406) (4) Deferred -- -- (4,438) --------- --------- --------- (1,574) (406) (4,442) Income before extraordinary item 18,815 13,712 23,752 Gain on retirement of debt securities, net of taxes (Note 18) 17,763 3,951 2,014 --------- --------- --------- Net income 36,578 17,663 25,766 Gain on retirement of preferred stock 5,966 556 -- Preferred dividends (1,554) (10) -- --------- --------- --------- Net income available to common shareholders $ 40,990 $ 18,209 $ 25,766 ========= ========= ========= Comprehensive income (loss) (Note 2) $ 35,750 $ 63,825 $ (40,908) ========= ========= ========= Earnings per share (Note 14) Before extraordinary item - basic $ 0.55 $ 0.28 $ 0.45 ========= ========= ========= - diluted $ 0.54 $ 0.28 $ 0.44 ========= ========= ========= After extraordinary item - basic $ 0.97 $ 0.36 $ 0.49 ========= ========= ========= -

diluted $
0.96 $ 0.36 $
0.47
=========
=========
=========

SEE ACCOMPANYING NOTES.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
(IN THOUSANDS)

	YEAR-ENDED DECEMBER 31,		
	2000	2001	2002
CASH FLOW FROM OPERATIONS			
Net income	$ 36,578	$ 17,663	$ 25,766
Adjustments to reconcile net income to net cash provided by operations:			
Depletion, depreciation and amortization	66,968	77,573	76,820
Deferred income taxes	--	--	(3,353)
Write-down of marketable securities	--	1,715	1,220
Unrealized hedging (gains) losses	--	(1,019)	3,005
Provision for impairment	--	31,085	--
Allowance for bad debts	615	2,040	150
Allowance for IPF receivables	(2,891)	122	4,240
Amortization of deferred issuance costs	2,020	1,961	899
Deferred compensation adjustments	4,549	(68)	3,306
Gain on			

retirement
of
securities
(17,978)
(4,004)
(3,125)
(Gain) loss
on sale of
assets
1,116 (689)
(161)
Changes in
working
capital
Accounts
receivable
(6,568)
5,540
(2,685)
Inventory
and other
(522) 226
(893)
Accounts
payable
(5,627) 548
3,364
Accrued
liabilities
and other
(3,381)
(3,095) 639
-------- --
------- ---
------ Net
cash
provided by
operations
74,879
129,598
109,192 ---
----- -----
---- ------
--- CASH
FLOW FROM
INVESTING
Oil and gas
properties
(47,474)
(87,034)
(109,066)
Field
service
assets
(2,263)
(2,331)
(2,815) IPF
investments
(6,985)
(11,629)
(5,106) IPF
repayments
24,764
19,034
17,321
Asset sales
25,944
3,771 996 -
------- ---
------ ----
----- Net
cash used
in
investing
(6,014)
(78,189)
(98,670) --
------ ----
----- -----
---- CASH
FLOW FROM

FINANCING			
Net decrease in parent facility and non-recourse debt	(79,611)	(9,108)	(1,501)
Other debt repayment	--	(42,938)	(11,087)
Preferred dividends	(1,444)	(10)	--
Debt issuances fees	--	--	(984)
Issuance of common stock	1,798	1,488	1,004
Repurchase of preferred stock	--	(73)	--
Net cash used in financing	(79,257)	(50,641)	(12,568)
Change in cash	(10,392)	768	(2,046)
Cash and equivalents, beginning of year	13,004	2,612	3,380
Cash and equivalents, end of year	$ 2,612	$ 3,380	$ 1,334

SEE ACCOMPANYING NOTES.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(IN THOUSANDS)

PREFERRED
STOCK COMMON
STOCK ------
--------- --

DEFERRED
CAPITAL IN
STOCK HELD
RETAINED
OTHER PAR
PAR
COMPENSATION
EXCESS OF BY
EMPLOYEE
EARNINGS
COMPREHENSIVE
SHARES VALUE
SHARES VALUE
EXPENSE PAR
VALUE
BENEFIT
TRUST
(DEFICIT)
INCOME TOTAL
------ -----
------ -----

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BALANCE
DECEMBER 31,
1999 1,150 $
1,150 37,902
$ 379 $ (69)
$341,177
$(3,086)
$(236,502) $
189 $
103,238
Preferred
dividends --
-- -- -- --
-- --
(1,554) --
(1,554)
Issuance of
common -- --
974 10 (11)
3,115 (410)
-- -- 2,704
Conversion
of
securities
(930) (930)
10,312 103 -
- 20,633 --
-- -- 19,806
Other
comprehensive
income -- --
-- -- -- --
-- -- (828)
(828) Net
income -- --
-- -- -- --
-- 36,578 --
36,578 -----
- ------- --
---- ---- --

--- --------
------- ----
----- ------
-- ---------
BALANCE
DECEMBER 31,
2000 220 220
49,188 492
(80) 364,925
(3,496)
(201,478)
(639)
159,944 ----
-- ------- -
----- ---- -
---- -------
- ------- --
------- ----
---- -------
-- Preferred
dividends --
-- -- -- --
-- -- (10) -
- (10)
Issuance of
common -- --
858 8 (59)
4,030
(1,394) -- -
- 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
(139)
378,426
(4,890)
(183,825)
45,523
235,621
Issuance of
common -- --
717 7 14
4,313
(1,298) -- -
- 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
$(125)
$391,082
$(6,188)
$(158,059)
$(21,151) $
206,109
======
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SEE ACCOMPANYING NOTES.

RANGE RESOURCES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) ORGANIZATION AND NATURE OF BUSINESS

The Company is engaged in the development, acquisition and exploration of oil and gas properties primarily in the Southwestern, Gulf Coast and Appalachian regions of the United States. The Company also provides financing to smaller oil and gas producers through a wholly-owned subsidiary, Independent Producer Finance ("IPF"). The Company seeks to increase its reserves and production primarily through development and exploratory drilling and acquisitions. In 1999, Range and FirstEnergy Corp. ("FirstEnergy") contributed their Appalachian oil and gas properties to an equally owned joint venture, Great Lakes Energy Partners L.L.C. ("Great Lakes").

(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 are recognized as income; remaining receipts reduce receivables. Although receivables are concentrated in the oil industry, the Company does not view this as unusual credit risk. However, IPF's receivables are from small independent operators who usually have limited access to capital and the assets which underlie the receivables lack diversification. Therefore, operational risk is substantial and there is significant risk that required maintenance and repairs, development and planned exploitation may be delayed or not accomplished. A decrease in oil prices could cause an increase in IPF's valuation allowances and a corresponding decrease in income. At December 31, 2001 and 2002, IPF had valuation allowances of $13.0 million and $12.6 million, respectively. The Company had other allowances for doubtful accounts relating to its exploration and production business of $2.9 million and $835,000 at December 31, 2001 and 2002, respectively.

MARKETABLE SECURITIES

The Company has adopted Statement of Financial Accounting Standards No. 115, "Accounting for Certain Investments," ("SFAS 115") pursuant to which the holdings of equity securities qualify as available-for-sale and are recorded at fair value. Unrealized gains and losses are reflected in Stockholders' equity as a component of Other comprehensive income (loss). A decline in the market value of a security below cost deemed other than temporary is charged to earnings. Realized gains and losses are reflected in income. The Company owns approximately 18% of a very small publicly traded independent exploration and production company. This entity has experienced growing difficulties, operationally and financially. During 2001 and 2002, the Company determined that the decline in the market value of an equity security it holds was other than temporary and losses of $1.7 million and $1.2 million, respectively, were recorded as reductions to Other revenues. Based on its analysis of the investment and its assessment of the prospects of realizing any value on the stock, the Company determined that the investment had no determinable value at June 30, 2002 and the book value of the investment was fully reserved. In October 2002, several creditors sought to place this entity in involuntary bankruptcy.

INDEPENDENT PRODUCER FINANCE

IPF acquires dollar denominated 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 believed to relate to the return is recognized as income; remaining receipts reduce receivables. No interest income is recorded on impaired receivables and any payments received applicable to impaired receivables are applied as a reduction of the receivable. 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. As of December 31, 2002, receivables for which no valuation allowance existed totaled $12.2 million and the weighted average rate of return on that balance was 17%. Due to favorable oil and gas prices during the last nine months of 2000 and the first six months of 2001, certain of these receivables began to generate all or a greater than anticipated cash flow that favorably impacted the valuation of the receivables. As a result, $1.8 million of increases in receivables were recorded as a reduction in IPF expenses in 2001. However, because of lower prices and lower anticipated cash flows, IPF increased its reserve allowance by $2.0 million in the fourth quarter of 2001. During 2001 and 2002, IPF expenses were comprised of $1.8 million and $1.7 million of general and administrative costs and $1.8 million and $937,000 of interest, respectively. In 2000, IPF recorded a $2.9 million favorable adjustment to their valuation allowance. In 2001 and 2002, IPF recorded a $2.0 million and $4.2 million unfavorable adjustment to their valuation allowance, respectively. Based on the decline on the performance of the assets underlying the IPF receivables, $4.2 million was added to the valuation allowances in 2002. The valuation allowance at December 31, 2001 and 2002 was $13.0 million and $12.6 million, respectively.

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

	2000	2001	2002
Balance as of beginning of year	$(14,513)	$(10,927)	$(12,928)
Provisions charged to IPF expenses	(6,113)	(4,361)	(5,317)
Recoveries credited to IPF expenses	9,004	2,360	1,077
Amounts written off to principal	695	--	4,528
Balance as of end of year	$(10,927)	$(12,928)	$(12,640)

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. 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 is converted to gas equivalent basis ("mcfe") at the rate of six mcf per barrel. The depletion, depreciation and amortization ("DD&A") rates were $1.21, $1.39 and $1.40 per mcfe in 2000, 2001 and 2002, respectively. Unproved properties had a net book value of $49.5 million, $25.7 million and $19.0 million at December 31, 2000, 2001 and 2002, respectively. Unproved properties are reviewed each period for impairment and reduced to fair value if required.

The Company adopted Statements 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 No. 144. Long-lived assets are reviewed for potential impairments at the lowest level 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. In years where market information is not available, prices are escalated for inflation. 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 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/ 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

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

TRANSPORTATION, PROCESSING AND FIELD ASSETS

The Company's gas 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 sold its only remaining gas processing facility in June 2000. The Company receives third-party income for providing certain 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 balance sheet. These costs are generally amortized over the expected life of the related securities (using the sum-of-the year's digits amortization method which does not differ materially from the effective interest method). When a security is retired prior to maturity, related unamortized costs are expensed. At December 31, 2002, such deferred financing costs totaled $3.0 million. Other assets at December 31, 2002 includes $3.0 million unamortized debt issuance costs, $1.0 million of marketable securities held in the deferred compensation plan and $403,000 of long-term deposits.

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, 2001 and December 31, 2002 were not significant. However, the Company has recorded a net liability of $218,000 at December 31, 2002 for those wells where there are insufficient reserves to retire the imbalance.

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, established accounting and disclosure requirements using a fair value-based method of accounting for stock-based employee compensation plans. As allowed by SFAS No. 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 No. 123, as amended by SFAS No. 148, Accounting for Stock-Based Compensation -- Transition and Disclosure, which are included in Note 10 to the Consolidated financial statements.

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 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 is recognized in earnings quarterly. On adopting SFAS 133 in January 2001, the Company recorded a $72.1 million net unrealized pre-tax hedging loss on its balance sheet and an offsetting deficit in OCI. At December 31, 2002, this loss had become $32.9 million by year-end. 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. The reduction in OCI at December 31, 2002 related to increases in oil and gas prices since December 31, 2001. Of the $32.9 million unrealized pre-tax loss at December 31, 2002, $24.4 million of losses would be reclassified to earnings over the next 12 month period and $8.5 million for the periods thereafter, if prices remained constant. Actual amounts that will be reclassified will vary as a result of changes in prices.

The Company had hedge agreements with Enron North America Corp. ("Enron") for 22,700 Mmbtu per day, at $3.20 per Mmbtu covering the first three contract months of 2002. Based on accounting requirements, the Company recorded an allowance for bad debts at year-end 2001 of $1.4 million, offset by a $318,000 ineffective gain included in 2001 income and $1.0 million gain included in OCI at year-end 2001 due to Enron's collapse. The gain included in OCI at year-end 2001 was included in income in the first quarter of 2002. The last Enron contracts expired in March 2002.

The Company enters into hedging agreements to reduce the impact of volatile oil and gas prices. These contracts generally qualify as cash flow hedges, however, certain of the contracts have an ineffective portion (changes in realized prices that do not match the changes in hedge price) which is recognized in earnings. Prior to 2001, gains and losses were determined monthly and included in oil and gas revenues in the period the hedged production was sold. Starting in 2001, gains or losses on open contracts are recorded in OCI. 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.

COMPREHENSIVE INCOME

The Company follows Statement of Financial Accounting Standards No. 130, "Reporting Comprehensive Income," defined as changes in Stockholders' equity from non-owner sources. The following is a calculation of comprehensive income (loss) for each of the three years ended December 31, 2002 (in thousands):

	Year-Ended December 31,		
	2000	2001	2002
Net income	$ 36,578	$ 17,663	$ 25,766
Cumulative effect of change in accounting principle (a)	--		

(72,100) --
Net amount
reclassed to
earnings --
(6,194)
17,790
Change in
unrealized
hedging gain
(losses),
net --
122,853
(83,792)
Unrealized
gain (loss)
from
available-
for-sale
securities
(828) 931 --
Defaulted
hedge
contracts,
net (b) --
672 (672) --
------- ----
----- ------

Comprehensive
income
(loss) $
35,750 $
63,825 $
(40,908)
=========
=========
=========

(a) On adopting SFAS 133 on January 1, 2001, the Company recorded a $72.1 million liability for an unrealized pre-tax hedging loss on its balance sheet and an offsetting deficit in Other comprehensive income (loss).

(b) Includes $1.0 million gain related to amounts due from Enron.

USE OF ESTIMATES

The preparation of financial statements in conformity with accounting principles generally accepted 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. Estimates which may significantly impact the Company's financial statements include reserves, impairment tests on oil and gas properties, IPF valuation allowance and fair value of derivatives.

RECENT ACCOUNTING PRONOUNCEMENTS

On September 11, 2002, the Emerging Issues Task Force 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." Statement No. 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 debtor 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. Statement 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 Statement 84 applies to all conversions that both (a) occur pursuant to changed conversion privileges that are exercisable only for a 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 6% Debentures and Trust Preferred securities, each of which are convertible into common stock under the terms of the issue, 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 substantial discount to face value. Under the provisions of SFAS No. 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. Therefore, instead of recording gains on retirements of such securities acquired at substantial discounts to face value, an expense will be recorded. There will be no difference in total Stockholders' equity from the change in methods of recording the transactions. The Company intends to continue to consider exchanging debt securities for common stock of the Company, despite the negative impact on its financial statements. If, in the opinion of management, the transaction is favorable for the Company and its shareholders, the transaction will be executed despite the negative impact on the financial statements.

In April 2002, the 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"). Extinguishment of debt will be accounted for in accordance with Accounting Principles Board Opinion No. 30 "Reporting the Results of Operations, Reporting the Effects of Disposal of a Segment of a Business and Extraordinary, Unusual and Infrequently Occurring Events and Transactions." SFAS 145 has a dual effective date. The provisions relating to accounting for leases were applicable to transactions occurring after May 15, 2002. The provisions relating to the early extinguishment of debt will be adopted by the Company on January 1, 2003. As a result, gains from early extinguishment of debt, which are currently reported as extraordinary items, will be reported in income from continuing operations in comparative financial statements subsequent to the adoption of SFAS 145.

In June 2001, FASB issued Statement of Financial Accounting Standards No. 143 "Asset Retirement Obligations" ("SFAS 143") establishing a new accounting model for the recognition of retirement obligations associated with tangible long-lived assets and requiring that retirement cost should be capitalized as part of an asset's cost and subsequently systematically expensed. The Company will adopt SFAS 143 on January 1, 2003 as required. The adoption of this statement will result in a cumulative effect and be reported as a change in accounting principle relating to the abandonment of oil and gas producing facilities. The Company cannot reasonably quantify the effect of the adoption on either its financial position or results of operations at this time.

In June 2002, the FASB issued Statement of Financial Accounting Standards No. 146 "Accounting for Exit or Disposal Activities ("SFAS 146"). SFAS 146 will be effective for exit or disposal activities that are initiated after December 31, 2002.

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. Purchase prices were 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 $4.7 million, $9.5 million and $21.8 million, during the years ended December 31, 2000, 2001 and 2002, respectively. These purchases include $1.7 million, $4.2 million and $15.6 million for proved oil and gas reserves, respectively, the remainder represents unproved acreage purchases.

(4) DISPOSITIONS

In June 2000, the Company sold a gas plant for $19.7 million and recorded a $716,000 loss.

The following table presents unaudited pro forma operating results as if the sale of the gas plant had occurred on January 1, 2000 (in thousands, except per share data).

	Pro Forma Year-Ended December 31, 2000
Revenues	$182,683
Net income	36,879
Earnings per share - basic and diluted	0.98
Total assets	669,179
Stockholders' equity	157,063

The pro forma results have been prepared for comparative purposes only. They do not purport to present actual results that would have been achieved or to be indicative of future results.

(5) SUPPLEMENTAL CASH FLOW INFORMATION

Twelve months ended December 31, (in thousands)	2000	2001	2002
NON-CASH INVESTING AND FINANCING ACTIVITIES:			
Common stock issued Under benefit plans	$ 983	$	

2,174 $
3,092
Exchange
for fixed
income
securities
37,086
14,222
8,359 In
payment of
preferred
dividends
110 -- --
CASH USED
IN
(PROVIDED
BY)
OPERATING
ACTIVITIES:
Income
taxes paid
(refunded)
(355) 14
(96)
Interest
paid
42,192
31,207
23,277

The Company has and will continue to consider exchanging common stock or equity-linked securities for debt, despite the negative impact on its financial statements due to SFAS 84 (see Note 2 "Recent Accounting Pronouncements"). If, in the opinion of management, the transaction is favorable for the Company and its shareholders, the transaction will be executed. Existing stockholders may be materially diluted if substantial exchanges are consummated. The extent of dilution will depend on the number of shares and price at which common stock is issued, the price at which newly issued securities are convertible and the price at which debt is acquired.

(6) INDEBTEDNESS

The Company had the following debt and Trust preferred (as herein defined) outstanding as of the dates shown (in thousands). Interest rates, excluding the impact of interest rate swaps, at December 31, 2002 are shown parenthetically:

	December 31,	
	2002	2001
Senior debt		
Parent credit facility (3.4%)	$ 95,000	$115,800
Non-recourse debt		
Great Lakes credit facility (3.2%)	75,001	76,500
IPF credit facility	23,800	--
	98,801	76,500
Subordinated debt		
8.75% Senior Subordinated Notes due 2007	79,115	69,281
6% Convertible Subordinated Debentures due 2007	29,575	21,620
	108,690	90,901
Total debt	302,491	283,201
Trust preferred - manditorily redeemable securities of subsidiary	89,740	84,840
Total	$392,231	$368,041

From January 1, 2003 to March 1, 2003, the Company exchanged an additional $880,000 face amount of the 6% Debentures for 129,000 shares of common stock and repurchased for cash $400,000 face value of $5.75% Trust preferred. The recording of 6% Debenture exchange includes an inducement expense of $465,000. Interest paid in cash during the years ended December 31, 2001 and 2002 totaled $31.2 million and $23.3 million, respectively. No interest expense was capitalized during 2000, 2001 and 2002.

PARENT SENIOR DEBT

In May 2002, the Company entered into an amended $225 million secured revolving bank facility (the "Parent Facility"). The Parent Facility provides for a borrowing base subject to redeterminations in April and October. On December 31, 2002, the borrowing base on the Parent Facility was $147.0 million, of which $31.1 million was available. On March 1, 2003, the borrowing base on the Parent Facility was $147.0 million of which $23.5 million was available. Redeterminations are based on a variety of factors, including banks' projection of future cash flows. Redeterminations require approval by 75% of the lenders; redeterminations which result in an increase require 100% approval. The Company has the right to increase the borrowing base by up to $10.0 million during any six-month borrowing base period based on a percentage of the fair value of subordinated debt (8.75% Senior subordinated notes, 6% Convertible subordinated debentures or Trust preferred) retired by the Company. Interest is payable the earlier of quarterly or as LIBOR notes mature. The loan matures in July 2005. A commitment fee is paid quarterly on the undrawn balance at an annual rate of 0.25% to 0.50%. The interest rate on the Parent Facility is LIBOR plus 1.50% to 2.25%, depending on outstandings. At December 31, 2002, the commitment fee was 0.375% and the interest rate margin was 0.75%. The weighted average interest rates on the Parent Facility was 6.4% and 3.9% for the years ended December 31, 2001 and 2002, respectively. As of March 1, 2003, the interest rate was 3.4%.

NON-RECOURSE DEBT

The Company consolidates its proportionate share of borrowings on Great Lakes' $275.0 million secured revolving bank facility (the "Great Lakes Facility"). The Great Lakes Facility is non-recourse to Range and provides for a borrowing base, which is subject to semi-annual redeterminations in April and October. Cash distributions to members of the joint venture are limited by a covenant contained in the Great Lakes Facility. As of December 31, 2002, $25.1 million was available for distribution to members. There is an agreement between the parties of the joint venture that Great Lakes will distribute, on a quarterly basis, amounts deemed to be a tax distribution. This amount, net to the Company, was $3.2 million in 2002 and is estimated to be $4.5 million in 2003. As of December 31, 2002, $25.1 million was available for distribution to members. As of December 31, 2002, the borrowing base was $205.0 million of which $52.0 million was available. On March 1, 2003, the borrowing base was $205.0 million of which $44.0 million was available. Interest is payable the earlier of quarterly or as LIBOR notes mature. The loan matures in January 2005. The interest rate on the facility is LIBOR plus 1.50% to 2.00%, depending on outstandings. A commitment fee is paid quarterly on the undrawn balance at an annual rate of 0.25% to 0.50%. At December 31, 2002, the commitment fee was 0.375% and the interest rate margin was 1.50%. The weighted average interest rates on these borrowings, excluding interest rate hedges, were 6.4% and 3.9% for the years ended December 31, 2001 and 2002, respectively. After hedging, the effective rate was 9.4% and 6.8% for the 12 months ended December 31, 2001 and 2002, respectively. At March 1, 2003, the interest rate was 3.3%, excluding interest rate hedges and 5.5% including interest rate hedges.

IPF had a $100.0 million secured revolving credit facility (the "IPF Facility"). In late December 2002, the $12.9 million balance of the IPF Facility was retired with borrowings from the Parent Facility and the facility was terminated. The IPF Facility was non-recourse to Range. The IPF Facility bore interest at LIBOR plus 1.75% to 2.25% depending on outstandings. Interest expense attributable to the IPF Facility is included in IPF expenses in the Consolidated statements of operations and amounted to $1.8 million and $937,000 for the years ended December 31, 2001 and 2002, respectively. A commitment fee was paid quarterly on the undrawn balance at an annual rate of 0.375% to 0.50%.

SUBORDINATED NOTES

The 8.75% Senior Subordinated Notes due 2007 (the "8.75% Notes") are redeemable at 104.375% of principal, declining 1.46% each January 15 to par in 2005. The 8.75% Notes are unsecured general obligations subordinated to senior debt. The 8.75% Notes are guaranteed on a senior subordinated basis by the Company's subsidiaries. Interest is payable semi-annually in January and July. During the 12 months ended December 31, 2001, the Company repurchased $42.5 million face amount of the 8.75% Notes at a discount. The cash flow reflects a $41.2 million repayment of debt relating to these repurchases. The Company also exchanged $3.4 million of the 8.75% Notes for common stock. During 2002, the Company repurchased $9.0 million face amount of the 8.75% Notes for $8.9 million. The Company also exchanged $875,000 of the 8.75% Notes for common stock. Exchanges are not reflected on the cash flow statement. The gain on these repurchases is included as an Extraordinary Gain on retirement of debt securities on the Consolidated statements of operations. The repurchased notes are held in treasury and may be reissued. As of March 1, 2003, $69.3 million of the 8.75% Notes remained outstanding.

The 6% Convertible Subordinated Debentures Due 2007 (the "6% Debentures") are convertible into common stock at the option of the holder at any time at a price of $19.25 per share. Interest is payable semi-annually in February and August. The 6% Debentures mature in 2007 and are currently redeemable at 103.0% of principal, declining 0.5% each February to 101% in 2006, remaining at that level until it becomes par at maturity. The 6% Debentures are unsecured general obligations subordinated to all senior indebtedness, including the 8.75% Notes. During 2001 and 2002, $5.7 million and $7.1 million of 6% Debentures were retired at a discount in exchange for 759,000 and 1.2 million shares of common stock, respectively. In addition, $2.3 million and $815,000 were repurchased in 2001 and 2002, respectively. Exchanges are not reflected on the cash flow statement. Extraordinary gains of $1.9 million and $1.3 were recorded in 2001 and 2002, respectively. Subsequent to December 31, 2002, the Company exchanged for 129,000 shares of common stock, an additional $880,000 face amount of the 6% Debentures. As of March 1, 2003, $20.7 million of the 6% Debentures remained outstanding.

TRUST PREFERRED - MANDITORILY REDEEMABLE SECURITIES OF SUBSIDIARY

In 1997, a special purpose affiliate, (the "Trust") issued $120 million of 5.75% Trust Convertible Preferred Securities (the "Trust Preferred"), represented by 2,400,000 shares of Trust Preferred priced at $50 a share. The Trust Preferred is convertible into common stock at a price of $23.50 per share. The Trust invested the proceeds in 5.75% convertible junior subordinated debentures issued by the Company (the "Junior Debentures"), its sole asset. The Junior Debentures and the Trust Preferred mature in November 2027. At December 31, 2001, the Junior Debentures and the related Trust Preferred are redeemable in whole or in part at 102.875% of principal declining 0.58% each November to par in 2007. The Company guarantees payments on the Trust Preferred only to the extent the Trust has funds available. Such guarantee, taken together with other obligations, provides a full subordinated guarantee of the Trust Preferred. The Company has the right to suspend distributions on the Trust Preferred for five years without triggering a default. During such suspension, accumulated distributions accrue additional interest at a rate of 5.75% per annum. The accounts of the

Trust are included in the consolidated financial statements after eliminations. Distributions are recorded as interest expense in the Statement of operations, are deductible for tax purposes, and are subject to limitations in the Parent facility as described below. In the 12 months ended December 31, 2002, $2.4 million of Trust Preferred was reacquired at a discount in exchange for 283,000 shares of common stock. In addition $2.5 million face value was repurchased at a cost of $1.5 million. An extraordinary gain of $1.8 million was recorded in 2002. In the 12 months ended December 31, 2001, $2.9 million of Trust Preferred was reacquired at a discount in exchange for 291,000 shares of common stock. In addition, $50,000 of Trust Preferred were repurchased. An extraordinary gain of $1.2 million was recorded in 2001. Subsequent to December 31, 2002, the Company repurchased $400,000 face value of the Trust Preferred for $236,000. The exchange transactions are not reflected on the cash flow statement because no cash was involved. As of March 1, 2003, $84.4 million of the Trust Preferred remained outstanding.

The debt agreements contain covenants relating to net worth, working capital, dividends and financial ratios. If certain ratio requirements are not met, payments of interest on the Trust Preferred would be restricted. The Parent facility allows the payment of common dividends on common stock, beginning January 1, 2003. The Company (including Great Lakes) was in compliance with all such covenants at December 31, 2002. Under the most restrictive covenant, $803,000 of dividends or other restricted payments could be paid at December 31, 2002.

Following is the principal maturity schedule for the long-term debt outstanding as of December 31, 2002 (in thousands):

Year-Ending December 31:	
2003	$ --
2004	--
2005	192,300
2006	--
2007	90,901
2008 -- Thereafter	84,840
	$368,041

(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. 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 option 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, 2001		December 31, 2002	
	Book	Fair	Book	Fair Value

Value
Value
Value ----
----- ----
----- ----
----- ----

Assets
Cash and
equivalents
$ 3,380 $
3,380 $
1,334 $
1,334
Marketable
securities
2,323
2,323
1,040
1,040
Commodity
swaps
52,101
52,101 17
17 -------
-- -------
-- -------
-- -------
-- Total
57,804
57,804
2,391
2,391 ----
----- ----
----- ----
----- ----

Liabilities
Commodity
swaps -- -
- (32,964)
(32,964)
Interest
rate swaps
(2,632)
(2,632)
(2,150)
(2,150)

	December 31, 2001		December 31, 2002	
	Book Value	Fair Value	Book Value	Fair Value
Long-term debt (a)	(302,491)	(292,028)	(283,201)	(279,894)
Trust Preferred (a)	(89,740)	(50,254)	(84,840)	(52,177)
Total	(394,863)	(344,914)	(403,155)	(367,185)
Net financial instruments	$(337,059)	$(287,110)	$(400,764)	$(364,794)

(a) Fair Value based on quotes received from certain brokerage houses. Quotes for December 31, 2002 were 101.0% for the 8.75% Notes, 81.5% for the 6% Debentures and 61.5% for the 5.75% Trust Preferred.

At December 31, 2002, the Company had open hedging contracts covering 64.6 Bcf of gas at prices averaging $3.96 per mcf and 1.6 million barrels of oil at prices averaging $24.45 barrel. Their fair value, represented by the estimated amount that would be realized upon termination, based on contract versus New York Mercantile Exchange ("NYMEX") price, approximated a net unrealized pre-tax loss of $32.9 million at December 31, 2002. These contracts expire monthly through December 2005. Gains or losses on open and closed hedging transactions are determined as the difference between the contract price and the reference price, generally closing prices on the NYMEX. 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. Due to additional hedging activity and rising prices, the Company estimates the net unrealized loss at March 1, 2003 was $108.7 million. Net pre-tax losses incurred relating to these derivatives for the years ended December 31, 2000, and 2001 were $43.2 million and $6.2 million, respectively. A hedging gain of $17.8 million was realized in 2002. These hedging positions are recorded on the Company's balance sheet at an estimate of fair value based on a comparison of the contract price and a reference price, generally NYMEX. Other revenues in the Consolidated statement of operations were decreased for ineffective hedging losses of $1.1 million and $2.7 million in the year-ended December 31, 2001 and 2002, respectively.

The Company had hedge agreements with Enron for 22,700 Mmbtu per day, at $3.20 per Mmbtu for the first three months of 2002. Based on accounting requirements, the Company had recorded an allowance for bad debts at year-end 2001 of $1.4 million, offset by a $318,000 ineffective gain included in 2001 income and $1.0 million gain included in OCI at year-end 2001 related to these amounts due from Enron. The gain included in OCI at year-end 2001 was included in income in the first quarter of 2002. The last of the Enron contracts expired as of March 2002.

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, 2002 (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
	December 31, 2001	14,047
		(6,193)
2002	March 31, 2002	11,726
	June 30, 2002	3,639
	September 30, 2002	3,484
	December 31, 2002	(1,059)
		17,790
Total realized gain		$ 11,597
Open Contracts		
2003	March 31, 2003	$ (8,570)
	June 30, 2003	(6,302)
	September 30, 2003	(4,839)
	December 31, 2003	(4,714)
		(24,425)
2004	March 31, 2004	(3,584)
	June 30, 2004	(2,098)
	September 30, 2004	(1,326)
	December 31, 2004	(1,055)
		(8,063)
2005	March 31, 2005	(280)
	June 30, 2005	(107)
	September 30, 2005	

(53)
December
31, 2005
(19) -----
--- (459)

Total
unrealized
loss
(32,947) -

Total
realized
and
unrealized
loss
$(21,350)
========

Interest rate swap agreements are accounted for on the accrual basis. 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 facility may be adversely affected by volatility in market interest rates. Under the Company's interest rate 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 other comprehensive income 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 income in the period incurred. At December 31, 2002, Great Lakes had interest rate swap agreements totaling $100.0 million, 50% of which is consolidated at Range. These swaps consist of five agreements totaling $35.0 million at an average rate of 4.6% which expire in June 2003, two agreements totaling $45.0 million at rates of 7.1% which expire in May 2004 and two agreements of $10.0 million each at rates of 2.3% which expire in December 2004. Range's share of the fair value of the swaps at December 31, 2002, was a hedge liability of $2.1 million based on current quotes. On December 31, 2002, the 30-day LIBOR rate was 1.4%. The Company recognized additional interest expense of $85,000, $1.1 million and $2.4 million due to interest swaps in 2000, 2001 and 2002, respectively.

The combined fair value of net losses on oil and gas hedges and net losses on interest rate swaps totaling $35.1 million appeared as Unrealized derivative gains and Unrealized derivative losses on the balance sheet at December 31, 2002. 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 2002, approximately $250,000 of costs were expensed in defense of litigation, and $385,000 reduced an accrued liability related to the period prior to the formation of Great Lakes. The Company received a $715,000 arbitration recovery, net of $72,000 of legal expenses.

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 2000, 2001 and 2002, respectively. Future minimum rental commitments under non-cancelable leases are as follows (in thousands):

2003	$1,808
2004	1,128
2005	974
2006	561
2007 and thereafter	299

	$4,770
	======

(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 1995, the Company issued $28.8 million of $2.03 Convertible exchangeable preferred stock which was convertible into common stock at a price of $9.50. The issue was retired in December 2001. The following is a schedule of changes in the number of outstanding common shares since the beginning of 2001:

	Year-Ended December 31,	
	2001	2002
Beginning Balance	49,187,682	52,643,275
Issuances:		
Employee benefit plans	372,398	417,661
Stock options exercised	223,594	

130,566
Stock
purchase
plan
263,000
168,500
Exchange
for: 8.75%
Senior
notes
779,960
182,709 6%
Debentures
758,597
1,165,700
Trust
preferred
291,211
283,200
$2.03
Preferred
766,889 --
Other (56)
-- -------
---- -----

3,455,593
2,348,336

- --------
--- Ending
Balance
52,643,275
54,991,611
===========
===========

(10) STOCK OPTION AND PURCHASE PLANS

The Company has five 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 Directors' Plan	1989 Plan	Plan	Domain Directors' Plan	1999 Plan	Total	Average Exercise Price
Outstanding at December 31, 1999	558,432	9,670	2,509,690	168,000	60,000	3,305,792	$ 7.72
Granted	--	--	--	56,000	643,200	699,200	2.12
Exercised	(98,697)	--	(246,575)	(8,000)	--	(353,272)	2.57
Expired/cancelled	(210,770)	(9,670)	(1,080,222)	(80,000)	(38,000)	(1,418,662)	8.58
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

There were options exercisable of 1,043,452 (weighted average price of $9.32), 585,526 (weighted average price of $4.04) and 975,026 (weighted average price of $4.46) at December 31, 2000, 2001 and 2002, 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. All options issued under the 1999 Plan from August 5, 1999 through May 22, 2002 vested 25% per year beginning after one year and had a maximum term of 10 years. Options issued under the 1999 Plan after May 22, 2002 vest 30%, 30% and 40%, over a three year period and have a maximum term of five years. During the year-ended December 31, 2002, 1,438,850 options were granted under the 1999 Plan at exercise prices of $4.43, $5.26 and $5.49 a share. At December 31, 2002, 2.5 million options were outstanding under the 1999 Plan at exercise prices of $1.94 to $6.67.

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 30%, 30% and 40% over a three year period and expire in five years. At December 31, 2002, 453,580 options remained outstanding under the 1989 Plan at exercise prices of $2.63 to $7.62.

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 25% per year beginning a year after grant. Effective May 22, 2002, the term of the option was changed to five years with vesting immediately upon grant. Director's options are normally granted upon election of a director or annually upon their re-election at the annual meeting. During the 12 months ended December 31, 2002, 48,000 options were granted under the Directors' Plan at exercise prices of $5.49 share. At December 31, 2002, 152,000 options were outstanding under the Directors' Plan at exercise prices of $2.81 to $6.00.

The Domain stock option plan was adopted when that company was acquired, with existing Domain options becoming exercisable into Range common stock. No options have been granted under this plan since the acquisition. At December 31, 2002, 131,702 options remained outstanding under the Plan at a price of $3.46 a share.

In total, 3.3 million options were outstanding at December 31, 2002 at exercise prices ranging from $1.94 to $7.62 as follows:

	Weighted Average		Inactive		Active		
Range of Exercise price	Exercise price	Remaining Life (Yrs)	Domain Plan	1989 Plan	Directors' Plan	1999 Plan	Total
$1.94 - $4.99	$3.36	7.0	131,702	309,655	56,000	1,132,499	1,629,856
5.00 - 9.99	6.05	6.8	--	143,925	96,000	1,412,363	1,652,288
Total			131,702	453,580	152,000	2,544,862	3,282,144

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 May 2001, shareholders approved an increase in the number of shares authorized under the Stock Purchase Plan to 1,750,000. 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 $236,000, $375,000 and $227,800 during 2000, 2001 and 2002, respectively. Through December 31, 2002, 1,289,819 shares have been sold under the Stock Purchase Plan for $5.4 million. At December 31, 2002, rights to purchase 166,500 shares were outstanding with terms expiring in May 2003.

The Company has adopted the disclosure-only provisions of SFAS No. 123, "Accounting for Stock-Based Compensation." Accordingly, no compensation cost has been recognized for the stock option plans. Had compensation cost been determined based on the fair value at the grant date for awards in 2000, 2001 and 2002 consistent with the provisions of SFAS No. 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,		
	2000	2001	2002
	(in thousands, except per share data)		
As reported - Net income	$ 36,578	$ 17,663	$ 25,766
Earnings per share -basic	0.97	0.36	0.49
-diluted	0.96	0.36	0.47
Stock-based employee compensation cost (income), net of taxes included in the determination of net income as reported	$ 2,957	$ (44)	$ 2,149
Pro forma - Net income	$ 36,412	$ 16,877	$ 24,846
Earnings per share -basic	0.97	0.35	0.47
-diluted	0.95	0.34	0.46
Stock based employee compensation cost, net of taxes, that would have been included in the determination of net income if the fair value based	$ 166	$ 786	$ 920

method had
been applied

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 2000, 2001 and 2002, respectively: fair value of $2.14, $6.50 and $4.89 per share; dividend yields of $0 per share; expected volatility factors of, 64.89, 69.80 and 166.19; risk-free interest rates of 5.5%, 5.0% and 4.9%, and an average expected life of 6 years, 6 years and nine years.

(11) DEFERRED COMPENSATION

In 1996, the Board of Directors of the Company adopted a deferred compensation plan (the "Plan"). The Plan gives certain senior employees the ability to defer all or a portion of their salaries and bonuses and invest in common stock of the Company or make other investments at the employee's discretion. The stock held in the employee benefit 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 Statement of operations. The Company recorded mark-to-market expenses related to deferred compensation of $3.4 million in 2000, a benefit of $2.4 million in 2001, and an expense of $1.1 million in 2002.

(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 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 2000, 2001 and 2002, the Company contributed $483,000, $554,000 and $602,000, at then market value, 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 available in the 401(k) Plan. Employees are encouraged to diversify out of Company stock based on their personal investment strategy.

(13) INCOME TAXES

The Company's federal income tax benefit for the years ended December 31, 2000, 2001 and 2002, was ($1.6 million), ($406,000) and ($3.4 million), respectively. A reconciliation between the statutory federal income tax rate and the Company's effective federal income tax rate is as follows (in thousands):

	Year-Ended December 31,		
	2000	2001	2002
Statutory tax rate	34%	35%	35%
Gain on retirement of securities	34	10	6
Permanent differences	11	1	(1)
Valuation allowance	(88)	(45)	(63)
State	(6)	(1)	1
Other	(14)	(4)	4
Effective tax rate	(29)%	(4)%	(18)%
Income taxes paid (refunded)	$(355)	$	

14 $ (96)
=====
=====
=====

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 (in thousands):

	December 31,	
	2001	2002
Deferred tax assets		
Net operating loss carryover	$ 53,977	$ 71,661
Allowance for doubtful accounts	7,035	4,717
Percentage depletion carryover	5,256	5,256
Net unrealized loss on hedging	--	11,388
AMT credits and other	660	665
Total deferred tax assets	66,928	93,687
Deferred tax liabilities		
Depreciation	(54,732)	(77,902)
Unrealized gain on hedging	(16,692)	--
Net deferred tax assets (liabilities)	$ (4,496)	$ 15,785

A valuation allowance on the net deferred tax asset was originally established (in years prior to 2000) due to the uncertainty of whether future taxable income would be sufficient to utilize it. Increased oil and gas prices in early 2001 allowed the reversal of the valuation allowance during the first half of 2001. Therefore, income taxes were recorded at a statutory rate for financial reporting in the second and third quarters of 2001. Due to the Company's tax loss carryover, percentage depletion carryover and AMT credits, such statutory taxes were deferred. However, due to the property impairments recorded in the fourth quarter of 2001, taxes recorded earlier in the year were reversed and no statutory provision for taxes was required in 2001. A deferred tax liability of $4.5 million is recorded on the balance sheet at year-end 2001. Without considering the tax effects of certain deferred hedging gains included in Other comprehensive income (loss) at December 31, 2001, deferred tax assets exceeded deferred tax liabilities by $12.2 million, at December 31, 2001. The inclusion of deferred tax liabilities related to OCI caused the deferred tax liabilities to exceed deferred tax assets by the amount recorded on the balance sheet and accordingly, the valuation allowance on the deferred tax asset was reversed in 2001 through a reduction of $6.1 million and an increase to OCI of $12.2 million. During 2002, the $12.2 million valuation allowance included in OCI at December 31, 2001 was reversed as the related hedge positions closed as a $11.2 million reduction of 2002 income tax expense, an $18,000 adjustment of prior-period estimates and a $960,000 increase to Capital in excess of par value. The $960,000 increase to Capital in excess of par value relates to the tax benefits of employer stock option plans. At December 31, 2002, deferred tax assets exceeded deferred tax liabilities by $15.7 million with $11.4 million of deferred tax assets related to deferred hedging losses included in OCI. Based on the Company's recent profitability and its current outlook, no valuation allowance was deemed necessary at December 31, 2002.

At December 31, 2002, the Company had regular net operating loss ("NOL") carryovers of $218.2 million and alternative minimum tax ("AMT") NOL carryovers of $198.5 million that expire between 2003 and 2022. Regular NOLs generally offset taxable income and to such extent, no income tax payments are required. To the extent that AMT NOLs offset AMT income, no alternative minimum tax payment is due. NOLs generated prior to a change-of-control are subject to limitations. The Company experienced several change of control events between 1994 and 1998 due to acquisitions. Consequently the use of $34.1 million of NOLs is limited to $10.2 million per year. Remaining NOLs are not limited. At December 31, 2002, the Company had a statutory depletion carryover of $6.6 million and AMT credit carryovers of $665,000 that are not subject to limitation or expiration.

The following table sets forth the year of expiration of NOL (pretax) carryovers which generate the largest component of the deferred tax assets listed above:

	NOL Carryover Amount	
Expiration	Regular	AMT
	(in thousands)	
2003	$ 488	$ 422
2004	666	136
2005	522	353
2006	396	277
Thereafter	216,153	197,315
Total	$ 218,225	$ 198,503

(14) EARNINGS (LOSS) 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,		
	2000	2001	2002
Numerator:			
Income before extraordinary item	$ 18,815	$ 13,712	$ 23,752
Gain on retirement of preferred stock	5,966	556	--
Preferred dividends	(1,554)	(10)	--
Numerator for earnings per share, before extraordinary item	23,227	14,258	23,752
Extraordinary item Gain on			

retirement
of
securities,
net 17,763
3,951 2,014
-------- ---
----- ------
-- Numerator
for earnings
per share,
basic and
diluted $
40,990 $
18,209 $
25,766
========
========
========
Denominator:
Weighted
average
shares
42,882
51,159
54,283 Stock
held by
employee
benefit
trust (767)
(1,002)
(1,213) ----
---- -------
- --------
Weighted
average
shares -
basic 42,115
50,157
53,070 Stock
held by
employee
benefit
trust 767
1,002 1,213
Dilutive
potential
common
shares stock
options 50
106 135 ----
---- -------
- --------
Denominator
for diluted
earnings per
share 42,932
51,265
54,418
========
========
========
Earnings per
share basic
and diluted:
Before
extraordinary
gain Basic $
0.55 $ 0.28
$ 0.45
Diluted $
0.54 $ 0.28
$ 0.44
Extraordinary
gain Basic $
0.42 $ 0.08
$ 0.04
Diluted $
0.42 $ 0.08
$ 0.03 After
extraordinary
gain Basic $

0.97 $ 0.36
$ 0.49
Diluted $
0.96 $ 0.36
$ 0.47

During 2001 and 2002, 129,000 and 160,000 stock options were included in the computation of diluted earnings per share. All remaining stock options, the 6% Debentures, Trust Preferred and the $2.03 Preferred were not included because their inclusion would have been antidilutive.

(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, 2000, 2001 and 2002, three customers accounted for 10% or more of total oil and gas revenues and the combined sales to those three customers accounted for 50%, 50% and 35% 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. Effective July 1, 2001, Great Lakes began selling its gas to several different companies, including FirstEnergy. In the year-ended December 31, 2002, approximately 92% 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 (in thousands):

	Year-Ended December 31, 2000	2001	2002
Oil and gas properties:			
Properties subject to depletion	$ 947,526	$ 1,021,898	$ 1,135,590
Unproved properties	49,523	25,731	18,959
Total	997,049	1,047,629	1,154,549
Accumulated depletion	(443,876)	(514,272)	(590,143)
Net	$ 553,173	$ 533,357	$ 564,406
Costs incurred:			
Acquisition(a)			

$ 4,701 $
9,489 $
21,790
Development
46,032 69,162
66,284
Exploration(b)
4,498 11,405
23,232 ------
----- -------
---- --------
--- Total $
55,231 $
90,056 $
111,306
===========
===========
===========

(a) Includes $1,719, $4,227 and $15,643 for oil and gas reserves, respectively; the remainder represents acreage purchases.

(b) Includes $3,187, $5,879, and $11,525 of exploration cost expensed in 2000, 2001 and 2002, respectively.

(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, 2001 and 2002 (in thousands):

	December 31, 2001	December 31, 2002
Balance Sheet:		
Current assets	$ 15,954	$ 8,356
Oil and gas properties, net	168,090	185,233
Transportation and field assets, net	15,645	15,428
Other assets	110	117
Current liabilities	9,674	16,607
Long-term debt	75,000	76,500
Members' equity	117,413	111,550
Statement of Operations:		
Revenues	$ 52,735	$ 54,310
Direct operating expense	8,413	7,996
Exploration expense	2,026	2,434
G&A expense	1,838	1,758
Interest expense	8,284	5,353
DD&A	12,182	14,258
Pretax income	17,735	20,403

With respect to certain revenue and expense items derived from the Company's 50% interest in Great Lakes, the Company makes certain reclassifications to the above items, primarily related to transportation and gathering.

(18) EXTRAORDINARY ITEM

During 2000, 5.7 million shares of common stock were exchanged for $25.0 million of Trust preferred and $13.8 million of 6% Debentures. During 2001, 1.8 million shares of common stock were exchanged for $2.9 million of Trust preferred, $5.7 million of 6% Debentures and $3.4 million of 8.75% Senior Subordinated Notes. In addition, $50,000 of Trust Preferred, $2.3 million of 6% Debentures and $42.5 million of 8.75% Senior Subordinated Notes were repurchased. During 2002, 1.6 million shares of common stock were exchanged for $2.4 million of Trust Preferred, $7.1 million of 6% Debentures and $875,000 of 8.75% Notes. In addition, $2.5 million of Trust Preferred, $815,000 of 6% Debentures and $9.0 million of 8.75% Notes were repurchased. Since 1998, there have been 15.2 million shares of common stock exchanged for convertible debt and securities in the amount of $95.8 million. In connection with these exchanges, an extraordinary gain net of costs of $17.8 million, $4.0 million and $3.1 million ($2.0 million net of taxes) was recorded in 2000, 2001 and 2002, respectively, because the securities were retired at a discount. In addition, 4.6 million and 767,000 shares of common stock were exchanged for $23.2 million and $5.4 million of the $2.03 Preferred during 2000 and 2001, respectively. In 2001, the remaining shares of $2.03 Preferred were repurchased for $74,000. The gain on retirement of debt securities was net of taxes of $0, $0 and $1.1 million in 2000, 2001 and 2002, respectively.

(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, 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.

QUANTITIES OF PROVED RESERVES

	Crude Oil and NGLs (Mbbls)	Natural Gas (Mmcf)	Natural Gas Equivalent (Mmcfe)
Balance, December 31, 1999	28,817	443,783	616,685
Revisions	(1,699)	(1,186)	(11,380)
Extensions, discoveries and additions	1,226	26,639	33,995
Purchases	226	1,605	2,961
Sales	(170)	(2,135)	(3,155)
Production	(2,398)	(41,039)	(55,427)
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
	========	========	========
PROVED DEVELOPED RESERVES			
December 31, 2000	17,215	305,796	409,086
	========	========	========
December 31, 2001	14,066	276,162	360,558
	========	========	========
December 31, 2002	17,176	320,224	423,280
	========	========	========

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.

STANDARDIZED MEASURE

	As of December 31,		
	2000	2001	2002
	(in thousands)		
Future cash inflows	$ 4,697,062	$ 1,397,897	$ 2,697,068
Future costs:			
Production	(755,727)	(471,144)	(677,214)
Development	(177,070)	(176,799)	(204,137)
Future net cash flows	3,764,265	749,954	1,815,717
Income taxes	(457,996)	(87,745)	(463,980)
Total undiscounted future net cash flows	3,306,269	662,209	1,351,737
10% discount factor	(1,800,007)	(350,801)	(852,104)
Standardized measure	$ 1,506,262	$ 311,408	$ 499,633

CHANGES IN STANDARDIZED MEASURE

As of December 31, -------

	2000	2001	2002
	(in thousands)		
Standardized measure, beginning of year	$ 503,151	$ 1,506,262	$ 311,408
Revisions:			
Prices	1,184,950	(1,076,168)	212,091
Quantities	(89,180)	(8,244)	116,757
Estimated future development cost	36,650	4,620	(31,384)
Accretion of discount	63,468	196,426	39,915
Income taxes	(130,626)	114,556	(103,529)
Net revisions	1,065,262	(768,810)	233,850
Purchases	8,003	6,245	17,815
Extensions, discoveries and additions	91,855	25,815	60,232
Production	(134,556)	(165,033)	(150,511)
Sales	(8,525)	(2,967)	(1,605)
Changes in timing and other	(18,928)	(290,104)	28,444
Standardized measure, end of year	$ 1,506,262		

$ 311,408 $
499,633
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RANGE RESOURCES CORPORATION

INDEX TO EXHIBITS

(Item 15[a 3])

Exhibit No. Description
- ----------
- ----------
- 3.1.1. Certificate of Incorporation of Lomak dated March 24, 1980 (incorporated by reference to the Company's Registration Statement (No. 33-31558)).
3.1.2. Certificate of Amendment of Certificate of Incorporation dated July 22, 1981 (incorporated by reference to the Company's Registration Statement (No. 33-31558)).
3.1.3. Certificate of Amendment of Certificate of Incorporation dated September 8, 1982 (incorporated by reference to the Company's Registration Statement (No. 33-31558)).
3.1.4. Certificate of Amendment of Certificate of Incorporation dated December 28, 1988 (incorporated by reference to the Company's Registration Statement

(No. 33-31558)).

3.1.5. Certificate of Amendment of Certificate of Incorporation dated August 31, 1989 (incorporated by reference to the Company's Registration Statement (No. 33-31558)).

3.1.6. Certificate of Amendment of Certificate of Incorporation dated May 30, 1991 (incorporated by reference to the Company's Registration Statement (No. 333-20259)).

3.1.7. Certificate of Amendment of Certificate of Incorporation dated November 20, 1992 (incorporated by reference to the Company's Registration Statement (No. 333-20257)).

3.1.8. Certificate of Amendment of Certificate of Incorporation dated May 24, 1996 (incorporated by reference to the Company's Registration Statement (No. 333-20257)).

3.1.9. Certificate of Amendment of Certificate of Incorporation dated October 2, 1996

(incorporated by reference to the Company's Registration Statement (No. 333-20257)).
3.1.10. Restated Certificate of Incorporation as required by Item 102 of Regulation S-T (incorporated by reference to the Company's Registration Statement (No. 333-20257)).
3.1.11. Certificate of Amendment of Certificate of Incorporation dated August 25, 1998 (incorporated by reference to the Company's Registration Statement (No. 333-62439)).
3.1.12 Certificate of Amendment of Certificate of Incorporation dated May 25, 2000 (incorporated by reference to the Company's Form 10-Q dated August 8, 2000).
3.2 By-Laws of the Company (incorporated by reference to the Company's Registration Statement (No. 33-31558)).
4.1 Specimen certificate of Lomak Petroleum, Inc. (incorporated by reference to the Company's Registration Statement

(No. 333-20257)). 4.2 Certificate of Trust of Lomak Financing Trust (incorporated by reference to the Company's Registration Statement (No. 333-43823)). 4.3 Amended and Restated Declaration of Trust of Lomak Financing Trust dated as of October 22, 1997 by The Bank of New York (Delaware) and the Bank of New York as Trustees and Lomak Petroleum, Inc. as Sponsor (incorporated by reference to the Company's Registration Statement (No. 333-43823)). 4.4.1 Indenture dated as of October 22, 1997, between Lomak Petroleum, Inc. and The Bank of New York (incorporated by reference to the Company's Registration Statement (No. 333-43823)). 4.4.2 First Supplemental Indenture dated as of October 22, 1997, between Lomak Petroleum, Inc. and The Bank of New York (incorporated by reference to the Company's Registration Statement (No. 333-

43823)). 4.5 Form of 5.75% Preferred Convertible Securities (included in Exhibit 4.5 above). 4.6 Form of 5.75% Convertible Junior Subordinated Debentures (included in Exhibit 4.7 above). 4.7 Convertible Preferred Securities Guarantee Agreement dated October 22, 1997, between Lomak Petroleum, Inc., as Guarantor, and The Bank of New York as Preferred Guarantee Trustee (incorporated by reference to the Company's Registration Statement (No. 333-43823)). 4.8 Common Securities Guarantee Agreement dated October 22, 1997, between Lomak Petroleum, Inc., as Guarantor, and The Bank of New York as Common Guarantee Trustee. (incorporated by reference to the Company's Registration Statement No. 333-43823)).

Exhibit No. Description - - ---------- ---- ------- 4.9 Form of Trust Indenture relating to the Senior Subordinated Notes due 2007 between Lomak Petroleum, Inc., and Fleet National Bank as trustee (incorporated on the Company' s Registration Statement (No. 333-20257)). 4.10 Credit Agreement, dated as of June 7, 1996, between Domain Finance Corporation and Compass Bank -- Houston (including the First and the Second Amendment thereto) (incorporated by reference to Exhibit 10.3 of Domain Energy Corporation's Registration Statement on Form S-1 filed with the Commission on April 4, 1997 and Exhibit 10.3 of Amendment No. 1 to Domain Energy Corporation's Registration Statement on Form S-1 filed with the Commission on May 21, 1997) (File No. 333- 24641). 4.11 Corrected Certificate of Designations of Preferred Stock of Range Resources Corporation Designated As $2.03 Convertible Exchangeable Preferred Stock, Series D (incorporated by reference to the Company's Form 10-Q dated November 6, 2000). 10.1

Incentive and Non-Qualified Stock Option Plan dated March 13, 1989 (incorporated by reference to the Company's Registration Statement (No. 33-31558)).

10.2 Advisory Agreement dated September 29, 1988 between Lomak and SOCO (incorporated by reference to the Company's Registration Statement (No. 33-31558)).

10.3.1 1989 Stock Purchase Plan (incorporated by reference to the Company's Registration Statement (No. 33-31558)).

10.3.2 Amendment to the Lomak Petroleum, Inc., 1989 Stock Purchase Plan, as amended (incorporated by reference to the Company's Registration Statement (No. 333-44821)).

10.4 Form of Directors Indemnification Agreement (incorporated by reference to the Company's Registration Statement (No. 333-47544)).

10.5.1 1994 Outside Directors Stock Option Plan (incorporated by reference to the Company's Registration Statement (No. 33-47544)).

10.5.2 1994 Outside Directors Stock Option Plan - Amendment No. 1 (incorporated by reference to the Company's Registration Statement (No. 333-40380)).

10.5.3 1994 Outside Directors Stock Option Plan - Amendment No. 2

(incorporated by reference to the Company's Registration Statement (No. 333-40380)).

10.5.4 1994 Outside Directors Stock Option Plan - Amendment No. 3 (incorporated by reference to the Company's Registration Statement (No. 333-40380)).

10.5.5 1994 Outside Directors Stock Option Plan - Amendment No. 4 (incorporated by reference to the Company's Registration Statement (No. 333-40380)).

10.6 1994 Stock Option Plan (incorporated by reference to the Company's Registration Statement (No. 33-47544)).

10.7 Registration Rights Agreement dated October 22, 1997, by and among Lomak Petroleum, Inc., Lomak Financing Trust, Morgan Stanley & Co. Incorporated, Credit Suisse First Boston, Forum Capital Markets L.P. and McDonald Company Securities, Inc., (incorporated by reference to the Company's Registration Statement (No. 333-43823)).

10.8.1 1997 Stock Purchase Plan (incorporated by reference to the Company's Registration Statement (No. 333-44821)).

10.8.2 1997 Stock Purchase Plan, as amended (incorporated by reference to the Company's Registration Statement (No.

333-44821)).
10.8.3 1997
Stock Purchase
Plan -
Amendment No. 1
(incorporated
by reference to
the Company's
Registration
Statement No.
333-40380)
10.8.4 1997
Stock Purchase
Plan -
Amendment No. 2
(incorporated
by reference to
the Company's
Registration
Statement No.
333-40380)
10.8.5 1997
Stock Purchase
Plan -
Amendment No. 3
(incorporated
by reference to
the Company's
Registration
Statement No.
333-40380) 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
the Company's
Registration
Statement (No.
333-62439)).
10.10 Domain
Energy
Corporation
1997 Stock
Option Plan for
Non-employee
Directors
(incorporated
by reference to
the Company's
Registration
Statement (No.
333-62439)).
10.11
$100,000,000
Credit
Agreement
between Range
Energy Finance
Corporation, as
Borrower, and
Credit Lyonnais
New York
Branch, as
Administrative
Agent and
Certain Lenders
dated December
14, 1999
(incorporated
by reference to
the Company's
1999 10K dated
March 20,

2000.) 10.11.1 $100,000,000 Second Amendment to Credit Agreement between Range Energy Finance Corporation, as Borrower, and Credit Lyonnais New York Branch, as Administrative Agent and Certain Lenders dated December 14, 1999 (incorporated by reference to the Company's 1999 10K dated March 20, 2000.)

Exhibit No. Description - ----------- - ----------

10.12 Purchase and Sale Agreement - Dated April 20, 2000 between Range Pipeline Systems, L.P. as Seller and Conoco Inc., as Buyer (incorporated by reference to the Company's 10-Q dated August 8, 2000).

10.13 Gas Purchase Contract - Dated July 1, 2000 between Range Production I, L.P. as Seller and Conoco Inc., as Buyer (incorporated by reference to the Company's 10-Q dated August 8, 2000).

10.14 Application Service Provider and Outsourcing Agreement - Dated June 1, 2000 between Range Resources and Applied Terravision Systems Inc. (incorporated by reference to the Company's 10-Q dated August 8, 2000).

10.15.1 $225,000,000 Amended and Restated Credit Agreement among Range Resources Corporation, as Borrower, The Lenders from Time to Time Parties Hereto, as Lenders, Bank One, Texas, N.A., as Administrative Agent, Chase

Bank of Texas, N.A., as Syndication Agent, and Bank of America, N.A., as Documentation Agent dated September 30, 1999 (incorporated by reference to the Company's 10Q dated November 10, 1999).

10.15.2 $225,000,000 First Amendment to Credit Agreement among Range Resources Corporation, as Borrower, certain parties, as Lenders, Bank One, Texas, N.A., as Administrative Agent, Chase Bank of Texas, N.A., as Syndication Agent, and Bank of America, N.A., as Documentation Agent dated September 30, 1999 (incorporated by reference to the Company's 10K dated March 7, 2001).

10.15.3 $225,000,000 Second Amendment to Credit Agreement among Range Resources Corporation, as Borrower, certain parties, as Lenders, Bank One, Texas, N.A., as Administrative Agent, Chase Bank of Texas, N.A., as Syndication Agent, and Bank of America, N.A., as Documentation Agent dated

September 30, 1999 (incorporated by reference to the Company's 10-Q dated August 8, 2000).

10.15.4 $225,000,000 Third Amendment to Credit Agreement among Range Resources Corporation, as Borrower, certain parties as Lenders, Bank One, Texas, N.A., as Administrative Agent, Chase Bank of Texas, N.A., as Syndication. Agent, and Bank of America, N.A., as Documentation Agent dated September 30, 1999 (incorporated by reference to the Company's 10-Q dated August 8, 2000).

10.15.5 $225,000,000 amended and restated Credit Agreement among Rang Resources Corporation, as Borrower, and Bank One, N.A., and the institutions named herein as lenders, Bank One, NA, as administrative agent and Banc One Capital Markets, In., as joint lead arranger and joint bookrunner and JP Morgan Chase Bank, as joint lead arranger and joint bookrunner effective May 2, 2002 (incorporated by reference to the Company's 10Q dated May 6, 2002). 10.15.6* $225,000,000 First Amendment to Credit agreement among Range Resources Corporation, as Borrowers, certain parties, as Lenders, Bank One, Texas, N.A., as Administrative Agent, Chase Bank of Texas, N.A. as Syndication Agent and Bank of America, N.A. as Documentation Agent dated December 27, 2002. 10.17 Amended and Restated Range Resources Corporation 401(k) Plan and Trust, effective January 1, 1997 including adoption agreement (incorporated by reference to the Company's 10Q dated May 6, 2002). 10.20 The Amended and Restated Deferred Compensation Plan for Director and Selected Employees effective September 1, 2000 (incorporated by reference to the Company's 10K dated March 7, 2001). 21.1* Subsidiaries of Registrant. 23.1* Consent of Independent Public Accountants. 23.2* Consent of Independent

Public Accountants.

23.3* Consent of H.J. Gruy and Associates, Inc., independent consulting petroleum engineers.

23.4* Consent of DeGoyler and MacNaughton, independent consulting petroleum engineers.

23.5* Consent of Wright and Company, independent consulting engineers.

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* Filed herewith.

EXHIBIT 10.15.6

FIRST AMENDMENT TO AMENDED AND RESTATED CREDIT AGREEMENT

THIS FIRST AMENDMENT TO AMENDED AND RESTATED CREDIT AGREEMENT (hereinafter referred to as the "First Amendment") executed as of the 27th day of December, 2002, by and among RANGE RESOURCES CORPORATION, a Delaware corporation ("Borrower") and BANK ONE, NA, a national banking association ("Bank One"), and each of the financial institutions which is a party hereto (as evidenced by the signature pages to this Amendment) or which may from time to time become a party hereto pursuant to the provisions of Section 29 of the Credit Agreement or any successor or assignee thereof (hereinafter collectively referred to as "Lenders", and individually, "Lender") and Bank One, as Administrative Agent ("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.

WITNESSETH:

WHEREAS, as of May 2, 2002, Borrower, Agent and the Lenders entered into an Amended and Restated Credit Agreement pursuant to which the Lenders made a credit facility available to Borrower (the "Credit Agreement"); and

WHEREAS, the Borrower has requested that the Lenders agree to make certain amendments to the Credit Agreement and the Lenders have agreed to do so on the terms and conditions hereinafter set forth.

NOW, THEREFORE, the parties agree to amend the Credit Agreement as follows:

1. Unless otherwise defined herein all defined terms used herein shall have the same meaning as ascribed to such terms in the Credit Agreement.

2. Section 1 of the Credit Agreement is hereby amended by deleting the reference therein to "Guarantor" and substituting the following in lieu thereof:

> "Guarantor" means GulfStar Energy, Inc., Range Energy I, Inc., Range HoldCo, Inc., Range Production Company, Range Energy Ventures Corporation and Range Energy Finance Corporation."

3. Section 13 of the Credit Agreement is hereby amended in the following respects:

(a) By deletion of the references to "REFC" in Section 13(a)(ii).

(b) By deletion of the references to "REFC" in Section 13(h)(vi).

(c) By deletion of the references to "REFC" in Section 13(i)(ii).

(d) By the addition of new Subsections 13(j)(iv) and 13(j)(v) as follows:

"(iv) loans or advances to REFC on or before December 31, 2002 not exceeding $12,900,000; or

(v) loans or advances to REFC after December 31, 2002 not exceeding at any time the lesser of (i) the total amount of cash received by Borrower from REFC or (ii) $10,000,000."

(c) By the addition of the following sentence to the end of Section 13(b), (c), (d), (e) and (f) as follows:

"GLEP and the results of its financial performance shall be excluded from the aforesaid calculation."

4. Except to the extent its provisions are specifically amended, modified or superseded by this First Amendment, the representations, warranties and affirmative and negative covenants of the Borrower contained in the Credit Agreement are incorporated herein by reference for all purposes as if copied herein in full. The Borrower hereby restates and reaffirms each and every term and provision of the Credit Agreement, as amended, including, without limitation, all representations, warranties and affirmative and negative covenants. Except to the extent its provisions are specifically amended, modified or superseded by this First Amendment, the Credit Agreement, as amended, and all terms and provisions thereof shall remain in full force and effect, and the same in all respects are confirmed and approved by the Borrower and the Lenders.

5. This First Amendment shall be effective as of the date first above written, but only upon the satisfaction of the conditions precedent set forth in Paragraph 6 hereof (the "First Amendment Effective Date").

6. The obligations of Lenders under this First Amendment shall be subject to the following conditions precedent:

(a) Execution and Delivery. The Borrower and each Guarantor shall have executed and delivered this First Amendment, and other required documents, and, REFC shall, in addition, have executed and delivered its Guaranty in the form of Exhibit "A" hereto, all in form and substance satisfactory to the Agent;

(b) Legal Opinion. The Agent shall have received from REFC's legal counsel a favorable legal opinion in form and substance satisfactory to Agent;

(c) Resolutions. The Agent shall have received appropriate certified resolutions of Borrower and each Guarantor;

(d) Good Standing. The Agent shall have received evidence of existence and good standing for Borrower and each Guarantor;

(e) Certificates of Incorporation and Bylaws. The Agent shall have received copies of Certificates of Incorporation for Borrower and each Guarantor (including REFC) together with all amendments thereto, appropriately certified by governmental authority in the jurisdiction of incorporation of Borrower and each Guarantor, and a copy of the Bylaws of Borrower and each Guarantor, and all amendments thereto, certified by one or more officers of Borrower and each Guarantor, as the case may be, as being true, correct and complete;

(f) Incumbency. To the extent not already received, the Agent shall have received a signed Certificate of Borrower and each Guarantor, certifying the names of the officers of Borrower and each Guarantor authorized to sign loan documents on behalf of Borrower and each Guarantor, together with the true signatures of each such officer. The Agent may conclusively rely on each such Certificate until the Agent receives a further Certificate of Borrower and/or any Guarantor canceling or amending the prior Certificate and submitting signatures of the officers named in such further Certificate;

(g) Payoff of Indebtedness of REFC. The Agent shall have received satisfactory evidence that all indebtedness owed pursuant to that certain Credit Agreement dated as of December 14, 1999 among Range Energy Finance Corporation, Credit Lyonnais New York Branch, and Compass Bank shall have been paid in full and all Liens given to secure the same shall have been, or shall be, within a reasonable time, released:

(h) Representations and Warranties. The representations and warranties of the Borrowers under this First Amendment are true and correct in all material respects as of such date, as if then made (except to the extent that such representations and warranties related solely to an earlier date);

(i) No Event of Default. No Event of Default shall have occurred and be continuing nor shall any event have occurred or failed to occur which, with the passage of time or service of notice, or both, would constitute an Event of Default;

(j) Other Documents. The Agent shall have received such other instruments and documents incidental and appropriate to the transaction provided for herein as the Agent or its counsel may reasonably request, and all such documents shall be in form and substance satisfactory to the Agent;

(k) Legal Matters Satisfactory. All legal matters incident to the consummation of the transactions contemplated hereby shall be reasonably satisfactory to special counsel for the Agent retained at the expense of Borrower.

7. Borrower hereby represents and warrants that all factual information heretofore and contemporaneously furnished by or on behalf of Borrower to Agent for purposes of or in connection with this First Amendment does not contain any untrue statement of a material fact or omit to state any material fact necessary to keep the statements contained herein or therein from being misleading. Each of the foregoing representations and warranties shall constitute a

representation and warranty of Borrower made under the Credit Agreement, and it shall be an Event of Default if any such representation and warranty shall prove to have been incorrect or false in any material respect at the time given. Each of the representations and warranties made under the Credit Agreement (including those made herein) shall survive and not be waived by the execution and delivery of this First Amendment or any investigation by Lenders.

8. The Borrower agrees to indemnify and hold harmless the Lenders and their respective officers, employees, agents, attorneys and representatives (singularly, an "Indemnified Party", and collectively, the "Indemnified Parties") from and against any loss, cost, liability, damage or expense (including the reasonable fees and out-of-pocket expenses of counsel to the Lender, including all local counsel hired by such counsel) ("Claim") incurred by the Lenders in investigating or preparing for, defending against, or providing evidence, producing documents or taking any other action in respect of any commenced or threatened litigation, administrative proceeding or investigation under any federal securities law, federal or state environmental law, or any other statute of any jurisdiction, or any regulation, or at common law or otherwise, which is alleged to arise out of or is based upon any acts, practices or omissions or alleged acts, practices or omissions of the Borrower or its agents or arises in connection with the duties, obligations or performance of the Indemnified Parties in negotiating, preparing, executing, accepting, keeping, completing, countersigning, issuing, selling, delivering, releasing, assigning, handling, certifying, processing or receiving or taking any other action with respect to the Loan Documents and all documents, items and materials contemplated thereby even if any of the foregoing arises out of an Indemnified Party's ordinary negligence. The indemnity set forth herein shall be in addition to any other obligations or liabilities of the Borrower to the Lenders hereunder or at common law or otherwise, and shall survive any termination of this First Amendment, the expiration of the Loan and the payment of all indebtedness of the Borrower to the Lenders hereunder and under the Notes, provided that the Borrower shall have no obligation under this section to the Lenders with respect to any of the foregoing arising out of the gross negligence or willful misconduct of the Lenders. If any Claim is asserted against any Indemnified Party, the Indemnified Party shall endeavor to notify the Borrower of such Claim (but failure to do so shall not affect the indemnification herein made except to the extent of the actual harm caused by such failure). The Indemnified Party shall have the right to employ, at the Borrower's expense, counsel of the Indemnified Parties' choosing and to control the defense of the Claim. The Borrower may at its own expense also participate in the defense of any Claim. Each Indemnified Party may employ separate counsel in connection with any Claim to the extent such Indemnified Party believes it reasonably prudent to protect such Indemnified Party. THE PARTIES INTEND FOR THE PROVISIONS OF THIS SECTION TO APPLY TO AND PROTECT EACH INDEMNIFIED PARTY FROM THE CONSEQUENCES OF STRICT LIABILITY IMPOSED OR THREATENED TO BE IMPOSED ON ANY INDEMNIFIED PARTY AS WELL AS FROM THE CONSEQUENCES OF ITS OWN NEGLIGENCE, WHETHER OR NOT THAT NEGLIGENCE IS THE SOLE, CONTRIBUTING, OR CONCURRING CAUSE OF ANY CLAIM.

9. This First Amendment may be executed in any number of counterparts and all of such counterparts taken together shall be deemed to constitute one and the same instrument.

10. WRITTEN CREDIT AGREEMENT. THE CREDIT AGREEMENT, AS AMENDED BY THIS FIRST AMENDMENT REPRESENTS THE FINAL AGREEMENT BETWEEN AND AMONG THE PARTIES AND MAY NOT BE CONTRADICTED BY

EVIDENCE OF PRIOR, CONTEMPORANEOUS OR SUBSEQUENT ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN AND AMONG THE PARTIES.

11. The Guarantors hereby consent to the execution of this First Amendment by the Borrower and reaffirms their guaranties of all of the obligations of the Borrower to the Lenders. Borrower and Guarantors acknowledge and agree that the renewal, extension and amendment of the Credit Agreement shall not be considered a novation of account or new contract but that all existing rights, titles, powers, and estates in favor of the Lenders constitute valid and existing obligations in favor of the Lenders. Borrower and Guarantors each confirm and agree that (a) neither the execution of this First Amendment or any other Loan Document nor the consummation of the transactions described herein and therein shall in any way effect, impair or limit the covenants, liabilities, obligations and duties of the Borrower and the Guarantors under the Loan Documents and (b) the obligations evidenced and secured by the Loan Documents continue in full force and effect. Each Guarantor hereby further confirms that it unconditionally guarantees to the extent set forth in their respective Guaranties the due and punctual payment and performance of any and all amounts and obligations owed to the Lenders under the Credit Agreement or the other Loan Documents.

IN WITNESS WHEREOF, the parties have caused this First Amendment to Credit Agreement to be duly executed as of the date first above written.

BORROWER:

RANGE RESOURCES CORPORATION
a Delaware corporation

By: /s/ EDDIE LEBLANC

Eddie LeBlanc, Chief Financial Officer

GUARANTORS:

RANGE ENERGY I, INC.
a Delaware corporation

By: /s/ EDDIE LEBLANC

Name: Eddie LeBlanc

Senior Vice President and
Title: Chief Financial Officer

RANGE HOLDCO, INC.
a Delaware corporation

By: /s/ EDDIE LEBLANC

Name: Eddie LeBlanc

Title: Senior Vice President and Chief Financial Officer

RANGE PRODUCTION COMPANY
a Delaware corporation

By: /s/ EDDIE LEBLANC

Name: Eddie LeBlanc

Title: Senior Vice President and Chief Financial Officer

RANGE ENERGY VENTURES
CORPORATION, a Delaware corporation

By: /s/ EDDIE LEBLANC

Name: Eddie LeBlanc

Title: Senior Vice President and Chief Financial Officer

GULFSTAR ENERGY, INC.
a Delaware corporation

By: /s/ EDDIE LEBLANC

Name: Eddie LeBlanc

Title: Senior Vice President and Chief Financial Officer

RANGE ENERGY FINANCE CORPORATION
a Delaware corporation

By: /s/ EDDIE LEBLANC

Name: Eddie LeBlanc

Title: Senior Vice President and Chief Financial Officer

LENDERS:

BANK ONE, NA, a national
banking association (Main Office Chicago)
as a Lender and Administrative Agent

By: /s/ WM. MARK CRANMER

Wm. Mark Cranmer
Director, Capital Markets

BANK OF SCOTLAND

By: /s/ ELIZABETH WILSON

Name: Elizabeth Wilson

Title: Senior Director

JPMORGAN CHASE BANK

By: /s/ ROBERT C. MERTENSOTTO

Name: Robert C. Mertensotto

Title: Managing Director

COMPASS BANK

By: /s/ JOHN M. FALBO

John M. Falbo, Senior Vice President

CREDIT LYONNAIS, NEW YORK BRANCH

By: /s/ OLIVIER AUDEMARD

Name: Olivier Audemard

Title: Senior Vice President

FLEET NATIONAL BANK

By: /s/ JEFFREY H. RATHKAMP

Name: Jeffrey H. Rathkamp

Title: Vice President

FORTIS CAPITAL CORP.

By:

Name:

Title:

By:

Name:

Title:

NATEXIS BANQUES POPULAIRES

By: /s/ DONOVAN C. BROUSSARD

Name: Donovan C. Broussard

Title: Vice President

By: /s/ LOUIS P. LAVILLE, III

Name: Louis P. Laville, III

Title: Vice President and Group Manager

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EXHIBIT 21.1

RANGE RESOURCES CORPORATION

SUBSIDIARIES OF REGISTRANT

Name ----	Jurisdiction of Incorporation ---------------	Percentage of Voting Securities Owned by Immediate Parent -----------------------
Range Production Company	Delaware	100%
Range Energy Services Company	Delaware	100%
Range Holdco, Inc.	Delaware	100%
Range Energy I, Inc.	Delaware	100%
Range Gathering & Processing Company	Delaware	100%
Range Gas Company	Delaware	100%
Lomak Financing Trust	Delaware	100%
RRC Operating Company	Ohio	100%
Range Energy Finance Corporation	Delaware	100%
Range Energy Ventures Corporation	Delaware	100%
Gulfstar Energy, Inc.	Delaware	100%
Gulfstar Seismic, Inc.	Delaware	100%
Domain Energy International Corporation	British Virgin	

Islands 100%
Energy
Assets
Operating
Company
Delaware
100%

EXHIBIT 23.1

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

The Board of Directors and Stockholders
Range Resources Corporation:

We consent to the incorporation by reference in the Registration Statements (No. 333-76837) on Form S-3, (No. 333-78231) on Form S-4 and (Nos. 333-90760, 333-63764, 333-40380, 333-30534, 333-88657, 333-69905, 333-62439, 333-44821 and 333-10719) on Form S-8 of Range Resources Corporation of our report relating to the consolidated balance sheets of Range Resources Corporation and subsidiaries as of December 31, 2002, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2002.

KPMG LLP

Dallas, Texas
March 4, 2003

EXHIBIT 23.2

CONSENT OF INDEPENDENT AUDITORS

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

/s/ ERNST & YOUNG LLP

Pittsburgh, Pennsylvania
March 5, 2003

EXHIBIT 23.3

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

We hereby consent to the use of the name H.J. Gruy and Associates, Inc., and of references to H.J. Gruy and Associates, Inc. and to the inclusion of and references to our report dated February 11, 2003, prepared for Range Resources Corporation in the Range Resources Corporation Annual Report on Form 10-K for the year-ended December 31, 2002.

H.J. GRUY AND ASSOCIATES, INC.

March 3, 2003
Houston, Texas

EXHIBIT 23.4

CONSENT OF DEGOLYER AND MACNAUGHTON

We hereby consent to the reference to our firm in your Annual Report on Form 10-K of Range Resources Corporation for the year-ended December 31, 2002, to which this consent is an exhibit. We also consent to the incorporation of information contained in our "Appraisal Report as of December 31, 2002, of Certain Interests owned by Range Resources Corporation," provided, however, that we are necessarily unable to verify the accuracy of the reserves and discounted present worth values contained therein because our estimates of reserves and discounted present worth have been combined with estimates of reserves and present worth prepared by other petroleum consultants.

DEGOLYER AND MACNAUGHTON

Dallas, Texas
March 5, 2003

EXHIBIT 23.5

CONSENT OF WRIGHT AND COMPANY

We hereby consent to the incorporation by reference of our name in the Annual Report on Form 10-K of Range Resources Corporation (the "Company") for the fiscal year-ended December 31, 2002, to which this consent is an exhibit.

WRIGHT AND COMPANY

Brentwood, Tennessee
March 5, 2003