SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A
Amendment No. 2

(MARK ONE)

{x} ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 (FEE REQUIRED)

For the fiscal year ended December 31, 2001

{ } TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 (NO FEE REQUIRED)

For the transaction period from _______ to _______

COMMISSION FILE NUMBER 0-9592

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

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

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

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

COMMON STOCK, $.01 PAR VALUE
(Title of class)

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. { }

The aggregate market value of voting stock of the registrant held by non-affiliates (excluding voting shares held by officers and directors) was $237,932,024 on March 1, 2002.

Indicate the number of shares outstanding of each of the registrant's classes of stock on March 1, 2002: Common Stock $.01 par value: 52,841,766.

DOCUMENTS INCORPORATED BY REFERENCE:
Part III of this report incorporates by reference the Proxy Statement relating to the Registrant's 2002 Annual Meeting of Stockholders, filed on April 17, 2002.

Explanatory Note

This Amendment No. 2 on Form 10-K/A to the Registrant's Form 10-K for the year ended December 31, 2001 is being filed as certain amounts in the accompanying 1999, 2000 and 2001 consolidated financial statements were restated. Other than the information affected by the restatement, all other information is presented as of the original filing on March 5, 2002.

RANGE RESOURCES CORPORATION

ANNUAL REPORT ON FORM 10-K/A AMENDMENT NO. 2
YEAR ENDED DECEMBER 31, 2001

PART I

ITEM 1. BUSINESS

GENERAL

Range Resources Corporation ("Range") is engaged in 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 and exploitation projects, acquisitions and, to a lesser extent, exploration of its extensive acreage position. All Appalachian assets are held through a 50% interest in a joint venture, Great Lakes Energy Partners L.L.C. ("Great Lakes"). Independent Producer Finance ("IPF"), a wholly owned subsidiary, provides financing to small oil and gas producers through the purchase of overriding royalty interests. Both Great Lakes and IPF are independently financed and all of IPF and Range's proportionate share of Great Lakes' assets and operations are consolidated in the Company's financial statements. At December 31, 2001, the Company had 513 Bcfe of proved reserves, having a pre-tax present value, excluding open hedging contracts, of $399.2 million based on constant prices of $20.38 per barrel and $2.63 per Mmbtu. The fair value of open hedging contracts at December 31, 2001 approximated a net unrealized pre-tax gain of $52.1 million. The Company's proved reserves are 76% natural gas by volume, 70.2% developed and 84.4% operated. At year-end, the Company's properties had a reserve life index of 9.2 years. In addition, the Company owned 558,862 gross (284,028 net) acres of undeveloped leasehold.

After ten years of rapid growth and uninterrupted profitability, Range concluded a series of disastrous acquisitions in 1997 and 1998. Due to the poor performance of the acquired properties, the Company was forced to retrench. Staff was sharply reduced, capital expenditures cut, assets sold, and a program of exchanging common stock for fixed income securities initiated. Since year-end 1998, parent company bank debt has been reduced 74% to $95.0 million. Total debt, including Trust Preferred, has been reduced 46% to $392.2 million. As a result, the Company's financial position has stabilized. The Company expects to continue to retire debt with internal cash flow and may exchange additional common stock or other equity-linked securities for indebtedness. Stockholders could be materially diluted if a substantial amount of the fixed income securities are exchanged for stock. The extent of dilution will depend on a number of factors, including the number of shares issued, the price at which stock is issued or 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 such exchanges enhance the Company's financial flexibility and should increase the market value of its common stock.

With its financial strength largely restored, the Company has refocused on increasing production and reserves. As part of this effort, the Company's exploration and production effort was placed under the control of a newly hired Executive Vice President in early 2001. Due to reserve revisions and asset sales, reserves and production fell in 1999 and 2000. In 2001, there was a slight increase in production and reserves decreased as the Company's capital program did not replace production. In 2002, the Company has announced a capital budget of $100.0 million. Due to the current low product price environment, the Company will monitor its capital expenditure program carefully and may elect not to spend the entire amount.

RESTATEMENT

In July 2002, the Company selected KPMG LLP as its new independent auditor. The Company also chose to have KPMG 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, insure the Company's ongoing access to the capital markets and to avoid any possible impediment to future transactions.

As a result of the reaudits, the Company restated the financial statements included herein. 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 reduced 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 and increased 2001 net income by $8.7 million. The changes comprising the restatement are more fully described hereafter.

HISTORY

Between 1988 and 1997, the Company actively pursued small acquisitions as well as the further development of its properties. The Company was consistently profitable and steadily increased its production and reserves. Between late 1997 and mid-1998, a series of large acquisitions were consummated which proved extremely disappointing. Production from the acquired properties fell more rapidly than anticipated and further development of the principal fields proved far less attractive than expected. In combination with a steep decline in energy prices which began in late 1997 and the substantial burden imposed by debt and fixed income securities taken on in connection with the purchases, the adverse impact on the Company's operating results, balance sheet and stock price was severe.

In 1998 and 1999, sharp reductions in staff and capital budgets, sales of properties and the formation of Great Lakes allowed the Company to materially reduce debt and stabilize its financial position. However, production and reserves fell as a result of these actions. In the Great Lakes transaction, the single most significant step in the debt reduction effort, Range and FirstEnergy Corp. ("FirstEnergy") contributed their Appalachian oil and gas properties and associated gas pipeline systems to a joint venture, forming one of the largest production companies in the region. To achieve equal ownership despite Range's contribution of a disproportionate share of the proved reserves, the venture assumed $188.3 million of Range's bank debt and FirstEnergy contributed $2.0 million of cash.

Faced with high leverage and significant concern from its banks, the Company moved aggressively to hedge its production as the oil and gas markets began to recover in late 1999. These hedges, which covered roughly 80% of the Company's anticipated production through the third quarter of 2000, were designed to assure financial viability while the restructuring was completed. Given the continuing sharp rise in oil and gas prices throughout 2000, these hedges substantially limited the benefits to the Company of the price increases. Because the Company has continued to hedge on a rolling twelve to eighteen month basis since that time, the rise in prices has permitted a substantial increase in the average price at which production is hedged, particularly since September 30, 2000. At year-end 2001, the Company had hedges in place on approximately 47.3 bcf of gas and 700,000 barrels of oil at average prices of $4.02 per mcf and $25.97 per barrel. These hedges cover approximately 55%, 30%, 15% and 5% of the Company's anticipated production from proved reserves on an mcfe basis for 2002 through 2005, respectively.

In 2000, with the benefit of rising oil and gas prices, the Company began to gradually increase capital expenditures while keeping spending below internal cash flow to allow the continued pay down of debt. Through these repayments and exchanges of common stock for fixed income securities, debt was again substantially reduced. Despite capital constraints, the Company managed to modestly increase production in the course of the year, primarily by bringing proved non-producing reserves on stream. While production rose during the year, it fell 17% from the prior year level primarily due to the impact of the Great Lakes transaction in late 1999. By mid-year 2000, the progress made in restructuring began to be recognized and the market for the Company's stock started to rebound. However, due to the lower capital expenditures the Company was unable to replace production and proved reserves fell 5.4% during the year.

In 2001, the Company increased its capital spending 84% to roughly $90.0 million. This generated a modest increase in production. The benefits of sharply higher energy prices and reduced fixed charges allowed for continued profitability and a further reduction of debt. By year-end 2001, leverage had been reduced to a more manageable level and the Company was far better positioned to pursue profitable long-term growth. The Company did not replace production in 2001 and proved reserves declined 12.1% during the year. However, the Company replaced production during the fourth quarter of 2001.

For 2002, the Company has announced a $100.0 million capital budget. Given the current low product price environment, the Company will monitor its capital expenditures carefully and may elect not to expend the entire budget. Any decline in capital spending would have an adverse affect on production and reserve replacement. Based on the authorized level of capital expenditures, the Company expects to sustain or slightly increase reserves in 2002. The 2002 budget includes $86 million for drilling and recompletions, $11 million for land and seismic and $3 million for pipelines and facilities.

During the fourth quarter of 2001, the Company recognized property impairments of $31.1 million, including $5.1 million relating to unproved acreage and $26.0 million relating to proven properties. The Company periodically compares the carrying value of its acreage to estimated fair value based on a variety of factors including geological and engineering assessments, acreage transactions in the area, the value that could be recovered from sale, farmout or exploitation, the timing of potential drilling, and the nature of the specific property. An impairment evaluation of proven properties includes estimated future cash flows including historical operating results and the estimated recoverability of reserves. (See Management's Discussion and Analysis - - Results of Operations.)

DESCRIPTION OF THE BUSINESS

Strategy

Between 1988 and 1997, assets grew from $7 million to $759 million as stockholders' equity increased from less than $1 million to $197 million. In 1998 and 1999, the Company incurred almost $200 million of losses as a result of disappointing results on a series of large acquisitions. These losses led to a series of impairments, up to and including those recorded in the fourth quarter of 2001. These losses materially reduced stockholders' equity and increased leverage. The significant improvement in oil and gas prices since mid-1999 combined with the benefits of reduced costs allowed the Company to return to profitability in 2000 and 2001. In 2001, production began to increase slightly. The 2002 capital budget of $100.0 million is expected to increase production 5% or more and expand the reserve base. The Company's hedge position, which covers approximately 50% of anticipated 2002 production from proved reserves, is expected to allow the capital program to be funded with internal cash flow even in this low price environment. However, in such a low price environment, management expects little excess cash flow to be available for reduction in debt. Should prices decline further, it would be unlikely that the Company would be able to fund its entire capital program with internal cash flow. The Company intends to monitor its capital expenditures closely and results of operations; therefore, this current low price environment may negatively affect the amount of capital spending for the year.

At year-end, the Company had almost 1,900 proven development projects in inventory. Given current oil and gas prices, the Company's hedge position and this 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 currently anticipates spending $100.0 million on capital expenditures in 2002, although, the current price environment may affect the actual level of spending. The Company's approximately 558,862 gross (284,028 net) acre undeveloped leasehold position provides 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 significant operational and technical experience. At December 31, 2001, the Company had an inventory of 1,604 proven drilling locations and 274 proven recompletions. During 2002, the Company plans to drill 161 proven locations and recomplete 41 wells. In addition, the Company also plans to drill an additional 109 not yet proven projects in 2002. The following table illustrates the activity for development projects during 2001:

	Development Projects		
	Recompletion Opportunities	Drilling Locations	Total
December 31, 2000	318	1,812	2,130
Drilled	(40)	(167)	(207)
Added	25	151	176
Deleted & other	(29)	(192)	(221)
December 31, 2001	274	1,604	1,878

Exploration. Onshore exploration projects cover 268,122 gross (106,810 net) acres. These projects target deeper horizons in existing fields as well as prospective fields in trend areas. Offshore exploration focuses on the shallow waters of the

Gulf of Mexico where 3D seismic data covering 3.5 million contiguous acres are held. The Company has offshore leases covering 174,724 gross (49,055 net) acres on which it has to date identified eleven specific projects. The Company's exploration strategy is based on limiting risk by allocating no more than 10% to 15% of the capital budget to such projects. At times, other companies pay all or a disproportionate share of exploration costs to earn an interest in a project. The Company currently anticipates participating in up to thirteen exploratory wells in 2002.

Acquisitions. After a two year period during which the Company withdrew from the acquisition market, it expects to reactivate this effort in 2002. At least initially, the focus will be on modest purchases of incremental interests in existing and adjacent properties. To the extent the acquisition effort is successfully reinitiated and capital constraints are reduced, a more substantial effort will be considered in the latter part of 2002.

DEVELOPMENT AND EXPLORATION

In 2001, the Company spent $80.6 million on oil and gas related capital expenditures, an increase of 59% over that expended in 2000. Of this amount, $35.8 million was expended in the Southwest, $22.2 million in Appalachia and $22.6 million in the Gulf Coast. These expenditures were primarily focused on placing proved non-producing reserves on stream. They funded 51 recompletions, 264 development and 8 exploratory wells, minor lease acquisitions and seismic work. Exploration and development spending brought 26.1 Bcfe of proved non-producing reserves on stream and added a net 34.4 Bcfe of new reserves. In the absence of price revisions, net reserves added during the year replaced 71% of production.

Development

Development includes recompletions, infill drilling and to a lesser extent, installation of secondary recovery projects. As described below, the Company currently has 1,878 proven recompletion opportunities and drilling locations in inventory. Drilling prospects are geographically diverse and target a mix of oil and gas, generally at depths of less than 8,000 feet. Approximately 88% of the proved development locations are concentrated in ten fields covering 824,000 gross (446,000 net) acres. The Company believes that such large acreage blocks and concentration of to be drilled wells provides economies of scale, access to competitively priced field services and focused operating and technical expertise. The following table sets forth information pertaining to the proven development inventory at December 31, 2001.

	Development Projects		
	Recompletion Opportunities	Drilling Locations	Total
Southwest	176	120	296
Gulf Coast	47	16	63
Appalachia	51	1,468	1,519
Total	274	1,604	1,878

Exploration

Onshore. The Company currently has 117 onshore exploration projects covering 268,122 gross (106,810 net) acres. Each project has multiple drilling prospects, some with several targeted formations. Given the continuing emphasis on debt reduction, it is expected that only a limited amount of work will be done on these projects in 2002.

Gulf of Mexico. The Company owns exclusive license to a 3D seismic database covering 700 contiguous blocks in the shallow water of the Gulf of Mexico, primarily offshore Louisiana. In February 2001, a joint venture was formed between the Company, Callon Petroleum Co. ("Callon") and Cheyenne Petroleum Company ("Cheyenne") to reprocess the data and utilize it to identify and capture exploration and exploitation opportunities in a 3.5 million acre area. Callon has a 50% interest in the joint venture with the Company and Cheyenne sharing the remainder. The joint venture was awarded two blocks in the March 2001 OCS lease sale. The Company's current offshore leasehold inventory totals only 174,724 gross (49,055 net) acres. To more fully exploit the 3D seismic data base, it will be necessary to lease or farm in significant additional acreage. To date, the joint venture has identified 24 specific prospects and leads on acreage not currently controlled. These projects target Miocene and Pliocene formations at depths of 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 limited number of purchasers of which three accounted for more than 10% of oil and gas revenues. These three purchasers currently accounted for 50% of oil and gas revenues in 2001. However, the Company believes that the loss of any individual customer would not have a material adverse long-term effect on the Company. 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 world economies have had, and will continue to have, a significant effect on energy prices.

On an mcfe basis, 76% of the Company's production for 2001 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 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 June 30, 2001, the joint venture sold 90% of its gas production to FirstEnergy based on closing prices on the New York Mercantile Exchange ("NYMEX") plus a basis differential. For the last six months of 2001, Great Lakes sold 33% of its gas to First Energy, with the remaining 67% being sold to eight other companies. Currently 91% of Great Lakes gas is sold 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 2001, gas revenues totaled $154.2 million or 74% of oil and gas revenues while revenues from oil and natural gas liquids totaled $54.7 million. Oil and gas revenues in 2001 increased 21% over the prior year due to a slight increase in production and substantially higher 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 decreased 35% in 2001 to $3.4 million primarily as a result of the sale of the Sterling Plant in April 2000 and lower NGL prices.

The Company's gas transportation and processing assets include (i) 50% ownership in approximately 4,600 miles of gas pipelines in Appalachia held through Great Lakes and (ii) a number of smaller gathering systems associated with the Company's producing properties. The Appalachian gathering systems transport a majority of Great Lakes' gas production as well as third party gas to major trunklines 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. Only 2% of gas production is currently sold pursuant to fixed price contracts at prices ranging from $1.25 to $4.73 per mcf (averaging $3.80 per mcf). The remaining 98% of gas production is sold at market (generally index) related prices.

HEDGING ACTIVITIES

The Company regularly enters into hedging agreements to reduce the impact on its operations of fluctuations in oil and gas prices. All such contracts are entered into solely to hedge prices and limit volatility. The Company's current policy is to hedge between 50% and 75% of its production, when futures prices justify, on a rolling twelve to eighteen month basis. Due to the exceptional gas prices in 2001, the Company extended their hedging program into 2005. At December 31, 2001, hedges were in place covering 47.3 Bcf at prices averaging $4.02 per mcf and 700,000 barrels of oil averaging $25.97 per barrel. Their fair value, excluding hedge contracts with Enron North America Corp. ("Enron"), represented by the estimated amount that would be realized on termination, approximated a net unrealized pre-tax gain of $52.1 million at December 31, 2001, which is presented on the balance sheet as a short-term gain of $37.2 million and a long-term gain of $14.9 million based on contract expiration. The contracts expire monthly through December 2005 and cover approximately 55%, 30%, 15% and 5% of anticipated 2002 through 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 a reference price, generally NYMEX. Transaction 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. Any ineffective portion of such hedges is recognized in earnings as it occurs. Net pre-tax losses relating to these derivatives in 1999, 2000 and 2001 were $10.6 million, $43.2 million, and $6.2 million, respectively. Over the last three years, the Company has recorded cumulative net pre-tax hedging losses of $60.0 million in income, which, when combined with the $52.1 million unrealized pre-tax gain at year-end 2001, result in a $7.9 million cumulative net loss. Effective January 1, 2001, the unrealized gains (losses) on these hedging positions are recorded at an estimate of fair value which the Company bases 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.

The Company had hedge agreements with Enron for 22,700 Mmbtus per day, at $3.20 per Mmbtu covering the first three months of 2002. Amounts due from Enron are not included in the open hedges described in the previous paragraph. Based on accounting regulations, the Company has recorded an allowance for bad debts at year-end 2001 of $1.4 million, offset by a $318,000 ineffective gain included in 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 will be included in income in the first quarter of 2002. The last of the Enron contracts will expire in March 2002.

INDEPENDENT PRODUCER FINANCE ("IPF")

IPF provides capital to small oil and gas producers to finance acquisition and development projects in exchange for term overriding royalty interests. The overrides are dollar-denominated and calculated to provide a contractual rate of return that typically ranges between 15% and 25%. Interest earned on the overrides is reported as IPF revenues. Almost all of the advances are for less than $5.0 million and most are for $2.0 million or less. IPF funds itself through a combination of internal cash flow and bank borrowings. At December 31, 2001, IPF's portfolio included 44 transactions having an aggregate book value of $41.4 million (net of $17.3 million of valuation allowances). The portfolio balance declined 15% in 2001 primarily due to $19.0 million of repayments received during the year. The reserves underlying IPF's royalty interests are not included in Range's consolidated reserve disclosure.

IPF provides valuation allowances against advances which may not be recoverable. Increases and decreases in the valuation allowances are reported in IPF expenses. IPF expenses include general and administrative costs and interest expense, which totaled $4.9 million and $3.6 million, respectively, in 2000 and 2001. IPF recorded valuation allowances of $603,000 in early 2000. Because of higher product prices and the resultant increase in cash receipts, IPF reversed $1.9 million of previously reserved amounts in the second half of 2000. Due to the continued favorable oil and gas prices, $1.8 million of increases in receivables were also recorded as a reduction to IPF expenses in the first nine months of 2001. However, because of lower product prices, IPF increased its reserve allowance by $2.0 million in the fourth quarter of 2001. At year-end commodity prices, the Company believes that IPFs valuation allowances were adequate.

IPF has two petroleum engineers with an average of 19 years of experience who identify and evaluate projects. The staff is responsible for defining transaction risk, assessing reserve coverage and negotiating terms. Transactions are structured to minimize risk by focusing on asset coverage and taking direct title to the royalty interests. As dollar-denominated royalties, the transactions leave a portion of the commodity price risk with the producer. However, when extreme price declines occur, as they did in 1998 and 1999, IPF is exposed to substantial losses.

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 the public securities markets; (ii) private equity and debt financing is too restrictive and expensive; and (iii) few commercial banks are interested in small energy loans as consolidation in the banking industry has raised the size threshold for lending. IPF's portfolio decreased in 2001 as a limited number of fundings were more than offset by principal repayments. IPF's bank debt is non-recourse to Range.

IPF investments involve the purchase of a term overriding royalty interest pursuant to which it receives a specified share of revenues from specific properties. The producer's obligation is non-recourse unless he fails to operate prudently, there is title failure and in certain other circumstances. Consequently, IPF's success is based on its ability to accurately estimate reserves underlying its royalty, the prices at which the production will be sold, and the operator's ability to recover the reserves on a timely and cost efficient basis. Because the override is considered a property interest, if a producer goes bankrupt, IPF's interest should be beyond the reach of creditors. If a creditor, the producer as debtor-in-possession or a trustee in a bankruptcy proceeding were to argue successfully that the transaction should be characterized as a loan, IPF may have only a creditor's claim for repayment. IPF's ownership in these production payments is a non-operated interest. While IPF is unlikely to be exposed to liabilities associated with direct working interests, such as environmental matters, personal injuries or death and property damage, such events could result in a loss of IPF's economic interest in the properties. The producer's obligation to deliver a specified share of revenues to IPF is subject to the ability of the burdened reserves to produce such revenues. As a result, IPF bears the risk that revenues will not be sufficient to amortize its investment or provide an acceptable return.

IPF was acquired in 1998. The following table summarizes IPF's historical investments:

	Year Ended December 31,				
	1997	1998	1999	2000	2001
Total advances ($000)	$40,150	$45,822	$ 4,259	$ 6,985	$11,629
Number of advances	39	75	30	26	32
Average advance ($000)	$ 1,029	$ 611	$ 142	$ 269	$ 363

INTEREST AND OTHER

The Company earns interest on cash balances and certain receivables. Interest and other income in 2000 was comprised principally of losses on property sales. The Company expects to continue to sell non-strategic properties. In 2001, Interest and other income also includes ineffective hedging gains or losses. The 2001 period included $2.3 million of the ineffective hedging gains and a $689,000 gain on asset sales partially offset by a $1.7 million writedown of marketable securities and a $1.4 million bad debt expense related to the Enron hedges. Interest and other income in 2001 amounted to $490,000, representing 0.2% of revenues.

COMPETITION

The Company encounters substantial competition in acquiring oil and gas leases, marketing its 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 will depend on its ability to identify and acquire suitable producing properties and prospects for future drilling.

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 debt outstanding in addition to its bank debt. The 8.75% senior subordinated notes, 6% convertible debentures and 5.75% trust preferred had a combined book value of $198.4 million at December 31, 2001. Their combined fair market value, based on market quotes, was $148.5 million. The Company has in the past and expects to continue in the future to exchange equity for these debt instruments. Such exchanges could have a dilutive effect on existing shareholders.

GOVERNMENTAL REGULATION

The Company's operations are affected in varying degrees 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 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 Company's cost of doing business and affects its profitability. Although the Company believes it is in substantial compliance with all applicable laws and regulations, because such laws and regulations are frequently amended or reinterpreted, the Company is unable to precisely predict the future cost or impact of complying.

THE RESTRUCTURING

A series of significant acquisitions financed principally with debt and convertible securities were completed between late-1997 and mid-1998. Due to the poor performance of the acquired properties compounded by a decline in oil and gas prices which began in late 1997, the Company was forced to take a number of steps. These included a workforce reduction, a significant decrease in capital expenditures, the sale of assets, the formation of Great Lakes and the exchange of common stock for fixed income securities. Between year-end 1998 and December 31, 2001, these initiatives reduced parent company bank debt from over $365.0 million to $95.0 million. Total debt, including trust preferred, has been reduced 46% to $392.2

million. While the Company believes its financial position has stabilized, management believes debt remains too high. To return to its historical posture of consistent profitability and growth, the Company believes it should further reduce debt. The Company expects to utilize excess cash flow to retire debt and to continue to exchange additional stock for indebtedness. Stockholders could be materially diluted if a substantial amount of fixed income securities are exchanged for stock. Since 1998, 8.2 million shares of common stock have been issued in exchange for debt and 5.4 million shares have been exchanged for $2.03 preferred stock for a total of 13.6 million shares. The shares were exchanged for $56.7 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 for a total of $85.4 million. The extent of any future dilution 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 further.

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. 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 2001, nor does it anticipate that such expenditures will be material in 2002.

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. 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. 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.

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 navigable waters. 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 Resources 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, are 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," or "projects" 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, and our ability to implement our business strategy. All such forward-looking statements in this document are expressly qualified in their entirety by the cautionary statements in this paragraph.

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 which allow it to issue additional common stock and the Company has exchanged common stock for its fixed income securities over the past three years. In 1999, 2000 and 2001, the Company exchanged common stock for 5-3/4% trust convertible 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, incorporating negotiated terms ranging from a 10% discount to a 4% premium, in 2001. In 2001, the convertible securities were acquired at discounts to their face value ranging from 4% to 44%. 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 was 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 was acquired in exchange for common stock. Since 1998, $85.4 million face value of convertible securities have been exchanged for 13,568,000 shares of common stock. See Notes 7 and 10 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 additional convertible securities is limited by the parent credit facility and the 8.75% senior subordinated notes restricted payment baskets. As of December 31, 2001, the Company has only $3.0 million available under the most restrictive basket. The amount of the restrictive baskets limit the Company's flexibility in repurchasing debt securities at attractive discounts to par, when they become available. Therefore, the Company may seek changes in these covenants.

The Company continues to review alternatives to further strengthen its balance sheet and to retire debt and convertible securities. Several alternatives involve the issuance of a large number of shares of common stock. Therefore, such alternatives could materially dilute current shareholders. The Company expects to continue to exchange common stock or other equity linked securities for its fixed income securities. While the Company anticipates reacquiring fixed income securities at a discount to face value, existing stockholders will be substantially diluted if material portions of the fixed income securities are exchanged. The extent of dilution will depend on various factors, including the number of shares issued, the price at which 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 market value of the Company's common stock. The Company's ability to consummate exchanges and the terms of the exchanges is dependent on a number of factors beyond its control, such as the level of various interest rates, the willingness of other parties to engage in transactions, state and federal regulations covering such transactions and capital market conditions.

Dividend restrictions

Restrictions on the payment of dividends and other restricted payments as defined are imposed under the Company's bank credit agreements and the 8.75% senior subordinated notes. No common dividends may be paid under the current bank agreement. Partially in response to these restrictions, a new $2.03 Convertible Exchangeable Preferred Stock Series D was authorized in September 2000. The Series D had terms substantially identical to the previously outstanding Series C except that dividends could be paid in common stock. In November 2000, 91% of the Series C was exchanged for Series D. In December 2000, 62% of the Series D was exchanged for common stock and the Company elected to pay fourth quarter 2000 Series D dividends in common stock. Fourth quarter 2000 dividends paid on the Series C amounted to only $10,000. During 2001, all remaining shares of Series D and all remaining shares of Series C were repurchased or exchanged for common stock.

The terms of the 8.75% senior subordinated notes limited 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 over the past few years, the formula provides no availability. Therefore, the Company must rely on the $20.0 million basket. At December 31, 2001, only $3.0 million of the $20.0 million basket remained available. The covenant limits the Company's flexibility in continuing to reduce debt. The Company may attempt to change this basket restriction.

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

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 by the Company in those years. By early 2001, oil and gas prices reached levels substantially above their historical norm. Since that time, prices have declined significantly. 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 55% and 30% of its anticipated production from proved reserves on an mcfe basis for 2002 and 2003, respectively and lesser amounts of 2004 and 2005 production. However, if prices rise above the level at which the hedges were entered into, they would limit the benefit of the rise in prices.

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 our exposure to adverse price movements, hedging 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.

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.

Between late 1997 and mid-1998, a series of 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 steep decline in energy prices, which began in late 1997, combined with 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 were 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 what is believed to be 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. A downward revision that occurred at year-end 2001 is unlike the previous revisions the Company has experienced. Previous revisions were associated with the disappointing performance of the properties that were acquired during the late 1990's. The entire reserve revision in 2001 is associated with the dramatic reduction in commodity prices between year-end 2000 and year-end 2001. The approximate 73% reduction in gas price on the Company's proved reserves, which are 76% gas by reserve volume, resulted in a significant revision. If there had been no change in commodity prices, the Company would have experienced a slightly positive revision. 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. That assumption is supported by the fact that performance in the fields appears to have stabilized.

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 as well as 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 continue to be written down

Accounting rules require that the carrying value of oil and gas properties be periodically reviewed for possible impairment. An "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 between late-1997 and mid-1998 and significantly decreased 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. (See Management's Discussion and Analysis - Results of Operations.) For a further discussion of accounting policies related to oil and gas properties, see Note 3 to the Consolidated Financial Statements.

We could incur substantial environmental liabilities

Our 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 the "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 9 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, 2001, the Company had a portion of its borrowings subject to interest rate swap agreements. See Note 8 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 is at floating interest rates and the other debt securities are at fixed interest rates. At December 31, 2001, the face value of the Company's fixed rate obligations totaled $198.4 million and the annual associated interest payments, based on rates in effect at that date totaled $13.9 million a year.

In addition, these obligations have certain requirements that the Company must meet to avoid the acceleration of the maturity of these instruments. See Note 7 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, limit 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 us 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 accurately estimate reserves and production rates and the operator's ability to produce and recover these 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 80% oil. Any further decline in oil prices, may cause additional increases in the IPF valuation allowance.

Acquisitions are subject to numerous risks

It generally is not feasible to review in detail every individual property acquired. 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 late 1997 and 1998, a series of acquisitions were consummated which proved extremely 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 Chairman has an interest in another oil and gas company that could compete with us

Our Chairman also serves as the Chairman and Chief Executive Officer of Patina Oil & Gas Corporation, 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. Board policies are in place that require Mr. Edelman, along with all other officers and directors, to give us notification of any potential conflicts that arise. 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 only one is currently subject to an employment contract. The loss of one or more of these individuals could have a material adverse effect on the Company.

EMPLOYEES

As of January 1, 2002, the Company had 141 full time employees, 54 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, 2001, the Company held working interests in 9,719 gross (4,743 net) productive wells and royalty interests in an additional 215 wells. Including its 50% share of Great Lakes' reserves, its properties contained, net to its interest, estimated proved reserves of 389 Bcf of gas and 21 million barrels of oil and NGL or a total of 513 Bcfe.

PROVED RESERVES

The following table sets forth estimated proved reserves over the past five years.

	December 31,				
	1997	1998	1999	2000	2001
Natural gas (Mmcf)					
Developed	369,786	436,062	299,437	305,796	276,162
Undeveloped	204,632	197,255	144,346	121,871	112,765
Total	574,418	633,317	443,783	427,667	388,927
Oil and NGL (Mbbls)					
Developed	14,971	19,649	17,884	17,215	14,066
Undeveloped	14,803	7,480	10,933	8,787	6,613
Total	29,774	27,129	28,817	26,002	20,679
Total (Mmcfe) (a)	753,062	796,091	616,685	583,679	513,001
% Developed	61.0%	69.6%	66.0%	70.1%	70.3%

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

At year-end 2001, the Company engaged the following independent petroleum consultants to evaluate its reserves: H.J. Gruy and Associates, Inc. (Southwest), DeGolyer and MacNaughton (Southwest and Gulf Coast), and Wright and Company, Inc. (Appalachia). These engineers were employed primarily based on their geographic expertise as well as their history in engineering certain properties. At December 31, 2001, these consultants collectively evaluated approximately 82% of the proved reserves set forth above. The remainder were evaluated by the 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 realized prices over the past five years (in millions).

	December 31,				
	1997	1998	1999	2000	2001
Future net revenues	$1,276	$1,020	$1,013	$3,764	$ 750
Present Value					
Pre-tax	632	555	556	1,964	399
After tax	511	517	503	1,506	311
Oil price (per barrel)	$16.00	$10.26	$23.49	$24.46	$17.59
Gas price (per mcf)	$ 2.79	$ 2.34	$ 2.34	$ 9.57	$ 2.70

Future net revenues represent future revenues from the sale of proved reserves net of production and development costs (including production and ad valorem 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, 2001. Average product prices (average of the last three days NYMEX) at December 31, 2001 were $17.59 per barrel of oil, $12.38 per barrel for natural gas liquids, and $2.70 per mcf of gas using benchmark NYMEX prices of $20.38 per barrel and $2.63 per Mmbtu. There can be no assurance that the proved reserves will be produced within the periods indicated or that prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties. No estimates of reserves have been filed with or included in reports to another federal authority or agency since year-end.

SIGNIFICANT PROPERTIES

The Company's proved reserves at December 31, 2001 were concentrated in three regions, Southwest, Gulf Coast and Appalachia. The Southwest is divided into the Permian and Midcontinent divisions. The Appalachian properties represent the Company's 50% ownership in Great Lakes. At year-end, the Company's properties included working interests in 9,719 gross (4,743 net) productive oil and gas wells and royalty interests in 215 additional wells. The Company also held interests in 558,862 gross (284,028 net) undeveloped acres. The following table sets forth summary information with respect to estimated proved reserves at December 31, 2001.

	Pre-tax Present Value				
	Amount (In thousands)	%	Oil & NGL (Mbbls)	Natural Gas (Mmcf)	Total (Mmcfe)
Southwest					
Permian	$111,156	28	13,065	68,550	146,940
Midcontinent	53,987	13	724	54,483	58,827
Subtotal	165,143	41	13,789	123,033	205,767
Gulf Coast	94,017	24	1,896	84,288	95,664
Appalachia	139,996	35	4,994	181,606	211,570
Total	$399,156	100	20,679	388,927	513,001

SOUTHWEST REGION

The Southwest region has production and field operations located in the Permian Basin of West Texas and the East Texas Basin (the Permian division) as well as in the Texas Panhandle and the Anadarko Basin of western Oklahoma (the Midcontinent division.) This region represents 41% of total reserve value and 40% of its total reserve volume. Proved reserves totaled 206 Bcfe, of which 60% was gas. The Southwest's daily production volume of 64.6 Mmcfe per day represents approximately 42% of total daily production.

At December 2001, the Southwest region properties had a development inventory of 176 proven recompletions and 120 proven drilling locations. Acreage owned by the Southwest region at December 31, 2001 included 269,242 gross (191,813 net) developed acres and 128,372 gross (107,821 net) undeveloped acres. During 2001, 42 development wells (27.4 net) were drilled, of which 38 (24.2 net) were productive. One exploratory well (one net) was drilled which was productive.

Permian. The Permian division's total proved reserves at December 31, 2001 contained 147 Bcfe, down 16% compared to year-end 2000. This change was due 90% to lower commodity prices year-over-year and 10% to poor well performance. These reserves represented 29% by volume and 28% by value of total proved reserves and were 53% oil and NGL. In the fourth quarter of 2001, net production averaged 3,612 barrels of oil and NGLs and 23.9 Mmcf of gas per day, or 45.6 Mmcfe per day in total. On an annual basis, production increased 1% to 47.6 Mmcfe per day. Producing wells total 1,347 (1,046 net), of which the Company operates approximately 90%. At December 31, 2001, the Permian division had a development inventory of 148 proven recompletions and 108 proven drilling locations. Acreage owned by the Permian division at December 31, 2001 included 68,922 gross (64,673 net) developed acres and 113,561 gross (96,890 net) undeveloped acres. In 2001, $24.9 million of capital funded the drilling of 21 development wells (14.4 net), 18 (12.2 net) were productive and one exploratory well (one net) which was productive. During the year, the division achieved an 86% drilling success rate.

In East Texas, the Permian division participated in the drilling of two gross (0.4 net) horizontal wells in the James Lime formation, a fractured carbonate. Both wells were successfully completed for combined initial rates of 13 (3.5 net) Mmcfe per day. Also in East Texas, the Company drilled its first Bossier sand test (the Linder #1). The well was unsuccessful in the Bossier formation at depths ranging from 11,500 to 12,500 feet. However, the Linder #1 was successfully recompleted uphole in the Travis Peak formation yielding rates of 3.0 (2.5 net) Mmcfe per day. To date, Range has accumulated an acreage position in East Texas totaling 34,600 (11,000 net) acres in the horizontal James Lime play and 31,600 (21,400 net) acres in the Bossier sand play. Further Bossier drilling has been deferred, pending the results of a thorough technical review; however the Company plans to continue drilling in the Travis Peak formation. At year-end 2001, acreage in East Texas was impaired by $825,000 to reflect the lack of success in the Bossier sand. (See Management's Discussion and Analysis - Results of Operations.)

In West Texas, the Permian division had disappointing drilling results in 2001 at the Powell Ranch in Glasscock County, Texas. Between 1997, when Range acquired the property, and year-end 2000, Range drilled 11 seismically identified locations with six successes for a 55% success rate. Of the five wells drilled at Powell Ranch in 2001, three were dry and two were productive. Current total net production from the field is 9.5 Mmcfe per day.

In other West Texas drilling, 5 gross (5 net) wells successfully drilled in 2001 in the Sterling Field of West Texas. Three of these wells expanded the productive limits of this field on its eastern edge. Current total net production from this field approximates 11.0 Mmcfe per day.

Midcontinent. In the Midcontinent division, total proved reserves at December 31, 2001 were 58.8 Bcfe, about the same as a year earlier. In 2001, production climbed 14% to an average of 17.0 Mmcfe per day. December 2001 production reached 19.9 Mmcfe per day as the result of successful drilling, recompletion and workover activities. During 2001, $17.8 million of capital was spent to drill 21 (13.0 net) development wells and to recomplete 10 (6.9 net) wells. Twenty (12.0 net) of the development wells proved successful, resulting in a 92% success rate.

In the Texas Panhandle, 6 (5.9 net) wells were drilled. As of December 2001, four of the wells were producing 4.5 Mmcfe per day net to Range, one of the wells was being completed and one was abandoned as a dry hole. The most significant completion in the Texas Panhandle was the Pioneer #1, which targeted the Upper Morrow sands, and is producing 4 (3.2 net) Mmcfe per day. The offsetting Pioneer #2 is currently being completed in the Upper and Lower Morrow sands. The Saturn #1, which was the only dry hole in the area, was abandoned due to lack of reservoir quality sand in the Upper Morrow.

In four trends in the Anadarko Basin, including the Sooner, Watonga Chickasha, Granite Wash and Northwest Shelf, 15 (7.8 net) wells were drilled in 2001. The only dry hole in the area was the Dalton #1, which was abandoned due to a pipe failure but later successfully redrilled. Notable in this area was the Gemini #1, which was completed in the Granite Wash and is producing in excess of 1.5 Mmcfe (1.1 net) per day. The division plans to drill at least two offsets to the Gemini #1 in 2002. In addition, a significant workover was performed on the Greene #1, which increased production to 1.8 Mmcfe per day (1.4 net). An offset to the Greene #1 is currently being drilled. The 340 (199 net) producing wells in the Midcontinent are 92% operated.

GULF COAST REGION

The Gulf Coast region represents 24% of total reserve value and 19% of total reserve volumes of the Company. Proved reserves totaled 95.7 Bcfe, down 13% from 110 Bcfe at year-end 2000. In 2001, the region only partially replaced the reserves lost through property dispositions of 2.6 Bcfe and the production of 20 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 region's wells are characterized by high initial rates and relatively short reserve lives. Production by the region represented 36% of the Company's total average daily production. Major onshore fields include Alta Mesa in Brooks County, Texas, which produces from depths of 6,000 to 7,000 in the Frio and Vicksburg formations, and Oakvale, in Jefferson Davis County, Mississippi, which produces at depths ranging from 15,000 to 16,500 feet in the Sligo and Hosston formations. Offshore properties include interests in 50 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 16 drilling locations on 155,020 gross (43,277 net) developed acres and 93,388 gross (22,245 net) undeveloped acres. At year-end 2001, the Company impaired acreage by $4.3 million and proved properties by $25.9 million in the Gulf Coast region. (See Management's Discussion and Analysis - Results of Operations.)

In 2001, the region spent $23.1 million to drill 13 (4.2 net) wells, recomplete 10 (4.1 net) others and to upgrade facilities. In addition, the division participated in the abandonment of one platform and reduced its overall plugging and abandonment exposure through assignment of its Chandeleur 37 facility and a property trade at West Delta 30. In the fourth quarter of 2001, net production averaged 782 barrels of oil and 48.6 Mmcf of gas per day or 53.3 Mmcfe per day in total. On an annual basis, production declined 4% to 55.5 Mmcfe per day due to the natural decline of mature properties. In total, the onshore properties include 56 wells (40 net), of which 77% are operated. These operated onshore properties represent 8.5% of the Company's pre-tax present value of the Gulf Coast properties at December 31, 2001. During 2001, 13 development wells (4.2 net) were drilled, of which 11 (2.7 net) were productive. Two exploratory wells (0.3 net) were drilled, of which both were productive.

A total of $5.1 million was spent at the Matagorda Island 519 offshore gas field, which is operated by BP Amoco. The Company has a 17% working interest in the field's seven wells, which produce from as deep as 16,800 feet in the lower Miocene sands. While the field is non-operated, the Company assigns technical and operational staff to study and monitor it given its significance. The field contributed 6% (3.3 Bcfe) of the Company's production in 2001. In 2000, the 519 L-3 well was drilled and turned to sales in December. In 2001, the 519 L-4 well was drilled and turned to sales in September. The initial flow rates from both wells were disappointing. To address this problem, an additional interval was opened to production in the L-3 well in September of 2001, increasing the well's rate from 5.0 to 35.0 Mmcfe per day, for a net increase to Range of 3.8 Mmcfe per day. A similar operation is currently in progress in the L-4 well. No additional drilling activity is forecast for Matagorda Island 519 in 2002. The operator has historically significantly overspent its authorized expenditures for capital projects and has consistently encountered numerous delays in completion of those projects. Largely as a result, the Company impaired Matagorda Island 519 by $8.1 million at year-end 2001. (See Management's Discussion - Results of Operations.) Other offshore activity included drilling one well each at West Cameron 206, West Cameron 192, East Cameron 33 and Mobile 864. The four wells are currently producing at a combined rate of 28.1 (5.3 net) Mmcfe per day.

Onshore, Range was active in the Hartburg play in Orange County, Texas and Calcasieu Parish, Louisiana, where five wells were drilled and one is in progress. These wells targeted Frio sands at depths of approximately 9,000 feet. The Stephenson #1, #2 and #3 as well as the Stark #2 are all online producing at a combined rate of 20.2 (2.0 net) Mmcfe per day. The one disappointment was the Lawton #1, which was abandoned after the target sands proved wet. Currently the Stephenson #4 is completing. In the Oakvale field in Mississippi, Range completed the Polk 36-3 #1 and drilled and completed the 31-7 #1 in 2001. Both wells have been fracture stimulated and are online at a combined rate of 5.5 (3.4 net) Mmcfe per day.

APPALACHIAN REGION

Through its 50% interest in Great Lakes Energy Partners L.L.C., the Company's Appalachian region represents 212 Bcfe of proved reserves, or 41% by volume and 35% by value of total proved reserves. The Appalachian Region has an interest in 8,128 gross (3,567 net) wells and 4,600 miles of gas gathering lines. Great Lakes sells its gas on a negotiated basis. Effective July 1, 2001, Great Lakes began selling its gas to several different companies, including First Energy. At December 31, 2001, Great Lakes had a development inventory of 51 proven recompletions and 1,468 proven drilling locations.

	Development Projects		
	Recompletion Opportunities	Drilling Locations	Total
December 31, 2000	74	1,635	1,709
Drilled	(8)	(142)	(150)
Added	13	148	161
Deleted	(28)	(173)	(201)
December 31, 2001	51	1,468	1,519

Acreage owned by the Appalachian region at December 31, 2001 included 730,142 gross (343,019 net) developed acres and 334,102 gross (153,962 net) undeveloped acres. During 2001, 209 development wells (86.8 net) were drilled, of which 207 (86.0 net) were productive. Five exploratory wells (1.5 net) were drilled, of which three (0.6 net) were productive. At December 31, 2001, Great Lakes operated 99% of the 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 2001, net daily production averaged 28,915 Mmcf of gas and 869 barrels of oil per day or a total of 34,128 mcfe per day. The region's properties, with 1,468 (663 net) 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, on average, producing from 10-35 years.

In 2001, $22 million in capital expenditures funded the drilling of 193.0 (84.8 net) shallow development wells, 16 (5.7 net) medium depth wells, and five (2.5 net) deep exploitation wells. In addition, capital was expended on 11 (4.2 net) recompletions as well as the purchase of 1,021 miles of 2-D and 3-D seismic data and 48,750 acres of leasehold. Out of 209 development wells drilled, 207 were successful. Three of the five exploration wells were also successful, indicating an overall 98% success rate. Production during the year averaged 32.6 Mmcfe/day net, a 4% increase. Year-end proved reserves decreased approximately 12% to 211.6 Bcfe primarily as a result of lower pricing. At year-end 2001, Great Lakes recorded an impairment of $99,000 on their Oceana property.

During 2001 exploration prospects at Great Lakes consisted of activity in the Knox Unconformity, Huntersville-Oriskany, and Trenton Black River plays. The largest effort (14 gross/12.1 net) was directed to the Knox play in Ohio. Great Lakes significantly increased its use of 3D seismic for the Knox Unconformity play in Ohio shooting or acquiring over 30 square miles of data in three separate project areas. Each of these 3D shoots yielded new discovery wells with additional drilling opportunities. Great Lakes shot a moderate amount of 2D seismic and drilled 3 gross (2 net) wells in the Huntersville/Oriskany play in Pennsylvania. While all three wells were completed, initial production rates are below expectations. In the Trenton Black River play, Great Lakes acquired leases on over 125,000 gross acres in four major prospect areas, and has plans for seismic and drilling in 2002. While Great Lakes successfully established land positions in this play, our initial drilling results were unsuccessful on all three gross (0.6 net) wells drilled in 2001.

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 plays. Production from these shallower blanket-type, tight-sand formations is characteristically long-lived with estimated ultimate production anywhere from 150-750 Mmcf per well. The three exploration plays, consisting of medium to deep wells with higher-risk and higher potential impact, include the Knox Unconformity play, the Huntersville/Oriskany Sandstone play and the Trenton Black River play. Wells drilled in the Knox Unconformity are characterized by a relatively short 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 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 of the play.

Management of Great Lakes is directed by a committee comprised of three representatives from each of the Company and FirstEnergy. Disagreements that cannot be resolved by the committee may be resolved through arbitration.

PRODUCTION

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

	Year Ended December 31,				
	1997	1998	1999 Restated	2000 Restated	2001 Restated
Production					
Gas (Mmcf)	38,409	45,193	50,808	41,039	42,278
Crude oil (Mbbl)	1,371	2,175	2,247	2,035	1,916
Natural gas liquids (Mbbl)	423	480	412	363	326
Total (Mmcfe) (a)	49,173	61,123	66,762	55,427	55,730
Revenues					
Gas	$101,217	$105,509	$108,115	$118,977	$154,175
Crude oil	24,967	26,119	33,075	47,414	49,033
Natural gas liquids	3,833	3,965	4,302	6,691	5,646
Total	130,017	135,593	145,492	173,082	208,854
Direct operating expenses (b)	31,481	39,001	43,074	40,552	43,430
Gross margin	$ 98,536	$ 96,592	$102,418	$132,530	$165,284
Average sales price(c)					
Gas (mcf)	$ 2.64	$ 2.33	$ 2.13	$ 2.90	$ 3.65
Crude oil (bbl)	18.21	12.01	14.72	23.30	25.59
Natural gas liquids (bbl)	9.06	8.26	10.44	18.43	17.33
Mcfe (a) (d)	2.64	2.22	2.18	3.12	3.75
Operating cost (mcfe)					
Direct costs	$ 0.57	$ 0.57	$ 0.58	$ 0.62	$ 0.66
Severance and production taxes	0.07	0.07	0.07	0.11	0.12
Total	$ 0.64	$ 0.64	$ 0.65	$ 0.73	$ 0.78

(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 decreased average gas prices by $0.25 per mcf, respectively. In 2000, average sales prices are net of hedging, which reduced average oil and gas prices in 2000 by $4.85 a barrel and $0.81 per mcf, respectively.

(d) Average prices realized excluding hedging were $2.34, $3.90, and $3.86 per mcfe, in 1999, 2000 and 2001, respectively.

PRODUCING WELLS

The following table sets forth information relating to productive wells at December 31, 2001. The Company owns royalty interests in an additional 215 wells. Wells are classified as oil or gas according to their predominant production stream.

	Wells		Average Working
	Gross	Net	Interest
Crude oil	1,430	965	67%
Natural gas	8,289	3,778	46%
Total	9,719	4,743	49%

ACREAGE

The following table sets forth total acreage held by the Company at December 31, 2001.

	Acres		Average Working Interest
	Gross	Net	
Developed	1,154,304	578,109	50%
Undeveloped	558,862	284,028	51%
Total	1,713,166	862,137	50%

The following table sets forth, for the preceding three years, the book value of acreage where the Company has not yet identified proved reserves (in thousands):

	1999	2000	2001
Southwest region	$50,121	$38,815	$20,906
Gulf Coast region	8,870	9,103	3,081
Appalachian region	2,821	1,605	1,743
Total	$61,812	$49,523	$25,730

DRILLING RESULTS

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

	1999		2000		2001	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	43.0	20.6	173.0	82.5	256.0	112.9
Dry	3.0	1.7	6.0	4.4	8.0	5.5
Exploratory wells						
Productive	1.0	0.5	9.0	2.9	6.0	1.9
Dry	3.0	0.8	7.0	1.7	2.0	0.9
Total wells						
Productive	44.0	21.1	182.0	85.4	262.0	114.8
Dry	6.0	2.5	13.0	6.1	10.0	6.4
Total	50.0	23.6	195.0	91.5	272.0	121.2

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 March 2006. 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.

In March 2000, a tornado struck the Company's headquarters in Fort Worth. The Company temporarily relocated to 801 Cherry Street in Fort Worth. In January 2001, the Company entered into a five-year lease for approximately 26,000 square feet of office space located at 777 Main Street in Fort Worth, and moved in April 2001. The annual lease payments on this office space will average $500,000 for the term of the lease.

The Company owns various vehicles and other equipment that is used in its field operations. Such equipment is believed to be in good repair and, while such equipment is important to its operations, it can be readily replaced as necessary.

ITEM 3. LEGAL PROCEEDINGS

The Company is involved in various legal actions and claims arising in the ordinary course of business. During 2001, the Company incurred approximately $480,000 of litigation costs for such matters. In the opinion of management, such litigation and claims are likely to be resolved without material adverse effect on its financial position or results of operations.

In February 2000, a royalty owner filed a suit asking for a class action certification against Great Lakes Energy Partners, LLC in the New York Supreme Court, alleging that gas was sold to affiliates and gas marketers at low prices, that inappropriate post production expenses reduced proceeds to the royalty owners, and that the royalty owners' share of gas was improperly accounted for. The action sought a proper accounting, an amount equal to the difference in prices paid and the highest obtainable prices, punitive damages and attorneys' fees. The case has been remanded to the state court in New York. While the outcome is still uncertain, Great Lakes believes it will be resolved without material adverse effect on its financial position or result of operations.

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

There were no matters submitted to a vote of security holders during the fourth quarter of 2001.

PART II

ITEM 5. MARKET FOR THE COMMON STOCK AND RELATED MATTERS

The Company's common stock is listed on New York Stock Exchange ("NYSE") under the symbol "RRC." Prior to August 1998, the stock was listed under the symbol "LOM." During 2001, trading volume averaged 339,141 shares per day. On March 1, 2002, the closing price of the common stock was $4.78. The following table sets forth the high and low sales prices as reported on the NYSE composite tape over the past two years.

	High	Low	Average Daily Volume
2000			
First quarter	$ 3.44	$ 1.88	230,470
Second quarter	3.31	1.44	382,015
Third quarter	5.31	2.88	366,314
Fourth quarter	7.00	4.00	339,306
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

From January 1, 2002 to March 1, 2002 the common stock has traded at prices between $4.03 and $5.09 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. The fair value of these securities, quoted from certain market makers, was $148.5 million or 75% of the par value of $198.4 million.

At various times during 2001, the Company issued common stock in exchange for fixed income securities. The shares of common stock issued in such exchanges were exempt from registration under Section 3(a)(9) of the Securities Act of 1933. During the fourth quarter of 2001, a total of $3.4 million face value amount of 8.75% Subordinated Notes was exchanged for 753,601 shares of common stock and a total of $0.5 million face value of Trust Preferred was exchanged for 60,503 shares of common stock.

HOLDERS OF RECORD

At March 1, 2002 there were approximately 2,368 holders of record of the common stock.

DIVIDENDS

Common stock dividends were initiated in 1995 and paid quarterly through the third quarter of 1999. In the first quarter of 1999, the dividend was reduced and in the fourth quarter of 1999 it was eliminated in connection with continuing losses.

In September 2000, the Company authorized a $2.03 Convertible Exchangeable Preferred Stock Series D, having terms substantially identical to the outstanding Series C Preferred, with the exception that dividends could be paid in common stock. In November 2000, 523,140 shares of Series C were exchanged for Series D on a one-for-one basis. In December 2000, 323,140 shares of Series D were exchanged for common stock. The Company elected to pay fourth quarter 2000 Series D dividends in common stock. During 2001, all remaining shares of Series D and all remaining shares of Series C were exchanged for common stock or repurchased for cash. The elimination of the $2.03 Convertible Exchangeable Preferred Stock reduced the Company's annual dividend requirement by $2.3 million.

The payment of dividends is subject to declaration by the Board of Directors and depends on earnings, capital expenditures and various other factors. The bank credit facility and the 8.75% senior subordinated notes contain restrictions on the ability to pay dividends. The bank credit facility currently prohibits common stock dividends. Under the terms of 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 the Company's losses since 1997, the Company cannot make payments under the formula and must rely on the $20.0 million basket. At December 31, 2001, $3.0 million remained available under the basket. The Company may seek to amend this basket covenant.

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,				
	1997	1998	1999	2000	2001
		(In thousands, except per share data)			
		Restated	Restated	Restated	Restated
OPERATIONS					
Revenues	$ 145,417	$ 148,929	$ 193,047	$ 184,828	$ 219,425
Net income (loss)	(23,332)	(181,273)	(23,542)	36,578	17,663
Earnings (loss) per share before extraordinary items - basic	(1.31)	(7.11)	(0.78)	0.55	0.28
Earnings (loss) per share before extraordinary items - diluted	(1.31)	(7.11)	(0.78)	0.54	0.28
Earnings (loss) per share - basic	(1.31)	(7.11)	(0.71)	0.97	0.36
Earnings (loss) per share - diluted	(1.31)	(7.11)	(0.71)	0.96	0.36
Dividends per share	0.10	0.12	0.03	--	--
BALANCE SHEET					
Working capital	$ (2,051)	$ (8,198)	$ 20,011	$ 9,665	$ 29,856
Oil and gas properties, net	623,807	653,260	570,643	553,173	533,357
Total assets	758,833	913,970	732,228	671,826	682,462
Senior debt	186,712	367,062	140,000	89,900	95,000
Non-recourse debt	--	60,100	142,520	113,009	98,801
Subordinated debt	180,000	180,000	176,360	162,550	108,690
Trust Preferred	120,000	120,000	117,669	92,640	89,740
Stockholders' equity (a)	196,950	125,669	103,238	159,944	235,621

(a) Stockholders equity includes other comprehensive income/(loss) of $370, $292, $189, $(639) and $45,523 in 1997, 1998, 1999, 2000 and 2001, respectively.

The following table sets forth summary unaudited financial information on a quarterly basis for the two years ended December 31, 2001 (in thousands, except per share data).

	2000					
	March 31		June 30		September 30	
	As Filed	Restated	As Filed	Restated	As Filed	Restated
Revenues	$42,839	$42,951	$41,336	$40,195	$44,819	$43,455
Net income (a)	4,281	6,643	8,735	9,229	7,756	7,366
Earnings per share - basic	0.12	0.19	0.23	0.25	0.19	0.18
Earnings per share - diluted	0.12	0.19	0.23	0.24	0.19	0.18
Total assets	727,214	705,885	700,439	680,566	687,500	669,147
Senior debt	142,000	142,000	112,000	112,000	99,900	99,900
Non-recourse debt	130,619	130,619	124,516	124,516	120,012	120,012
Subordinated debt	176,060	176,060	174,810	174,810	165,660	165,660
Trust Preferred	111,490	111,490	100,240	100,240	97,340	97,340
Stockholder's equity	134,164	112,715	147,900	126,793	162,371	141,062

	2000			
	December 31		Total	
	As Filed	Restated	As Filed	Restated
Revenues	$ 58,725	$ 58,227	$ 187,719	$ 184,828
Net income (a)	17,189	13,340	37,961	36,578
Earnings per share - basic	0.42	0.34	0.99	0.97
Earnings per share - diluted	0.42	0.34	0.99	0.96
Total assets	689,165	671,826	689,165	671,826
Senior debt	89,900	89,900	89,900	89,900
Non-recourse debt	113,009	113,009	113,009	113,009
Subordinated debt	162,550	162,550	162,550	162,550
Trust Preferred	92,640	92,640	92,640	92,640
Stockholder's equity	185,207	159,944	185,207	159,944

	2001					
	March 31		June 30		September 30	
	As Filed	Restated	As Filed	Restated	As Filed	Restated
Revenues	$64,202	$63,105	$59,668	$58,445	$51,671	$52,143
Net income (loss) (a)	18,512	20,053	14,740	16,968	6,689	8,198
Earnings per share - basic	0.38	0.42	0.29	0.34	0.13	0.16
Earnings per share - diluted	0.38	0.41	0.29	0.33	0.13	0.16
Total assets	676,476	658,825	712,167	695,418	739,645	584,373
Senior debt	76,800	76,800	88,800	88,800	95,000	95,000
Non-recourse debt	98,006	98,006	99,902	99,902	102,501	102,501
Subordinated debt	160,940	160,940	133,340	133,340	121,840	121,840
Trust Preferred	92,640	92,640	90,290	90,290	90,290	90,290
Stockholder's equity	175,345	151,136	243,781	222,064	266,852	247,635

	2001			
	December 31		Total	
	As Filed	Restated	As Filed	Restated
Revenues	$ 44,446	$ 45,732	$ 219,987	$ 219,425
Net income (loss) (a)	(30,945)	(27,556)	8,996	17,663
Earnings per share - basic	(0.60)	(0.54)	0.19	0.36
Earnings per share - diluted	(0.60)	(0.54)	0.19	0.36
Total assets	691,565	682,462	691,565	682,462
Senior debt	95,000	95,000	95,000	95,000
Non-recourse debt	98,801	98,801	98,801	98,801
Subordinated debt	108,690	108,690	108,690	108,690
Trust Preferred	89,740	89,740	89,740	89,740
Stockholder's equity	245,687	235,621	245,687	235,621

(a) Includes extraordinary gains on retirement of securities of $3.5 million, $7.0 million, $4.3 million and $3.0 million in the first, second, third and fourth quarters, respectively.

(b) Includes extraordinary gains on retirement of securities of $432,000 in the first quarter. These gains were $1.6 million and a loss of $396,000 in the second and third quarters, respectively. In the fourth quarter of 2001, the gain on retirement of securities was $2.3 million.

The total of the earnings per share for each quarter does not equal the earnings per share for the full year, either because the calculations are based on the weighted average shares outstanding during each of the individual periods 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.)

As described in Note 2 to the consolidated financial statements, a restatement has been made to correct previously reported financial results.

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, 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 other assumptions that are believed to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. The Company believes the following critical accounting policies affect its more significant judgments and estimates used in the preparation of its consolidated financial statements.

Proved oil and natural gas 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 as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. Estimated reserves are often subject to future revision, certain of 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 natural gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions inherently lead to adjustments of depreciation rates utilized by the Company. The Company can not predict the types of reserve revisions that will be required in future periods.

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 capital expenditures are capitalized and systematically charged to expense using the units of production method based on proved developed oil and natural gas reserves as estimated by the Company's engineers. The Company also uses proved developed reserves to recognize expense for future estimated dismantlement and abandonment costs. Costs of exploration wells in progress at year-end 2001 were not significant.

Impairment of properties - The Company continually monitors its long-lived assets recorded in Property, Plant and Equipment in the Consolidated Balance Sheet to make sure that 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 natural gas reserves that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas, and future inflation levels. 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 natural gas, unfavorable adjustment to reserves, or other changes to contracts environmental regulations or tax laws. All of these same factors must be considered when testing a property's carrying value for impairment. The Company can not predict the amount of impairment charges that may be recorded 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 months after the close of its calendar year; (b) tax returns are subject to audit by taxing authorities and audits can often take years to complete and settle; and (c) future events often impact the timing of when income tax expenses and benefits are recognized by the Company. 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 their realization. A valuation allowance is recognized for deferred tax assets when management believes that certain of these assets are not likely to be realized.

The Company's deferred tax assets exceed deferred tax liabilities at year-end 2001, before considering the effects of Other comprehensive income ("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 causes deferred tax liabilities to exceed deferred tax assets by $4.5 million therefore, such amount is recorded as deferred tax liability at year-end 2001 on the Company's balance sheet. The Company needs to earn approximately $34.8 million of pre-tax income from the unrealized hedges included in OCI at year-end before statutory taxes will be recorded on the income statement. Due to the complexity of the accounting rules regarding taxes, the timing of when the Company will record deferred taxes is uncertain.

The Company occasionally is challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in its various income tax returns. Although the Company believes that it has adequate accruals for matters not resolved with various taxing authorities, gains or losses could occur in future years from 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 interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. The Company's 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 information available to the Company.

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. The Company records a write down of marketable securities when the decline in market value is considered to be other than temporary. Impairments are recorded when management believes that a property's net book value is not recoverable based on current estimates of expected future cash flows.

FACTORS AFFECTING FINANCIAL CONDITION AND LIQUIDITY

LIQUIDITY AND CAPITAL RESOURCES

During 2001, the Company spent $89.4 million on development, exploration and acquisitions. Fixed income obligations including Trust Preferred and $2.03 Preferred, were reduced by $65.9 million. At December 31, 2001, the Company had $3.4 million in cash, total assets of $682.5 million and a debt (including Trust Preferred) to capitalization (including debt, deferred taxes and stockholders equity) ratio of 63%. Available borrowing capacity on the Company's bank lines at December 31, 2001 was $25.0 million on the Parent Facility, $25.0 million on the Great Lakes Facility and $11.2 million on the IPF Facility. Long-term debt (including Trust Preferred) at December 31, 2001 totaled $392.2 million and included $95.0 million of borrowings under the Parent Facility, $75.0 million under the non-recourse Great Lakes Facility, $23.8 million under the non-recourse IPF Facility, $79.1 million of 8.75% Senior Subordinated Notes, $29.6 million of 6% Convertible Subordinated Debentures and $89.7 million of Trust Preferred.

During 2001, 1.8 million shares of common stock were exchanged for $2.9 million of Trust Preferred, $3.4 million of 8.75% Senior Subordinated Notes and $5.7 million of 6% Debentures. In addition, $2.3 million of 6% Debentures, $42.5 million of 8.75% Senior Subordinated Notes and $50,000 of 5.75% Trust Preferred were repurchased. A $4.0 million extraordinary gain net of costs was recorded as the securities were retired at a discount. In addition, 767,000 shares of common stock were exchanged for $5.4 million of the $2.03 Preferred and the remaining were repurchased for $74,000. Since 1998, there have been 13.6 million shares of common stock exchanged for $85.4 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 twelve 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 its ability to fund capital expenditures, reduce debt and meet its 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 further. 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 obligations at December 31, 2001 and their future maturities (in thousands):

	Less than 1 Year	1 - 3 Years	After 3 Years	Total
Long term debt	$ --	$193,801*	$198,430	$392,231
Non-cancelable operating lease obligations	820	1,560	126	2,506
Total contractual cash obligations	$ 820	$195,361	$198,556	$394,737

* 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, 2001, was $392.2 million. Long-term debt of $193.8 million was at floating interest rates. Included in long-term debt was $198.4 million of debt securities which have fixed interest charges. The table below describes the Company's required annual fixed interest payments on these debt instruments (in thousands):

Security	Amount	Interest Rate	Annual Interest	Interest Payable	Maturity Dates
8.75% Sr. Sub. Notes	$79,115	8.75%	$6,900	January, July	2007
6% Debentures	29,575	6.00%	1,800	February, August	2007
5.75% Trust Preferred	89,740	5.75%	5,200	Feb., May, Aug., Nov.	2027
	$198,430		$13,900		

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 55%, 30%, 15%, and 5% of its anticipated production from proved reserves on an mcfe basis for 2002, 2003, 2004 and 2005, respectively. Decreases in prices and lower production at certain properties reduced cash flow sharply in 1998 and early 1999 and resulted in the reduction of the Company's borrowing base. Simultaneously, the Company sharply reduced its development and exploration spending. While the $89.4 million of capital expenditures for 2001 were funded entirely with internal cash flow, the amount expended was not sufficient to replace production. The 2002 capital budget of $100.0 million is expected to increase production 5% or more and expand the reserve base by more than replacing production. The Company's hedge position is expected to allow the capital program to be funded with internal cash flow even in this low price environment. However, in such a low price environment, management expects little reduction in long-term debt as excess internal cash flow will be limited. With any further decrease in product prices, it would be unlikely that the Company would be able to fund the $100.0 million capital program entirely from internal cash flow. The Company intends to closely monitor its capital expenditure program and results of operations in 2002; therefore, this current low price environment may negatively affect the amount of capital spending for the year.

Net cash provided by operations in 1999, 2000 and 2001 was $50.2 million, $74.9 million and $129.6 million, respectively. Cash flow from operations increased as higher prices and lower interest expense more than offset increasing direct operating.

Net cash used in (provided by) investing in 1999, 2000 and 2001 was $(98.2) million, $6.0 million and $78.2 million, respectively. In 1999, a $98.7 million source of cash from the formation of Great Lakes, $17.5 million in asset sales and $13.2 million of IPF receipts, more than offset additions to oil and gas properties and IPF investments. In 2000, $47.5 million of additions to oil and gas properties, offset by $25.9 million proceeds from sales of assets and $24.8 million of IPF repayments were included. 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.

Net cash used in financing in 1999, 2000 and 2001 was $146.4 million, $79.3 million and $50.6 million, respectively. Sources of financing have been primarily bank borrowings and capital raised through equity and debt offerings. 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 cash flow, proceeds from asset sales and from exchanges of common stock. During 2000, recourse debt decreased by $63.9 million and total debt (including Trust Preferred) decreased by $118.5 million. The reduction in debt was the result of applying excess cash flow and proceeds from the sale of assets to debt repayment and exchanges of common stock for fixed income securities. The amount of Trust Preferred outstanding decreased $2.3 million in 1999, $25.0 million in 2000 and $2.9 million in 2001 due primarily to exchanges of such securities into common stock.

Capital Requirements

During 2001, $89.4 million of capital was expended, primarily on development projects. This represented approximately 69% of internal cash flow. The Company manages its capital budget with the goal of funding it with internal cash flow. The 2002 capital budget of $100.0 million is expected to increase production 5% or more and expand the reserve base by more than replacing production. The Company's hedge position which covers approximately 55% of anticipated 2002 production from proved reserves, is expected to allow the capital program to be funded with internal cash flow even in this low price environment. However, in such a low price environment, management expects little reduction in long-term debt as excess internal cash flow will be limited. With any further decrease in product prices, it would be unlikely that the Company would be able to fund the $100.0 million capital program entirely from internal cash flow. The Company intends to closely monitor the capital expenditure program and results of operations; therefore, this current low price environment may negatively affect the amount of capital spending for the year. 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 three separate revolving credit facilities: a $225.0 million facility at the parent company; a $100.0 million facility at IPF and a $275.0 million facility at Great Lakes. Each facility is secured by substantially all of the assets of the borrower. The IPF and Great Lakes facilities are non-recourse to Range. As Great Lakes is 50% owned, half of the borrowings on its facility are consolidated in Range's financial statements.

Availability under the facilities are subject to borrowing bases set by 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, 2002, there was availability under each of the Company's facilities. At the parent, a $120.0 million borrowing base was in effect of which $16.5 million was available. At IPF, a $35.0 million borrowing base was in effect of which $11.7 million was available. At Great Lakes, half of which is consolidated at Range, a $200.0 million borrowing base was in effect, of which $54.0 million was available.

Hedging

Oil and Gas Prices

The Company regularly enters into hedging agreements to reduce the impact of fluctuations in oil and gas prices on its operations. The Company's current policy, when futures prices justify, is to hedge between 50% and 75% of projected production from existing proved reserves on a rolling twelve to eighteen month basis. At December 31, 2001, hedges were in place covering 47.3 Bcf of gas at prices averaging $4.02 per mcf and 700,000 barrels of oil averaging $25.97 per barrel. Their fair value, excluding hedge contracts with Enron North America Corp. ("Enron"), represented by the estimated amount that would be realized on termination, based on contract versus NYMEX prices, approximate a net unrealized pre-tax gain of $52.1 million at December 31, 2001, respectively. The contracts expire monthly through December 2005 and cover approximately 55% of anticipated 2002 production from proved reserves and 30% of 2003 production from proved reserves and lesser amounts of 2004 and 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. Any ineffective portion of such hedges is recognized in earnings as it occurs. Net pre-tax losses relating to these derivatives in 1999, 2000 and 2001 were $10.6 million, $43.2 million and $6.2 million, respectively. Over the last three years, the Company has recorded cumulative net pre-tax hedging losses of $60.0 million in income, which, when combined with the $52.1 million unrealized pre-tax gain at year-end 2001, result in a cumulative net loss of $7.9 million. Effective January 1, 2001, the unrealized gains (losses) on these hedging positions are recorded at an estimate of fair value which the company bases on a comparison of the contract price and a reference price, generally NYMEX, on the Company's balance as OCI, a component of Stockholders' Equity.

The Company had hedge agreements with Enron for 22,700 Mmbtu's per day, at $3.20 per Mmbtu for the first three months of 2002. Amounts due from Enron are not included in the open hedges described in the previous paragraph. Based on accounting regulations, the Company has 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 will be included in income in the first quarter of 2002. The last of the Enron contracts will expire as of March 2002.

Interest Rates

At December 31, 2001, Range had $392.2 million of debt (including Trust Preferred) outstanding. Of this amount, $198.4 million bears interest at fixed rates averaging 7.0%. Senior debt and non-recourse debt totaling $193.8 million bears interest at floating rates, which averaged 4.0% at year-end 2001, excluding interest rate swaps. At December 31, 2001, Great Lakes had $100.0 million of interest rate swap agreements, of which 50% is consolidated at Range. Two agreements totaling $45.0 million at rates of 7.1% each expire in May 2004. Two agreements of $10.0 million each at 6.2% in December 2002 and five agreements totaling $35.0 million at rates of 4.8%, 4.7%, 4.6%, 4.5%, and 4.5% expire in June 2003. The agreements expiring in May 2004 may be terminated at the counter party's option in May 2002. The 30-day LIBOR rate on December 31, 2001 was 1.9%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2001 would cost the Company approximately $1.4 million in additional annual interest, net of swaps.

Capital Restructuring Program

As described in Note 1 to the Consolidated Financial Statements, 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 $95.0 million and total debt (including Trust Preferred) to $392.2 million at December 31, 2001. While the Company believes its financial position has stabilized, management believes debt remains too high. To return to its historical posture of consistent profitability and growth, the Company believes it should further reduce debt. The Company currently believes it has sufficient liquidity and cash flow to meet its obligations for the next twelve months; however, a drop in oil and gas prices or a reduction in production or reserves would reduce the Company's ability to fund capital expenditures and meet its financial obligations.

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 2001, the Company received an average of $25.59 per barrel of oil and $3.65 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. While product prices have recently declined, the cost of services in the oil and gas industry have not declined by the same percentage. Any increases in product prices could cause inflationary pressures specific to the industry to also increase.

RESULTS OF OPERATIONS

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

	Year Ended December 31,		
	1999	2000	2001
	(in thousands)		
	Restated	Restated	Restated
Increase/(Decrease) in Revenues:			
Writedown of marketable securities	$ --	$ --	$ (1,715)
Enron bad debt expense	--	--	(1,352)
Gain/(Loss) from asset sales	(530)	(1,116)	689
Effect of SFAS 133	--	--	2,351
Hedging gains (losses)	(10,631)	(43,187)	(6,194)
Gain on sale - Great Lakes	30,929	--	--
	$ 19,768	$(44,303)	$ (6,221)
Increase/(Decrease) in Expenses:			
Provision for impairment	$ 29,901	$ --	$ 31,085
Mark-to-market non-cash compensation expense	160	3,405	(2,410)
Bad debt expense	--	615	688
Effect of SFAS 133	--	--	1,332
Adjustment of IPF valuation allowance	564	(2,891)	122
	$ 30,625	$ 1,129	$ 30,817
Extraordinary Items:			
Gain on retirement of securities	$ 2,430	$ 17,763	$ 3,951

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 period. Revenues benefited from a 20% increase in average prices per mcfe to $3.75. The average prices 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 labor and services and supplies. Therefore, 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 June 2000 and lower NGL prices. IPF's $6.6 million of revenues declined 7% from 2000. IPF records income from payments on accounts with no reserve accrued against them. On accounts with reserves, IPF reduces the carrying value of the account for payments received and does not record income. Due to declining prices 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 at the time, was more than offset by a year-end increase in reserve for doubtful accounts 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 $1.3 million was recorded to IPF loss reserves and a favorable $1.6 million adjustment to the reserve for doubtful accounts.

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.

Interest and 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 writedown of marketable securities and a $1.4 million bad debt expense related to the Enron hedges. The 2000 period included $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.

Depletion, depreciation and amortization ("DD&A") increased 16% to $77.6 million as a result of the mix of production between depletion pools and higher depletion rates. The per mcfe DD&A rate in 2001 was $1.39, a $0.18 increase from the $1.21 rate in 2000. The DD&A rate is determined based on ending reserves (valued at prices management believed appropriate at the time) and the net book value associated with them and to a lesser extent, depreciation on other assets owned at year-end. The DD&A rate in the fourth quarter of 2001 was $1.60 per mcfe. The Company currently estimates that the consolidated DD&A rate for 2002 will approximate $1.38 per mcfe.

The Company recorded a provision for impairment on acreage and proved properties for the year ended 2001. In evaluating possible impairment, the Company evaluates acreage on a separate basis from proved properties.

Acreage. 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 properties to the assessment of value that could be recovered from sale, farm-out or exploitation. The Company considers other additional information it believes is relevant in evaluating the properties' fair value, such as geological assessment of the area, other acreage purchases in the area, timing of the associated drilling program or the properties' uniqueness. The following acreage was impaired for the reasons indicated (in thousands):

Acreage Pool	Reason for Impairment	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

Proved Properties. The impairment evaluation on proven properties is based on proved reserves. Estimated future cash flows include revenues from anticipated oil and production, severance taxes, direct operating expenses and capital costs. The following properties were impaired based upon an analysis of future cash flows (in thousands):

Property Pool	Reason for Impairment	Impairment Amount
Matagorda Island 519	Decline in gas price	$ 14,401
Offshore Other	Decline in gas price	3,302
Gulf Coast Onshore	Decline in gas price	8,542
Oceana (GLEP)	Decline in oil price	99
Total		$ 25,944

Comparison of 2000 to 1999

Net income in 2000 totaled $36.6 million, compared to a net loss of $23.5 million in 1999. Production fell to 151,442 mcfe per day, a 17% decrease from 1999. A 4% decrease would have been reported if the effect of the Great Lakes transaction were eliminated. Revenues benefited from a 43% increase in average prices per mcfe to $3.12, partially offset by the production decrease. The average prices received for oil increased 58% to $23.30 per barrel and for gas increased 36% to $2.90 per Mcf.

Production expenses fell 6% to $40.6 million largely as a result of the Great Lakes transaction and asset sales. Operating costs per mcfe produced averaged $0.65 in 1999 versus $0.73 in 2000 due to higher production taxes and workovers.

Transportation, processing and marketing revenues decreased 32% to $5.3 million as benefits of higher NGL prices were more than offset by the impact of the Sterling gas plant sale in April 2000. IPF's $7.2 million of revenues consisted of the return portion of its royalties. IPF's income declined 16% over that reported in 1999. During 2000, IPF expenses included $1.5 million of administrative costs, $3.4 million of interest, a $1.3 million favorable adjustment to IPF reserves and a $1.6 million favorable adjustment to the reserve for doubtful accounts.

Exploration expense increased 32% to $3.2 million, primarily due to higher dry hole costs.

General and administrative expenses increased 70% to $14.9 million. The increase was primarily due to an increase in non-cash mark-to-market compensation expense of $3.2 million and lower recoupments from third parties for operations which fell due to the Great Lakes transaction, the expense of establishing duplicate financial and administrative departments in Fort Worth and higher bad debt expenses.

Interest and other income decreased $1.1 million primarily due to $1.1 million of losses on sales of assets. Interest expense (excluding IPF) decreased 15% to $40.0 million primarily as a result of the lower outstandings, partially offset by higher interest rates. The average outstanding balance on the bank credit facility fell to $125 million from $308 million in the prior year and the weighted average interest rate rose from 7.1% to 8.8%.

Depletion, depreciation and amortization ("DD&A") decreased 17% as a result of the mix of production by depletion pool and lower production. The Company-wide DD&A rate was $1.21 per mcfe in 2000 compared to $1.21 in 1999. Acreage is assessed periodically to determine whether there has been an impairment. If an impairment is indicated, a loss is recognized. The Company compares the carrying value of its acreage to estimated fair value based on a variety of factors including the value that could be recovered from sale, farm-out, or exploitation, a geological and engineering assessment, acreage transactions in the area, the timing of potential drilling and the nature of the specific property. In the fourth quarter of 2000, the Company raised its DD&A rate to $1.34 per mcfe to reflect a decline in proved reserves and the increased book value of properties subject to amortization. Reserves were revised downward in 2000 due to the removal of drilling and recompletion locations that, based on perceived risk, will probably not be drilled. See Note 22 to the financial statements. The Company's high DD&A rate will make it more difficult to remain profitable if commodity prices fall sharply.

The Company recorded a provision for impairment on acreage ($6.1 million), proved properties ($2.8 million) and a gas plant ($21.0 million) for the year ended 1999. In evaluating possible impairment, the Company evaluates acreage on a separate basis from proved properties.

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 Range'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 Range views and manages its ongoing market risk exposures. All of Range's market risk sensitive instruments were entered into for purposes other than trading.

Commodity Price Risk. Range's major market risk is exposure to oil and gas pricing. Realized pricing is 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 of proved reserves. Pursuant to these swaps, Range receives a fixed price for its production and pays market prices to the contract counterparty. This 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, 2001, Range had oil and gas hedges in place covering 47.3 Bcf of gas and 700,000 barrels of oil. Their fair value, excluding hedge contracts with Enron, represented by the estimated amount that would be realized upon termination, based on contract versus NYMEX prices, approximated a net unrealized pre-tax gain of $52.1 million at December 31, 2001. These contracts expire monthly through December 2005 and cover approximately 55% of anticipated 2002 production from proved reserves and 30% of 2003 production from proved reserves and lesser amounts of 2004 and 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 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 1999, 2000 and 2001 were $10.6 million, $43.2 million and $6.2 million, respectively. 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 Mmbtu's per day, at $3.20 per Mmbtu for the first three months of 2002. Amounts due from Enron are not included in the open hedges described in the previous paragraph. Based on its accountants guidance, the Company has 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 will be included in income in the first quarter of 2002. The last of the Enron contracts will expire as of March 2002.

In 2001, a 10% reduction in oil and gas prices, excluding amounts fixed through hedging transactions, would have reduced revenue by $4.4 million. If oil and gas future prices at December 31, 2001 had declined by 10%, the unrealized hedging gain at that date would have increased by $15.2 million.

At December 31, 2001, Range had $392.2 million of debt (including Trust Preferred) outstanding. Of this amount, $198.4 million bears interest at fixed rates averaging 7.0%. Senior debt and non-recourse debt totaling $193.8 million bears interest at floating rates, excluding interest rate swaps, which averaged 4.0% at that date. At December 31, 2001, Great Lakes had interest rate swap agreements totaling $100.0 million, 50% of which is consolidated with Range. Two agreements totaling $45.0 million at rates of 7.1% each expire in May 2004. Two agreements of $10.0 million each at 6.2% expire in December 2002 and five agreements totaling $35.0 million at rates of 4.8%, 4.7%, 4.6%, 4.5% and 4.5% expire in June 2003. The agreements expiring in May 2004 may be terminated at the counterparty's option in May 2002. On December 31, 2001, the 30-day LIBOR rate was 1.9%. A 1% increase in short-term interest rates on the floating-rate debt outstanding (net of amounts fixed through hedging transactions) at December 31, 2001 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

In July 2002, the Company appointed KPMG LLP as its new independent auditor.

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 Company's 2001 annual stockholders' meeting of stockholders. Officers are appointed by the Board of Directors.

	AGE	OFFICE HELD SINCE	POSITION
Thomas J. Edelman	51	1988	Chairman and Chairman of the Board
John H. Pinkerton	47	1990	President and Director
Robert E. Aikman	70	1990	Director
Anthony V. Dub	52	1995	Director
V. Richard Eales	65	2001	Director
Allen Finkelson	55	1994	Director
Alexander P. Lynch	49	2000	Director
James E. McCormick	74	2000	Director
Terry W. Carter	49	2001	Executive Vice President - Exploration and Production
Eddie M. LeBlanc III	53	2000	Senior Vice President and Chief Financial Officer
Herbert A. Newhouse	57	1998	Senior Vice President - Gulf Coast
Chad L. Stephens	46	1990	Senior Vice President - Southwest
Rodney L. Waller	52	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, Mr. Edelman served as a director and President of Snyder Oil Corporation ("SOCO"), a publicly traded independent oil and gas 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 his Bachelor of Arts Degree from Princeton University and his Masters Degree 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 Degree in Business Administration from Texas Christian University and his Master of Arts Degree in Business Administration from the University of Texas. Mr. Pinkerton is a director of Venus Exploration, Inc., a publicly traded exploration and production company in which Range owned approximately a 18% interest at December 31, 2001.

Robert E. Aikman, became a Director in 1990. Mr. Aikman has more than 40 years experience in petroleum and natural 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 also Chairman of Provident Communications, Inc., Vice-Chairman of Whamtech, Inc., and President of The Hawthorne Company, an entity which organizes joint ventures and provides advisory services for the acquisition of oil and gas properties, including the financial restructuring, reorganization and sale of 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 graduated from the University of Oklahoma in 1952.

Anthony V. Dub became a Director in 1995. Mr. Dub is Chairman of Indigo Capital, LLC, a financial advisory firm based in New York City. Prior to forming Indigo Capital in 1997, he served as an officer of Credit Suisse First Boston, an investment banking firm. Mr. Dub joined Credit Suisse First Boston in 1971 and was named a Managing Director in 1981. Mr. Dub received his Bachelor of Arts Degree from Princeton University in 1971.

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 a Bachelor of Arts Degree from St. Lawrence University and a Doctor of Laws Degree 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.

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 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 that was acquired by Beacon in 1997. Prior to 1991, Mr. Lynch served as a Managing Director with Lehman Brothers, a division of Shearson Lehman Brothers, Inc. Mr. Lynch received a Bachelor of Arts degree from the University of Pennsylvania and a Master's Degree from the Wharton School of Business at the University of Pennsylvania.

James E. McCormick became a Director in 2000. Mr. McCormick has more than 40 years experience in the oil and gas industry. He currently serves as Director of Lone Star Technologies, TESCO Corporation and Dallas National Bank. He served as a Director for Santa Fe Snyder Corporation until its merger with Devon Energy in August 2000. Mr. McCormick served as President and Chief Operating Officer for Oryx Energy Company from its inception in 1988 until his retirement in 1992. Prior to his position at Oryx, he served as President and Chief Executive Officer of Sun Exploration and Production Company. Mr. McCormick received a Bachelor of Science degree in Geology from Boston University.

Terry W. Carter, Executive Vice President-Exploration and Production, joined the Company in January 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 Energy Mr. LeBlanc served as Senior Vice President and Chief Financial Officer. Mr. LeBlanc's twenty-six years of experience include assignments in the oil and gas subsidiaries of Celeron Corporation and Goodyear Tire and Rubber. Prior to his industry experience, Mr. LeBlanc was with a national accounting firm, he is a certified public accountant, a chartered financial analyst, and received a Bachelor of Science degree from University of Southwestern Louisiana.

Herbert A. Newhouse, Senior Vice President - Gulf Coast, joined the Company in 1998. Prior to joining Range, Mr. Newhouse served as Executive Vice President of Domain Energy Corporation. He was a former 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 oil and gas exploration and production. Mr. Newhouse received a Bachelor of Science degree in Chemical Engineering from Ohio State University.

Chad L. Stephens, Senior Vice President - Southwest, joined the Company in 1990. Previously, Mr. Stephens was with Duer Wagner & Co., an independent oil and gas producer, since 1988. Prior thereto, 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 Degree 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 had been with Snyder Oil Corporation, now part of Devon Energy Corporation, since 1977, where he served as a senior vice president. Before joining Snyder, Mr. Waller was employed by Arthur Andersen. Mr. Waller received a Bachelor of Arts degree from Harding University.

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

Audit Committee. The Audit Committee reviews the professional services provided by independent public accountants and the independence of such accountants from management. 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. Aikman, Dub, Eales and Lynch 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 nominations of candidates for officer positions. The members of the Compensation Committee are Messrs. Aikman, Finkelson, Lynch and McCormick.

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

Executive Committee. The Executive Committee reviews and authorizes actions required in the management of the business and affairs of Range, which would otherwise be determined by the Board, where it is not practicable to convene the full Board. One of the principal responsibilities of the Executive Committee will be to review and approve smaller acquisitions. The members of the Executive Committee are Messrs. Edelman, Finkelson and Pinkerton.

Nominating Committee. The Nominating Committee develops and reviews background information for 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, Lynch and McCormick.

ITEM 11. COMPENSATION OF EXECUTIVE OFFICERS AND DIRECTORS

Information with respect to officers' compensation is incorporated herein by reference to the Company's 2002 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 2002 Proxy Statement.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENTS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) 1. and 2. Financial Statements and Financial Statement Schedules

The items listed in the accompanying index to financial statements are filed as part of this Annual Report on Form 10-K.

3. Exhibits.

The items listed on the accompanying index to exhibits are filed as part of this Annual Report on Form 10-K.

(b) Reports on Form 8-K.

None.

(c) Exhibits required by Item 601 of Regulation S-K

Exhibits required to be filed pursuant to Item 601 of Regulation S-K are contained in Exhibits listed in response to Item 14 (a)3, and are incorporated herein by reference.

(d) Financial Statement Schedules Required by Regulation S-X.

The items listed in the accompanying index to financial statements are filed as part of this Annual Report on Form 10-K.

SIGNATURES

PURSUANT TO THE REQUIREMENTS OF SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934, THE COMPANY HAS DULY CAUSED THIS REPORT TO BE SIGNED ON ITS BEHALF BY THE UNDERSIGNED, THEREUNTO DULY AUTHORIZED.

Dated: October 24, 2002

RANGE RESOURCES CORPORATION

By: /s/ John H. Pinkerton

John H. Pinkerton
President

I, John H. Pinkerton, certify that:

1. I have reviewed this annual report on Form 10-K/A 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.

Date: October 24, 2002

/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/A 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.

Date: October 24, 2002

/s/ Eddie M. LeBlanc

Eddie M. LeBlanc, Chief Financial Officer

GLOSSARY

The terms defined in this glossary are used throughout this Form 10-K/A.

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.

Credit Facility. The Range Resources Corporation $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 either oil or natural gas in sufficient quantities to justify completion as an oil or gas well.

Exploratory well. A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, 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 high value transactions.

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

mcf. One thousand cubic feet.

mcf/d. One thousand cubic feet per day.

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

Merger. The acquisition via merger of Domain Energy Corporation by Lomak Petroleum, Inc. in August 1998. Simultaneously, Lomak's name was changed to Range Resources Corporation.

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

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

Mmcf. One million cubic feet.

Mmcfe. One million cubic feet of natural gas equivalents.

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

Net oil and gas sales. Oil and natural gas sales less oil and natural gas production expenses.

Oil and gas royalty trust. An arrangement whereby typically, the creating company conveys a net profits interest in certain of its oil and gas properties to the newly created trust and then distributes ownership units in the trust to its unitholders. The function of the trust is to serve as agent to distribute income from the net profits interest to its unitholders.

Present Value. 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 an existing wellbore in another formation from that in which the well has previously been completed.

Reserve life index. The presentation of proved reserves defined in number of years of annual production.

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

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 extend to the economic life of the property and is of shorter duration than the underlying working interest. The term overriding royalties in which the Company participates through its Independent Producer Finance subsidiary typically extend until amounts financed and a designated rate of return have been achieved. At such point in time, 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 14[A], [D])

Exhibits

All other schedules have been omitted since the required 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 footnotes.

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, 2000 and 2001, 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, 2001. 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 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 provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Range Resources Corporation as of December 31, 2000 and 2001, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company has restated their consolidated balance sheets as of December 31, 2000 and 2001, 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, 2001, which were audited by other auditors who have ceased operations.

As discussed in Note 3 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
September 20, 2002

RANGE RESOURCES CORPORATION

CONSOLIDATED BALANCE SHEETS
(IN THOUSANDS, EXCEPT PER SHARE DATA)

	DECEMBER 31, 2000 RESTATED	DECEMBER 31, 2001 RESTATED
ASSETS		
Current assets		
Cash and equivalents	$ 2,612	$ 3,380
Accounts receivable	33,278	25,295
IPF receivables (Note 5)	20,800	7,000
Unrealized derivative hedging gain (Note 8)	--	37,165
Inventory and other	6,196	4,895
	62,886	77,735
IPF receivables, net (Note 5)	28,128	34,402
Unrealized derivative hedging gain (Note 8)	--	14,936
Oil and gas properties, successful efforts method (Note 18)	997,049	1,047,629
Accumulated depletion	(443,876)	(514,272)
	553,173	533,357
Transportation and field assets (Note 3)	33,593	31,288
Accumulated depreciation	(12,339)	(13,108)
	21,254	18,180
Other (Note 3)	6,385	3,852
	$ 671,826	$ 682,462
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 27,823	$ 27,202
Accrued liabilities	16,888	15,036
Accrued interest	7,774	5,244
Unrealized derivative hedging loss (Note 8)	736	397
	53,221	47,879
Senior debt (Note 7)	89,900	95,000
Non-recourse debt (Note 7)	113,009	98,801
Subordinated notes (Note 7)	162,550	108,690
Trust preferred - mandatorily redeemable securities of subsidiary (Note 7)	92,640	89,740
Commitments and contingencies (Note 9)		
Deferred taxes (Note 14)	--	4,496
Unrealized derivative hedging loss (Note 8)	562	2,235
Stockholders' equity (Notes 10 and 11)		
Preferred stock, $1 par, 10,000,000 shares authorized, $2.03 convertible preferred, 219,935 and -0- issued and outstanding, respectively (liquidation preference $5,498,375 and $-0-, respectively)	220	--
Common stock, $.01 par, 100,000,000 shares authorized, 49,187,682 and 52,643,275 issued and outstanding, respectively	492	526
Capital in excess of par value	364,925	378,426
Stock held by employee benefit trust, 851,140 and 1,038,242 shares, respectively (Note 12)	(3,496)	(4,890)
Retained earnings (deficit)	(201,478)	(183,825)
Deferred compensation expense	(80)	(139)
Other comprehensive income (loss) (Note 3)	(639)	45,523
	159,944	235,621
	$ 671,826	$ 682,462

SEE ACCOMPANYING NOTES.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(IN THOUSANDS, EXCEPT PER SHARE DATA)

	YEAR ENDED DECEMBER 31,		
	1999	2000	2001
	RESTATED	RESTATED	RESTATED
Revenues			
Oil and gas sales	$ 145,492	$ 173,082	$ 208,854
Transportation and processing	7,770	5,306	3,435
IPF	8,513	7,162	6,646
Interest and other	343	(722)	490
Gain on formation of Great Lakes (Note 20)	30,929	--	--
	193,047	184,828	219,425
Expenses			
Direct operating	43,074	40,552	43,430
IPF	6,389	1,974	3,761
Exploration	2,409	3,187	5,879
General and administrative	8,793	14,953	12,212
Interest expense and dividends on trust preferred	47,085	39,953	32,179
Depletion, depreciation and amortization	80,598	66,968	77,573
Provision for impairment (Note 3)	29,901	--	31,085
	218,249	167,587	206,119
Pretax income (loss)	(25,202)	17,241	13,306
Income taxes (benefit) (Note 14)			
Current	770	(1,574)	(406)
Deferred	--	--	--
	770	(1,574)	(406)
Income (loss) before extraordinary item	(25,972)	18,815	13,712
Extraordinary item			
Gain on retirement of debt securities, net (Note 21)	2,430	17,763	3,951
Net income (loss)	$ (23,542)	$ 36,578	$ 17,663
Comprehensive income (loss) (Note 3)	$ (23,645)	$ 35,750	$ 63,825
Earnings (loss) per share basic and diluted (Note 16)			
Before extraordinary item			
Basic	$ (0.78)	$ 0.55	$ 0.28
Diluted	$ (0.78)	$ 0.54	$ 0.28
After extraordinary item			
Basic	$ (0.71)	$ 0.97	$ 0.36
Diluted	$ (0.71)	$ 0.96	$ 0.36

SEE ACCOMPANYING NOTES.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
(IN THOUSANDS)

	YEAR ENDED DECEMBER 31,		
	1999	2000	2001
	RESTATED	RESTATED	RESTATED
CASH FLOW FROM OPERATIONS:			
Net income (loss)	$ (23,542)	$ 36,578	$ 17,663
Adjustments to reconcile net income (loss) to net cash provided by operations:			
Depletion, depreciation and amortization	80,598	66,968	77,573
Write-down of marketable securities	--	--	1,715
Unrealized hedging gains reclassification	--	--	(1,019)
Provision for impairment	29,901	--	31,085
Allowance for bad debts	--	615	2,040
Allowance for IPF receivables	1,224	(2,891)	122
Amortization of deferred offering costs	1,333	2,020	1,961
Non-cash compensation expense	2,217	4,366	(295)
Gain on retirement of securities	(2,430)	(17,978)	(4,004)
(Gain) loss on sale of assets	(30,399)	1,116	(689)
Changes in working capital:			
Accounts receivable	7,978	(6,568)	5,540
Inventory and other	(1,589)	(522)	226
Accounts payable	(4,062)	(5,627)	548
Accrued liabilities and other	(11,042)	(3,198)	(2,868)
Net cash provided by operations	50,187	74,879	129,598
CASH FLOW FROM INVESTING:			
Investment in Great Lakes	98,715	--	--
Oil and gas properties	(25,093)	(47,474)	(87,034)
Field service assets	(656)	(2,263)	(2,331)
IPF investments	(5,362)	(6,985)	(11,629)
IPF repayments	13,160	24,764	19,034
Proceeds from sales of assets	17,476	25,944	3,771
Net cash provided by (used in) investing	98,240	(6,014)	(78,189)
CASH FLOW FROM FINANCING:			
Repayments of indebtedness	(145,129)	(79,611)	(52,046)
Preferred dividends	(2,334)	(1,444)	(10)
Common dividends	(1,107)	--	--
Issuance of common stock	2,152	1,798	1,488
Repurchase of common stock	(26)	--	--
Repurchase of preferred stock	--	--	(73)
Net cash used in financing	(146,444)	(79,257)	(50,641)
Change in cash	1,983	(10,392)	768
Cash and equivalents, beginning of year	11,021	13,004	2,612
Cash and equivalents, end of year	$ 13,004	$ 2,612	$ 3,380

SEE ACCOMPANYING NOTES.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(IN THOUSANDS)

	PREFERRED STOCK		COMMON STOCK				STOCK HELD			
	SHARES	PAR VALUE	SHARES	PAR VALUE	DEFERRED COMPENSATION EXPENSE	CAPITAL IN EXCESS OF PAR VALUE	BY EMPLOYEE BENEFIT TRUST	RETAINED EARNINGS (DEFICIT)	OTHER COMPREHENSIVE INCOME	TOTAL
BALANCE DECEMBER 31, 1998 (Restated)	1,150	$ 1,150	35,933	$ 359	$ --	$ 335,232	$ (1,845)	$(209,519)	$ 292	$ 125,669
Preferred dividends	--	--	--	--	--	--	--	(2,334)	--	(2,334)
Common dividends	--	--	--	--	--	--	--	(1,107)	--	(1,107)
Issuance of common	--	--	1,270	13	(69)	2,596	(1,241)	--	--	1,299
Conversion of securities	--	--	699	7	--	3,349	--	--	--	3,356
Other comprehensive income	--	--	--	--	--	--	--	--	(103)	(103)
Net income	--	--	--	--	--	--	--	(23,542)	--	(23,542)
BALANCE DECEMBER 31, 1999 (Restated)	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 (Restated)	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

SEE ACCOMPANYING NOTES.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) ORGANIZATION AND NATURE OF BUSINESS

Range Resources Corporation ("Range") 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 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"). The Company's financial statements for the three years ended 2001 have been restated (See Note 2).

(2) RESTATEMENT

In July 2002, the Company selected KPMG LLP as its new independent auditor. The Company also chose to have KPMG 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, insure the Company's ongoing access to the capital markets and to avoid any possible impediment to future transactions. As part of the selection process, KPMG performed its normal client acceptance procedures and advised the Company that it believed a different accounting principle should have been used to determine the gain recognized in September 1999 on the formation of the Great Lakes joint venture. Specifically, the gain recognized in September 1999 should be reduced from $39.8 to $30.9 million and income in subsequent periods should increase as a result of lower depletion expense.

As a result of the actual reaudit, a series of additional issues came to light which required restatement of the Company's previously reported operating results and financial condition. These issues and their impact on pretax income is outlined below.

In 1998, the Company acquired Domain Energy. In recording the transaction, the purchase price was not appropriately allocated to the individual oil and gas properties, causing a subsequent purchase price adjustment to be miscalculated. As a result of correcting for this matter, impairments recognized at year-end 2001 were reduced. In addition, properties in Appalachia and Michigan, that had been combined into accounting pools for the purpose of calculating depletion, were subdivided into smaller pools, as the combined Michigan properties lacked a common geological formation, and the depreciation rates historically applied on non-oil and gas assets were reduced. As a result of these changes, pretax income decreased $7.1 million in 1999, increased $4.8 million in 2000 and increased $7.6 million in 2001.

The Company maintains a deferred compensation plan (the "Plan"), under which eligible employees can defer all or a portion of their cash compensation and invest those amounts in a variety of investment options (including Company common stock) which are placed in a rabbi trust (the "Trust"). Eligible employees can also place common stock awards in the Trust. Pursuant to a consensus of the Emerging Issues Task Force, assets and liabilities of the Trust must be consolidated on the Company's balance sheet. While the Trust's assets and liabilities are of identical value, Company common stock held in the Trust is treated as if it were treasury stock (it is deducted from outstanding shares as shares held by an employee benefit plan). Furthermore, because the Plan allows participants to diversify their investments, the liability to Plan participants must be revalued on the balance sheet each accounting period at the then-quoted market prices of the Company's common stock held by the Trust and increases or decreases between accounting periods reflected on the statement of operations as increases or decreases in compensation expense. Historically, the Company did not consolidate the Trust in its consolidated financial statements nor added or subtracted changes in the market value of the Company's common stock held by the Trust on its statement of operations. However, all material information about the Plan has historically been disclosed in footnotes to the financial statements and in proxy statements. In addition, the Company offers designated employees the ability to purchase shares at a discount under a shareholder-approved Stock Purchase Plan or to receive bonuses or a portion of their base pay in restricted common stock issued at a discount from quoted market prices. Previously, such shares had always been accounted for based on the Company's estimate of the fair value of the stock granted or purchased. In the restated financial statements, stock purchased through the Plan or granted to employees was expensed based on the quoted market value without regard to the Company's estimate of fair value. The difference between previously reported values and market value will be included as additional compensation expense on the restated statements of operations. As a result of these changes, pretax income decreased $561,000 in 1999, decreased $3.8 million in 2000 and increased $1.7 million in 2001.

At June 30, 2002, the Company corrected a series of unreconciled balance sheet accounts that had a net minimal statement of operations impact. These balance sheet general ledger accounts were not supported by the underlying subsidiary ledger detail when the Company's accounting department moved from Ohio to Fort Worth. In the restatement, these corrections were reflected in the periods in which they applied, rather than in the second quarter of 2002 when the Company originally corrected for the differences. As a result, pretax income for periods prior to 1999 increased by $1.9 million, increased by $627,000 in 1999, decreased $2.9 million in 2000 increased by $190,000 in 2001.

Finally, certain of GLEP's interest rate swaps had early cancellation provisions but had been accounted for as cash flow hedges. Upon further review, the swaps did not meet the documentation and effectiveness provisions of SFAS 133, requiring changes in fair value to be reported as interest expense on the restated financial statements as opposed to changes in Other Comprehensive Income. As a result, pretax income decreased $1.4 million in 2001 and will increase by a corresponding amount in future periods. Additionally, the ineffective portion of certain commodity hedges increased income $71,000 in 2001.

In total, all of the current changes (including the previously announced change in the gain on the Great Lakes' transaction) increased net loss by $15.7 million in 1999, decreased net income by $1.4 million in 2000 and increased net income by $8.7 million in 2001.

The following shows the effect of the restatement (in thousands, except per share amounts):

1999	PREVIOUSLY REPORTED	RESTATED
Gain on formation of Great Lakes	$ 39,810	$ 30,929
General and administrative	8,028	8,793
Depletion, depreciation and amortization	76,447	80,598
Provision for impairment	27,118	29,901
Pretax loss	(8,622)	(25,202)
Income taxes	1,601	770
Loss before extraordinary item	(10,223)	(25,972)
Net loss	(7,793)	(23,542)
Loss per share before extraordinary gain		
Basic	(0.34)	(0.78)
Diluted	(0.34)	(0.78)
Loss per share after extraordinary gain		
Basic	(0.27)	(0.71)
Diluted	(0.27)	(0.71)
Cash and equivalents	12,937	13,004
Accounts receivable	21,646	25,759
Inventory and other	6,196	6,530
Oil and gas properties	978,919	959,843
Accumulated depletion	(383,622)	(389,200)
Accounts payable	23,925	26,957
Accrued liabilities	16,074	16,835
Stock held by employee benefit trust	--	(3,086)
Capital in excess of par value	340,279	341,177
Other comprehensive income (loss)	(7)	189
Retained earnings (deficit)	(214,630)	(236,502)
Deferred compensation expense	--	(69)
Stockholders' equity	127,171	103,307

2000	PREVIOUSLY REPORTED	RESTATED
Direct operating	$ 38,525	$ 40,552
General and administrative	10,323	14,953
Depletion, depreciation and amortization	72,242	66,968
Pretax income	18,624	17,241
Income before extraordinary item	20,198	18,815
Net income	37,961	36,578
Earnings per share before extraordinary gain		
Basic	0.57	0.55
Diluted	0.57	0.54
Earnings per share after extraordinary gain		
Basic	0.99	0.97
Diluted	0.99	0.96
Cash and equivalents	2,485	2,612
Accounts receivable	33,221	33,278
Inventory and other	5,580	6,196
Oil and gas properties	1,014,939	997,049
Accumulated depletion	(443,097)	(443,876)
Other	5,855	6,385
Accounts payable	26,744	27,823
Accrued liabilities	11,341	16,888
Unrealized derivative hedging loss - current	--	736
Unrealized derivative hedging loss - noncurrent	--	562
Stock held by employee benefit trust	--	(3,496)
Capital in excess of par value	363,625	364,925
Other comprehensive loss	(907)	(639)
Retained earnings (deficit)	(178,223)	(201,478)
Deferred compensation expense	--	(80)
Stockholders' equity	185,207	159,944
Cash flows -		
Net cash provided by operations	74,108	74,879
Net cash used in investing	(5,303)	(6,014)

2001	PREVIOUSLY REPORTED	RESTATED
Oil and gas sales	$ 209,537	$ 208,854
Direct operating	44,504	43,430
General and administrative	13,511	12,212
Interest	30,689	32,179
Depletion, depreciation and amortization	77,825	77,573
Provision for impairment	38,945	31,085
Pretax income	4,994	13,306
Current income taxes	(51)	(406)
Income before extraordinary item	5,045	13,712
Net income	8,996	17,663
Earnings per share before extraordinary gain		
Basic	0.11	0.28
Diluted	0.11	0.28
Earnings per share after extraordinary gain		
Basic	0.19	0.36
Diluted	0.19	0.36
Cash and equivalents	3,253	3,380
Accounts receivable	27,495	25,295
Inventory and other	4,084	4,895
Unrealized derivative hedging gain - current	36,768	37,165
Unrealized derivative hedging gain - noncurrent	12,701	14,936
Oil and gas properties	1,057,881	1,047,629
Accumulated depletion	(512,786)	(514,272)
Accumulated depreciation	(13,576)	(13,108)
Other	3,055	3,852
Accounts payable	26,944	27,202
Accrued liabilities	9,947	15,036
Accrued interest	7,105	5,244
Unrealized derivative hedging loss - current	--	397
Unrealized derivative hedging loss - noncurrent	--	2,235
Deferred taxes	9,651	4,496
Stock held by employee benefit trust	--	(4,890)
Capital in excess of par value	376,357	378,426
Retained earnings (deficit)	(169,237)	(183,825)
Other comprehensive income	38,041	45,523
Deferred compensation expense	--	(139)
Stockholders' equity	245,687	235,621
Cash flows --		
Net cash provided by operations	130,309	129,598
Net cash used in investing	(78,900)	(78,189)

(3) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

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

REVENUE RECOGNITION

The Company recognizes revenues from the sale of products and services in the period delivered. Revenues at IPF are recognized as received. The Company's receivables are concentrated in the oil and gas industry. The Company had allowances for doubtful accounts relating to its exploration and production business of $2.3 million and $2.9 million at December 31, 2000 and 2001, respectively. At the same dates, IPF had valuation allowances of $15.3 million and $17.3 million, respectively. A decrease in oil prices could cause an increase in IPF's valuation allowances and a corresponding decrease in income.

MARKETABLE SECURITIES

The Company has adopted Statement of Financial Accounting Standards ("SFAS") No. 115, "Accounting for Certain Investments." Pursuant to SFAS 115, the Company's 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. 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. During 2001, 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 were recorded as reductions to Interest and other revenues.

INDEPENDENT PRODUCER FINANCE

IPF acquires dollar denominated royalties in oil and gas properties from smaller producers. These royalties are accounted for as receivables because the investment is recovered from an agreed-upon share of revenues until a specified rate of return is received. The portion of payments received relating to the return is recognized as income; remaining receipts are considered a return of capital and reduce receivables. Receivables classified as current represent the return of capital expected to be received within twelve 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. At December 31, 2001, the valuation allowance totaled $17.3 million. 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 which 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 the first nine months of 2001. However, because of lower prices, IPF increased its reserve allowance by $2.0 million in the fourth quarter of 2001. During 2000 and 2001, IPF expenses were comprised of $1.5 million and $1.8 million of general and administrative costs and $3.4 million and $1.8 million of interest, respectively. In 2000, IPF recorded a $2.9 million favorable adjustment to their valuation allowance. The valuation allowance at December 31, 2000 and 2001 was $13.7 million and $17.3 million, respectively.

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. Costs resulting in discoveries and development costs are capitalized. Geological and geophysical costs, delay rentals and costs to drill unsuccessful exploratory wells are expensed. Depletion is provided on the unit-of-production method. Oil is converted to mcfe at the rate of six mcf per barrel. The depletion, depreciation and amortization ("DD&A") rates (as restated) were $1.21, $1.21 and $1.39 per mcfe in 1999, 2000 and 2001, respectively. Unproved properties had a net book value of $61.8 million, $49.5 million and $25.7 million at December 31, 1999, 2000 and 2001, respectively.

The Company has adopted SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets", which establishes accounting standards for the impairment of long-lived assets, certain identifiable intangibles and goodwill. SFAS No. 121 requires a review for impairment whenever circumstances indicate that the carrying amount of an asset may not be recoverable.

Acreage is assessed periodically to determine whether there has been a decline in value. If such decline is indicated, a loss is recognized. The Company compares the carrying value of its acreage to their estimated fair value, using information such as an assessment of value that could be recovered from sale, farm-out or exploitation, a geological assessment of the acreage, other acreage purchases in the area, timing of the associated drilling program or the property's unique nature. During 1999 and 2001, the Company recorded $6.1 million and $5.1 million, respectively, for impairment of acreage. The amount of impairment was calculated by determining fair value using management's best estimate of the value of these properties.

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

Year Ended December 31,	Property	Reason for Impairment	Impairment Amount
1999	Offshore Other	Reserve revisions and lower oil and gas prices	$ 6,100
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

Impairment is recognized only if the carrying amount of a property is greater than its expected undiscounted future cash flows. Impairment on proved properties is generally based on the difference between the carrying amount of the assets and the present value of the estimated future cash flows from proved reserves.

The following are the proved property values impaired, due to declines in gas prices, in 1999 and 2001 based on the analysis of estimated future cash flows (in thousands):

Year Ended December 31,	Property	Reason for Impairment	Impairment Amount Restated
1999	Oceana (GLEP)	Decline in gas price	$ 1,566
	Permian Other	Decline in gas price	1,217
			$ 2,783
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 (GLEP)	Decline in gas price	99
	Total		$ 25,944

TRANSPORTATION, PROCESSING AND FIELD ASSETS

The Company's gas gathering systems are 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 four to fifteen years. The Company sold its only remaining gas processing facility in June 2000. In connection with the sale of the gas processing plant, an impairment loss of $21.0 million was recorded in 1999. See Note 6.

The Company receives fees 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 three to seven years. Buildings are depreciated over ten years.

SECURITY ISSUANCE COSTS

Expenses associated with the issuance of 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. When a security is retired prior to maturity, related unamortized costs are expensed. At December 31, 2001, such deferred financing costs totaled $3.0 million.

GAS IMBALANCES

The Company uses the sales method to account for gas imbalances, recognizing revenue based on cash received rather than gas produced. At December 31, 2000 and December 31, 2001, gas imbalance liabilities of $318,000 and $114,000 were included in Accrued liabilities, respectively.

COMPREHENSIVE INCOME

The Company follows SFAS No. 130, "Reporting Comprehensive Income," defined as changes in Stockholders' equity from nonowner sources. The following is a calculation of comprehensive income for each of the three years ended December 31, 2001 (in thousands).

	Year Ended December 31,		
	1999	2000	2001
	Restated	Restated	Restated
Net income (loss)	$ (23,542)	$ 36,578	$ 17,663
Cumulative effect of change in accounting principle	--	--	(72,100)
Change in unrealized hedging gain/(losses), net	--	--	116,659
Unrealized loss from available-for-sale securities	(103)	(828)	931
Defaulted hedge contracts, net*	--	--	672
Comprehensive income (loss)	$ (23,645)	$ 35,750	$ 63,825

* Includes $1.0 million gain related to amounts due from Enron. 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 Comprehensive income.

USE OF ESTIMATES

The preparation of financial statements in conformity with generally accepted accounting principles 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 reserve estimates, analysis of impairment of oil and gas properties, reserve requirement for IPF receivables and fair value estimates of derivatives.

RECENT ACCOUNTING PRONOUNCEMENTS

In July 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) 141 "Business Combinations" and 142 "Goodwill". SFAS 141 required that business combinations initiated after June 30, 2001 be accounted for as purchases and SFAS 142 required that goodwill be reviewed for impairment instead of amortized. To date, these statements have had no impact on the Company.

In April 2002, the FASB issued SFAS 145 relating to the extinguishment of debt. The Company has not yet determined the effects of this Statement but it appears gains or losses on debt extinguishment will no longer be treated as extraordinary. The Company intends to adopt SFAS 145 on January 1, 2003.

In June 2001, FASB issued SFAS 143 "Asset Retirement Obligations" 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 and the related transition adjustment will be reported as a cumulative effect of a change in accounting principle. The Company cannot yet reasonably estimate the effect of the adoption on either its financial position or results of operations.

In August 2001, the FASB issued SFAS 144, "Impairment or Disposal of Long-Lived Assets" establishing a single accounting model for long-lived assets to be disposed of by sale and providing additional guidance for assets to be held and used and assets to be disposed of other than by sale. The Company adopted the Statement on January 1, 2002.

Beginning in 2001, SFAS 133 "Derivatives" required that derivatives be recorded on the balance sheet as assets or liabilities at fair value and that changes in fair value should be recognized immediately in earnings unless the derivative qualified as a hedge of future cash flows. For derivatives qualifying as hedges of future cash flows, the effective portion of any changes in fair value is recognized in a component of stockholders' equity called OCI and then reclassified to earnings when the underlying transaction is consummated. Any ineffective portion of such hedges is recognized in earnings as it occurs. On adopting SFAS 133 in January 2001, the Company recorded $72.1 million of unrealized pre-tax hedging loss on its balance sheet and an offsetting deficit in OCI. Due to the decline in oil and gas prices between January 1, 2001 and December 31, 2001, this loss had become a net $52.1 million unrealized pre-tax gain by year-end. SFAS 133 tends to increase earnings volatility in independent oil companies.

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 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 regularly enters into contracts to reduce the effect of fluctuations in oil and gas prices. These contracts generally qualify as cash flow hedges. 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 either in current period income or in OCI. The Company also enters into swap agreements to reduce the risk of changing interest rates. These agreements qualify as fair value hedges and related income or expense is recorded as an adjustment to interest expense in the period covered.

Interest and other revenues in the Consolidated Statements of Operations was increased for ineffective hedging gains of $2.3 million in the year ended December 31, 2001. Unrealized hedging gains and losses (excluding Enron), including interest rate swaps, of $49.5 million and restated OCI of $45.5 million, net of taxes, were recorded on the balance sheet at December 31, 2001. See Note 8.

RECLASSIFICATIONS

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

(4) ACQUISITIONS

All acquisitions have been 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 other properties for consideration of $846,000, $4.7 million and $9.5 million during the years ended December 31, 1999, 2000 and 2001, respectively.

(5) IPF RECEIVABLES

At December 31, 2000 and 2001, IPF had net receivables of $48.9 million and $41.4 million, respectively. The receivables represent overriding royalty interests payable from an agreed-upon share of revenues until a specified return is achieved. The royalties constitute property interests that serve as security for the receivables. Due to favorable oil and gas prices during the last nine months of 2000 and the first half of 2001, some of these receivables began to generate a greater proportion of their contractual return. In the first nine months of 2001, the book value of the affected receivables was increased and approximately $1.8 million was recorded as a reduction to IPF expense. However, because of lower prices, IPF increased its reserve allowance by $2.0 million in the fourth quarter of 2001. The Company estimates that $7.0 million of receivables at December 31, 2001 will be repaid in the next twelve months and has classified them as current. IPF receivables reflected valuation allowances of $13.7 million and $17.3 million at December 31, 2000 and 2001, respectively. A further decline in the price of oil could cause an increase in IPF's valuation allowances and a corresponding decrease in income.

(6) 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
	Restated
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.

(7) INDEBTEDNESS

The Company had the following debt and Trust preferred outstanding as of the dates shown. Interest rates, excluding the impact of interest rate swaps, at December 31, 2001 are shown parenthetically (in thousands):

	December 31, 2000	December 31, 2001
SENIOR DEBT		
Credit Facility (3.9%)	$ 89,900	$ 95,000
NON-RECOURSE DEBT		
Great Lakes credit facility (3.9%)	84,509	75,001
IPF credit facility (4.4%)	28,500	23,800
	113,009	98,801
SUBORDINATED DEBT		
8.75% Senior Subordinated Notes due 2007	125,000	79,115
6% Convertible Subordinated Debentures due 2007	37,550	29,575
	162,550	108,690
TOTAL DEBT	365,459	302,491
TRUST PREFERRED - MANDITORILY REDEEMABLE SECURITIES OF SUBSIDIARY	92,640	89,740
TOTAL	$458,099	$392,231

From January 1, 2002 to March 1, 2002, the Company exchanged an additional $0.9 million face amount of the 8.75% Notes. Interest paid in cash during the years ended December 31, 2000 and 2001 totaled $42.2 million and $31.2 million, respectively. No interest expense was capitalized during 1999, 2000 or 2001.

SENIOR DEBT

The Company maintains a $225 million secured revolving bank facility (the "Parent Facility"). The Parent Facility provides for a borrowing base which is subject to semi-annual redeterminations in April and October. On March 1, 2002, the borrowing base on the Parent Facility was $120.0 million of which $16.5 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. Interest is payable the earlier of quarterly or as LIBOR notes mature. The loan matures in February 2003. 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, 2001, the commitment fee was 0.50% and the interest rate margin was 0.75%. The weighted average interest rates on the Parent Facility was 8.8% and 6.4% for the years ended December 31, 2000 and 2001, respectively. As of March 1, 2002, the interest rate was 3.3%.

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. On March 1, 2002, the borrowing base was $200.0 million of which $54.0 million was available. Interest is payable the earlier of quarterly or as LIBOR notes mature. The loan matures in September 2003. 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, 2001, the commitment fee was 0.50% and the interest rate margin was 0.625%. The weighted average interest rates on these borrowings, excluding interest rate hedges, were 8.5% and 6.4% for the years ended December 31, 2000 and 2001, respectively. After hedging, the rate was 8.6% and 9.4% for the twelve months ended December 30, 2000 and 2001, respectively. At March 1, 2002, the interest rate was 3.6%, excluding interest rate hedges and 6.5% including interest rate hedges.

IPF has a $100.0 million secured revolving credit facility (the "IPF Facility"). The IPF Facility is non-recourse to Range and matures in January 2004. The borrowing base under the IPF Facility is subject to semi-annual redeterminations in April and October. On March 1, 2002, the borrowing base on the IPF Facility was $35.0 million of which $11.7 million was available. The IPF Facility bears interest at LIBOR plus 1.75% to 2.25% depending on outstandings. Interest expense in the IPF Facility is included in IPF expenses in the Consolidated Statements of Income and amounted to $3.4 million and $1.8 million for the years ended December 31, 2000 and 2001, respectively. A commitment fee is paid quarterly on the undrawn balance at an annual rate of 0.375% to 0.50%. The weighted average interest rate on these borrowings was 8.5% and 6.4% for the years ended December 31, 2000 and 2001, respectively. As of March 1, 2002, the interest rate was 4.3%.

SUBORDINATED NOTES

The 8.75% Senior Subordinated Notes due 2007 (the "8.75% Notes") become redeemable beginning on January 15, 2002, in whole or in part, 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 all senior debt (as defined). 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 twelve months ended December 31, 2001, the Company repurchased $42.5 million face amount of the 8.75% Notes at a discount. The Company also exchanged $3.4 million of the 8.75% Notes for common stock. Exchanges are not reflected on the cash flow statement. The cash flow reflects a $41.2 million Repayment of debt relating to these repurchases. The gain on these repurchases is included as a Gain on retirement of securities on the Consolidated Statements of Operations. The repurchased notes are held in treasury and may be reissued. Subsequent to December 31, 2001, the Company exchanged for common stock an additional $0.9 million face amount of the 8.75% Notes. As of March 1, 2002, $78.2 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 103.5% 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 (as defined), including the 8.75% Notes. During 2000 and 2001, $13.8 million and $5.7 million of 6% Debentures were retired at a discount in exchange for 2.5 million and 0.7 million shares of common stock, respectively. In addition, $2.3 million were repurchased in 2001. Exchanges are not reflected on the cash flow statement. Extraordinary gains of $4.3 million and $1.9 million were recorded in 2000 and 2001, respectively. As of March 1, 2002, $29.6 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 5-3/4% 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 5-3/4% 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 103.450% 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, at its sole discretion, to suspend payment of all distributions on the Trust Preferred for five years without triggering a default. The accounts of the Trust are included in Range's consolidated financial statements after eliminations. Distributions 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 twelve 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. The exchange transactions are not reflected on the cash flow statement because no cash was involved. As of March 1, 2002, $89.7 million of the Trust Preferred remained outstanding.

The debt agreements contain various covenants relating to net worth, working capital maintenance, restrictions on dividends and financial ratio. If certain ratio requirements are not met, payments of interest on the Trust Preferred would be restricted. The Parent Facility prohibits the payment of dividends on common stock. The Company was in compliance with all such covenants at December 31, 2001. Under the most restrictive covenant, $3.0 million of dividends or other restricted payments could be paid at December 31, 2001. Under the Parent Facility, common dividends are prohibited and dividends may not be paid on the Trust Preferred unless certain ratio requirements are met.

Following is the principal maturity schedule for the long-term debt outstanding as of December 31, 2001 (in thousands):

Year ending December 31:	
2002	$ --
2003	170,001
2004	23,800
2005	--
2006	--
2007	108,690
Thereafter	89,740
	$392,231

(8) FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

The Company's financial instruments include cash and equivalents, accounts receivable, accounts payable, debt obligations and commodity and interest rate derivatives. The book value of cash and equivalents and accounts receivable and payable are considered to be representative of fair value because of their short maturity. The book values of borrowings under the Parent Facility, the Great Lakes Facility, and IPF Facility are believed to approximate fair value because of their floating rate structure.

A portion of the Company's 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, 2000		December 31, 2001	
	Book Value	Fair Value	Book Value	Fair Value
	Restated	Restated	Restated	Restated
Assets				
Cash and equivalents	$ 2,612	$ 2,612	$ 3,380	$ 3,380
Marketable securities	2,861	2,861	2,323	2,323
Commodity swaps*	-	-	52,100	52,100
Total	5,473	5,473	57,803	57,803
Liabilities				
Commodity swaps	-	(72,090)	-	-
Interest rate swaps	-	(879)	(2,631)	(2,631)
Long-term debt	(365,459)	(348,257)	(302,491)	(292,028)
Trust Preferred	(92,640)	(53,268)	(89,740)	(50,254)
Total	(458,099)	(474,494)	(394,862)	(344,913)
Net financial instruments	$ (452,626)	$ (469,021)	$ (337,059)	$ (287,110)

* Excluding hedge agreements with Enron (see below)

At December 31, 2001, the Company had open hedging contracts (excluding contracts with Enron) covering 47.3 Bcf of gas at prices averaging $4.02 per mcf and 700,000 barrels of oil at prices averaging $25.97 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 gain of $52.1 million at December 31, 2001. 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. Net pre-tax losses incurred relating to these derivatives for the years ended December 31, 1999, 2000 and 2001 were $10.6 million, $43.2 million, and $6.2 million, respectively. 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.

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. Amounts due from Enron are not included in the open hedges described in the previous paragraph. Based on accounting requirements, the Company has 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 will be included in income in the first quarter of 2002. The last of the Enron contracts will expire as of March 2002.

The following schedule shows the effect of the Company's hedge position for the four quarters ended December 31, 2001 and the projected impact of open contracts (excluding contracts with Enron) as of that date.

Quarter Ended	Hedging Gain (Loss) Exposure
Closed contracts:	
March 31, 2001	$ (23,440)
June 30, 2001	(5,250)
September 30, 2001	8,450
December 31, 2001	14,047
Total	$ (6,193)
Open Contracts:	
March 31, 2002	11,010
June 30, 2002	9,809
September 30, 2002	8,613
December 31, 2002	7,732
March 31, 2003	3,233
June 30, 2003	2,897
September 30, 2003	2,828
December 31, 2003	2,628
March 31, 2004	619
June 30, 2004	668
September 30, 2004	657
December 31, 2004	701
March 31, 2005	167
June 30, 2005	165
September 30, 2005	187
December 30, 2005	186
Total	$ 52,100

Interest rate swap agreements are accounted for on the accrual basis. Income or expense resulting from these agreements is recorded as an adjustment to interest expense in the period covered. At December 31, 2001, Great Lakes had interest rate swap agreements totaling $100.0 million, 50% of which is consolidated at Range. Two agreements totaling $45.0 million at rates of 7.1% each expire in May 2004. Two agreements of $10.0 million each at 6.2% which expire in December 2002. Five agreements totaling $35.0 million at rates of 4.8%, 4.7%, 4.6%, 4.5% and 4.5% which expire in June of 2003. Range's share of the fair value of the swaps at December 31, 2001, was a net loss of $2.6 million based on current quotes. The agreements expiring in May 2004 may be terminated at the counterparty's option in May 2002. On December 31, 2001, the 30-day LIBOR rate was 1.9%. The value of these swap agreements is marked to market each quarter. In 2001, GLEP incurred additional interest expense of $2.5 million due to interest swaps.

The combined fair value of oil and gas hedging contracts and interest rate swaps, totaling $49.5 million appear as Unrealized derivative hedging gains and Unrealized derivative hedging losses on the balance sheet at December 31, 2001. 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.

(9) COMMITMENTS AND CONTINGENCIES

The Company is involved in various legal actions and claims arising in the ordinary course of business. 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 2001, the Company incurred approximately $480,000 of litigation costs. During 1998, the Company recorded a $2.5 million liability as part of the consideration for the Domain acquisition. The provision was designed to cover the anticipated costs of resolving a shareholder suit and certain other litigation and contingent liabilities. During 2000, certain of the litigation and disputes were settled at a cost including legal fees of $621,000, a level well below that anticipated. As a result, the liability was able to be reduced by $1.0 million which was credited to general and administrative expense. In 2001, a further $817,000 was expended on legal fees and in settlement of litigation and disputes related to the $2.5 million liability.

In 2000, a royalty owner filed a suit asking for a class action certification against Great Lakes and the Company in New York, alleging that gas was sold to affiliates and gas marketers at low prices, inappropriate post production expenses reduced proceeds to the royalty owners, and that Great Lakes improperly accounted for the royalty owners' share of gas. The action sought a proper accounting for all gas sold, an amount equal to the difference in prices paid and the highest obtainable prices, punitive damages and attorneys' fees. The case has been remanded to state court in New York. While the outcome of this suit is uncertain, the Company believes it will be resolved without material adverse effect on its financial position or results of operations.

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 $1.1 million, $1.0 million and $1.1 million in 1999, 2000 and 2001, respectively. Future minimum rental commitments under non-cancelable leases are as follows (in thousands):

2002	$ 820
2003	546
2004	513
2005	501
2006	126
	$2,506

(10) STOCKHOLDERS' EQUITY

In 1995, the Company issued 1,150,000 shares of $2.03 Convertible Exchangeable Preferred Stock (the "$2.03 Preferred") for $28.8 million. The $2.03 Preferred was convertible into 2.632 shares of common stock representing a conversion price of $9.50 per common share. Through December 31, 2000, $23.2 million of the $2.03 Preferred had been exchanged for 4.6 million of common stock. For the twelve months ended December 31, 2001, the majority of the outstanding $2.03 Preferred was exchanged for 767,000 shares of common stock and the remaining shares were repurchased for cash. Gains on exchanges of $2.03 Preferred are not included in net income but they are included in income available to common shareholders for earnings per share purposes. Exchange transactions are not reflected on the cash flow statement because no cash was involved. The elimination of the $2.03 Convertible Preferred stock has reduced the annual dividend requirement by $2.3 million.

The following is a schedule of changes in outstanding common shares:

	Year Ended December 31,	
	2000	2001
Beginning Balance	37,901,789	49,187,682
Issuances:		
Benefit plans	269,714	372,398
Stock options exercised	241,637	223,594
Exchange for:		
6% Debentures	2,496,789	758,597
Trust Preferred	3,231,548	291,211
$2.03 Preferred	4,583,993	766,889
8.75% Senior Notes	-	779,960
Stock Purchase Plan	363,422	263,000
In lieu of dividends	106,597	-
Other	(7,807)	(56)
	11,285,893	3,455,593
Ending Balance	49,187,682	52,643,275

Supplemental disclosures of non-cash investing and financing activities

	Year Ended December 31, 1999 Restated	2000 Restated	2001 Restated
		(in thousands)	
Common stock issued:			
Under benefit plans	$ 1,440	$ 650	$ 1,385
In exchange for fixed income securities	$ 2,978	$ 37,086	$ 14,222
In payment of preferred dividends	$ -	$ 110	$ -

(11) 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. Information with respect to the stock option plans is summarized below:

	Inactive		Active				
	Domain Plan	Domain Directors' Plan	1989 Plan	Directors' Plan	1999 Plan	Total	Average Exercise Price
Outstanding at December 31, 1998	934,141	9,670	2,159,102	140,000	-	3,242,913	$ 8.39
Granted	-	-	904,150	40,000	60,000	1,004,150	2.89
Exercised	(374,264)	-	(70,000)	-	-	(444,264)	0.68
Expired/cancelled	(1,445)	-	(483,562)	(12,000)	-	(497,007)	8.64
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

There were options exercisable of 1,995,242 (weighted average price of $7.81), 1,043,452 (weighted average price of $9.32) and 585,526 (weighted average price of $4.04) at December 31, 1999, 2000 and 2001.

Two years ago, shareholders approved the 1999 Stock Option Plan (the "1999 Plan") providing for the issuance of options on 1.4 million common shares. In May 2001, shareholders approved an increase in the number of options issuable to 3.4 million shares. All options issued under the 1999 Plan vest 25% per year beginning a year after grant and expire in 10 years. During the year-ended December 31, 2001, 774,350 options were granted under the 1999 Plan at exercise prices of $4.17 to $6.67 a share. At December 31, 2001, 1.3 million options were outstanding under the 1999 Plan at exercise prices of $1.94 to $6.67.

The Company also maintains the 1989 Stock Option Plan (the "1989 Plan") which authorized the issuance of options on 3.0 million common shares. Options have been granted under this plan since the 1989 Plan was adopted. Options issued under the 1989 Plan vest 30% after one year, 60% after two years and 100% after three years and expire in 5 years. At December 31, 2001, 542,700 options remained outstanding under the 1989 Plan at exercise prices of $2.63 to $17.75.

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 under the Directors' Plan 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. During the twelve months ended December 31, 2001, 56,000 options were granted under the Directors' Plan at exercise prices of $5.52 to $6.00 a share. At December 31, 2001, 120,000 options were outstanding under the Directors' Plan at exercise prices of $2.81 to $6.00.

The Domain stock option plan was adopted when Domain was acquired, with existing Domain options becoming exercisable into Range common stock. Since August 1998, no further options have been granted under the Plan. At December 31, 2001, 137,484 options remained outstanding under the Plan at a price of $3.46 a share.

In total, 2.1 million options are outstanding at December 31, 2001 at exercise prices ranging from $1.94 to $17.75 as follows:

			Inactive		Active		
Range of Exercise price	Average Exercise price	Weighted Average Remaining Life(Yrs)	Domain Plan	1989 Plan	Directors' Plan	1999 Plan	Total
$1.94-$4.99	$ 2.58	$7.3	137,484	378,487	64,000	563,763	1,143,734
5.00-9.99	6.69	8.2	-	163,713	56,000	751,350	971,063
17.75	17.75	.2	-	500	-	-	500
		Total	137,484	542,700	120,000	1,315,113	2,115,297

In 1997, shareholders approved a Stock Purchase Plan (the "Stock Purchase Plan") authorizing the sale of 900,000 shares of common stock to officers, directors, key employees and consultants. Under the Stock Purchase Plan, the right to purchase shares at prices ranging from 50% to 85% of market value may be granted and there is a one year hold requirement. To date, all purchase rights have been granted at 75% of market. Due to the discount from market value, in the restatement, the Company recorded additional compensation expense of $140,000, $236,000 and $375,000 during 1999, 2000 and 2001, respectively (restated). In May 2001, shareholders approved an increase in the number of shares authorized under the Plan to 1,750,000. Through December 31, 2001, 1,121,319 shares have been sold under the Plan for $4.7 million. At December 31, 2001, rights to purchase 203,000 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 1999, 2000 and 2001 consistent with the provisions of SFAS No. 123, the Company's net income (loss) and earnings (loss) per share would have been reduced to the pro forma amounts indicated below:

	Year Ended December 31,		
	1999 Restated	2000 Restated	2001 Restated
	(in thousands, except per share data)		
As reported -			
Net income (loss)	$ (23,542)	$ 36,578	$ 17,663
Earnings (loss) per share			
-basic	(0.71)	0.97	0.36
-diluted	(0.71)	0.96	0.36
Pro forma -			
Net income (loss)	$ (24,607)	$ 36,412	$ 16,877
Earnings (loss) per share			
-basic	(0.74)	0.97	0.35
-diluted	(0.74)	0.95	0.34

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used for 1999, 2000 and 2001, respectively: fair value of $1.37, $2.14 and $6.50 per share; dividend yields of $0.03, $0 and $0 per share; expected volatility factors of 3.55, 64.89 and 69.80; risk-free interest rates of 5.10%, 5.51% and 4.98%, and an average expected life of six years.

(12) DEFERRED COMPENSATION

In 1996, the Board of Directors of the Company adopted a deferred compensation plan (the Plan) to encourage employees to invest in the shares of the Company. The Plan gives employees the ability to defer all or a portion of their salaries and bonuses and invest in Common Stock of the Company at a discount to market prices 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 is marked-to-market, with any necessary adjustment to general and administrative expense. The Company recorded total expenses related to deferred compensation of $421,000 and $3.5 million in 1999 and 2000 respectively, and a net benefit of $2.1 million in 2001.

(13) BENEFIT PLAN

The Company maintains a 401(k) Plan for its employees. The Plan permits employees to contribute up to 15% of their salary on a pre-tax basis. The Company makes discretionary contributions to the 401(k) Plan annually which are fully vested after four years of service. In 1999, 2000 and 2001, the Company contributed $854,000, $483,000 and $554,000 of common stock (valued at market) to the 401(k) Plan. Employees have a variety of investment options available in the 401K Plan and are encouraged to maintain diversity in accordance with their personnal investment strategy.

(14) INCOME TAXES

The Company's federal income tax provision (benefit) for the years ended December 31, 1999, 2000 and 2001 was $388,000, ($355,000) and $14,505, respectively. The current portion of income tax provision for 1999 represented state income tax payable. A reconciliation between the statutory federal income tax rate and the Company's effective federal income tax rate is as follows:

	Year Ended December 31,		
	1999	2000	2001
		Restated	Restated
Statutory tax rate	(34)%	34%	35 %
Gain on retirement of securities	-	34	10
Permanent differences	-	11	1
Valuation allowance	34	(88)	(45)
State	19	(6)	(1)
Other	-	(14)	(4)
Effective tax rate	19 %	(29)%	0 %
Income taxes paid (refunded)	$388,000	($355,000)	$14,505

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 the Company's deferred tax liabilities and assets are as follows (in thousands):

	December 31, 2000 Restated	December 31, 2001 Restated
Deferred tax assets		
Net operating loss carry over	$ 55,180	$ 53,977
Allowance for doubtful accounts	6,125	7,035
Percentage depletion carryover	4,895	5,256
AMT credits and other	660	660
Total deferred tax assets	72,425	66,928
Deferred tax liabilities		
Depreciation	(54,110)	(54,732)
Unrealized gain on hedging	-	(16,692)
Net deferred tax assets (liabilities)	$ 18,315	$ (4,496)
Valuation allowance	$ (18,315)	$ -

A valuation allowance on the net deferred tax asset was originally established 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 Other comprehensive income (loss), deferred tax assets exceed deferred tax liabilities by $12.2 million. The inclusion of OCI causes 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. As of January 1, 2002, the Company needs to earn approximately $35.0 million of pre-tax income from the unrealized hedge included in OCI at year-end before statutory taxes will be recorded on the statement of operations. Timing of when the Company will record deferred taxes is uncertain.

At December 31, 2001, the Company had regular net operating loss ("NOL") carryovers of $174.3 million and alternative minimum tax ("AMT") NOL carryovers of $155.9 million that expire between 2012 and 2020. 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, 2001, the Company had a statutory depletion carryover of $6.6 million and an AMT credit carryovers of $660,000 which 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)	
2002	$ --	$ --
2003	--	--
2004	--	--
2005	--	--
Thereafter	174,319	155,865
Total	$174,319	$155,865

(15) RESTRUCTURING COSTS

In late 1998, the Company initiated a restructuring plan to reduce costs. The restructuring plan included closing field office, eliminating certain geological and exploration positions, canceling certain exploration and drilling obligations and consolidating administrative functions at the remaining locations. The plan was completed in 1999.

(16) EARNINGS (LOSS) PER COMMON SHARE

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

	Year Ended December 31,		
	1999	2000	2001
	Restated	Restated	Restated
Numerator:			
Income (loss) before extraordinary item	$ (25,972)	$ 18,815	$13,712
Gain on retirement of $2.03 Preferred Stock	-	5,966	556
Preferred dividends	(2,334)	(1,554)	(10)
Numerator for earnings (loss) per share, before extraordinary item	(28,306)	23,227	14,258
Extraordinary item			
Gain on retirement of securities, net	2,430	17,763	3,951
Numerator for earnings (loss) per share, basic and diluted	$ (25,876)	$ 40,990	$18,209
Denominator:			
Weighted average shares	36,933	42,882	51,159
Stock held by employee benefit trust	(407)	(767)	(1,002)
Weighted average shares - basic	36,526	42,115	50,157
Stock held by employee benefit trust	407	767	1,002
Dilutive potential common shares stock options	-	50	106
Denominator for diluted earnings per share	36,933	42,932	51,265
Earnings (loss) per share basic and diluted:			
Before extraordinary item			
Basic	$ (0.78)	$ 0.55	$ 0.28
Diluted	$ (0.78)	$ 0.54	$ 0.28
After extraordinary item			
Basic	$ (0.71)	$ 0.97	$ 0.36
Diluted	$ (0.71)	$ 0.96	$ 0.36

During 2000 and 2001, 75,000 and 129,000 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. In 1999, 18 common shares held by the employee benefit trust are excluded because they are antidilutive.

The Company has and will continue to consider exchanging common stock or other equity-linked securities for fixed income securities. Existing common 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 into common stock, and the price at which fixed income securities are reacquired.

(17) 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 the year ended December 31, 2001, three customers accounted for 10% or more of total oil and gas revenues and the combined sales to those three customers accounted for 50% of total oil and gas revenues. 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, 2001, approximately 91% 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.

(18) OIL AND GAS ACTIVITIES

The following summarizes selected information with respect to producing activities (in thousands):

	Year Ended December 31,		
	1999	2000	2001
	Restated	Restated	Restated
Oil and gas properties:			
Subject to depletion	$ 898,031	$ 947,526	$ 1,021,898
Unproved	61,812	49,523	25,731
Total	959,843	997,049	1,047,629
Accumulated depletion	(389,200)	(443,876)	(514,272)
Net	$ 570,643	$ 553,173	$ 533,357
Costs incurred:			
Acquisition	$ 846	$ 4,701	$ 9,489
Development	30,597	46,032	69,162
Exploration	3,604	4,498	11,405
Total	$ 35,047	$ 55,231	$ 90,056

Acquisition costs in 1999 do not reflect $68 million of value associated with the Company receiving a 50% interest in the reserves contributed by FirstEnergy to Great Lakes. The Company's share of such reserves was 81.6 Bcfe. Exploration costs include capitalized as well as expensed outlays.

(19) 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 interest in Great Lakes' audited financial statements as of or for the year ended December 31, 2001.

	December 31, 2001 (In thousands) Restated
Current assets	$ 15,954
Oil and gas properties, net	168,090
Transportation and field assets, net	15,645
Other assets	110
Current liabilities	11,248
Long-term debt	75,000
Members' equity	111,206
Revenues	52,735
Net income	11,528

(20) GAIN ON FORMATION OF GREAT LAKES

In September 1999, Range transferred all of its Appalachian oil and gas properties and associated gas gathering and transportation systems to Great Lakes in exchange for a 50% ownership interest. Additionally, the Company contributed $188.3 million of indebtedness to Great Lakes. The Great Lakes partners have no commitment to support the operations or obligations of Great Lakes. Range recognized a gain of $30.9 million (restated), which was attributable to the portion of the net assets associated with the 50% interest of the Company's joint venture partner. The gain was calculated by comparing the estimate of the fair value of the assets and liabilities conveyed to their net book value for the assets deemed sold by Range. Great Lakes' DD&A rate is higher than the Company's DD&A rate for its share of such production due to the lower cost basis attributed to Range's investment in Great Lakes versus its proportionate share of Great Lakes assets. DD&A is reduced in consolidation to reflect the Company's investment.

(21) EXTRAORDINARY ITEMS

During 1999, 699,000 shares of common stock were exchanged for $2.3 million of Trust Preferred and $3.6 million of 6% Debentures. 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. Since 1998, there have been 13.6 million shares of common stock exchanged for convertible debt and securities in the amount of $85.4 million. In connection with these exchanges, an extraordinary gain net of costs of $2.4 million, $17.8 million and $4.0 million was recorded in 1999, 2000 and 2001, 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 of $2.03 Preferred were repurchased for $74,000.

(22) 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. Additional background information allows concerning four of the schedules.

Estimated Net Proved Oil and Natural Gas Reserves - Reserves of crude oil, condensate, natural gas liquids and natural gas 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, 2001 to estimate the reserve information 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. The average prices at December 31, 2000 were $24.46 per barrel for oil, $14.91 per barrel for natural gas liquids and $9.57 per Mcf for gas using the benchmark NYMEX prices of $26.80 per barrel and $9.77 per Mmbtu. The average prices at December 31, 1999 were $23.48 per barrel for oil, $15.69 per barrel for natural gas liquids and $2.34 per mcfe for gas using the benchmark NYMEX prices of $25.60 per barrel and $2.44 per Mmbtu.

QUANTITIES OF PROVED RESERVES

	Crude Oil and NGLs (Mbbls)	Natural Gas (Mmcf)	Natural Gas Equivalent (Mmcfe)
Balance, December 31, 1998	27,129	633,317	796,091
Revisions	1,294	(39,298)	(31,534)
Extensions, discoveries and additions	307	11,066	12,908
Purchases	5,241	51,751	83,197
Sales	(2,495)	(162,245)	(177,215)
Production	(2,659)	(50,808)	(66,762)
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	(3,360)	(33,575)	(53,735)
Extensions, discoveries and additions	479	31,542	34,416
Purchases	427	5,761	8,323
Sales	(627)	(190)	(3,952)
Production	(2,242)	(42,278)	(55,730)
Balance, December 31, 2001	20,679	388,927	513,001
PROVED DEVELOPED RESERVES			
December 31, 1999	17,884	299,436	406,740
December 31, 2000	17,215	305,796	409,086
December 31, 2001	14,066	276,162	360,558

The "Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves" ("Standardized Measure") is a disclosure requirement of SFAS No. 69, "Disclosures about Oil and Gas Producing Activities." 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,		
	1999	2000	2001
		(in thousands)	
Future cash inflows	$ 1,689,541	$ 4,697,062	$ 1,397,897
Future costs:			
Production	(486,618)	(755,727)	(471,144)
Development	(189,784)	(177,070)	(176,799)
Future net cash flows	1,013,139	3,764,265	749,954
Income taxes	(131,529)	(457,996)	(87,745)
Total undiscounted future net cash flows	881,610	3,306,269	662,209
10% discount factor	(378,459)	(1,800,007)	(350,801)
Standardized measure	$ 503,151	$ 1,506,262	$ 311,408

CHANGES IN STANDARDIZED MEASURE

	As of December 31,		
	1999	2000	2001
		(in thousands)	
Standardized measure, beginning of year	$ 517,095	$ 503,151	$ 1,506,262
Revisions:			
Prices	128,799	1,184,950	(1,076,168)
Quantities	(37,911)	(89,180)	(8,244)
Estimated future development cost	8,941	36,650	4,620
Accretion of discount	45,420	63,468	196,426
Income taxes	(14,307)	(130,626)	114,556
Net revisions	130,942	1,065,262	(768,810)
Purchases	71,022	8,003	6,245
Extensions, discoveries and additions	16,354	91,855	25,815
Production	(77,884)	(134,556)	(165,033)
Sales	(136,491)	(8,525)	(2,967)
Changes in timing and other	(17,887)	(18,928)	(290,104)
Standardized measure, end of year	$ 503,151	$ 1,506,262	$ 311,408

RANGE RESOURCES CORPORATION

INDEX TO EXHIBITS

(Item 14[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 5-3/4% Preferred Convertible Securities.
4.6	Form of 5-3/4% Convertible Junior Subordinated Debentures.
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 Nonemployee 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.)

Exhibit No.	Description
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
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
10.15.5	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).
10.19	The Amended and Restated Deferred Compensation Plan for Directors and Selected Employees, effective September 1, 2000.
21.1*	Subsidiaries of Registrant.
23.1*	Consent of Independent Public Accountants.
23.2*	Consent of H.J. Gruy and Associates, Inc., independent consulting petroleum engineers.
23.3*	Consent of DeGoyler and MacNaughton, independent consulting petroleum engineers.
23.4*	Consent of Wright and Company, independent consulting engineers.

*Filed herewith.

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. 333-35019) on Form S-3, (No. 333-78231) on Form S-4 and (Nos. 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 dated September 20, 2002 relating to the consolidated balance sheets of Range Resources Corporation and subsidiaries as of December 31, 2000 and 2001, 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, 2001, which report appears in the December 31, 2001 annual report on Form 10-K/A of Range Resources Corporation.

Our report refers to a change in the method of accounting for derivative financial instruments and hedging activities. Our report also refers to the restatement of the Company's consolidated balance sheets as of December 31, 2000 and 2001, and related consolidated statements of operations, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2001, which were audited by other auditors who have ceased operations.

KPMG LLP

Dallas, Texas
October 21, 2002

EXHIBIT 23.2

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

We hereby consent to the use of the name H.J. Gruy and Associates, Inc., and of references to H.J. Gruy and Associates, Inc. and to the inclusion of and references to our report dated February 14, 2002, prepared for Range Resources Corporation in the Range Resources Corporation Annual Report on Form 10-K for the year ended December 31, 2001.

H.J. GRUY AND ASSOCIATES, INC.

March 4, 2002
Houston, Texas

EXHIBIT 23.3

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, 2001, to which this consent is an exhibit. We also consent to the incorporation of information contained in our "Appraisal Report as of December 31, 2001, 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 4, 2002

EXHIBIT 23.4

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, 2001, to which this consent is an exhibit.

WRIGHT AND COMPANY

Brentwood, Tennessee
March 4, 2002