UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark one)

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended March 31, 2005

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ___to ___

Commission file number 0-9592

RANGE RESOURCES CORPORATION

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of Incorporation or organization)	**34-1312571** (I.R.S. Employer Identification No.)

777 Main Street, Suite 800
Fort Worth, Texas
(Address of principal executive offices)

76102
(Zip Code)

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

Former name, former address and former fiscal year, if changed since last report: Not applicable

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 precedings 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☑ No o

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

Yes ☑ No o

81,599,800 Common Shares were outstanding on April 25, 2005.

TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS

The financial statements included herein should be read in conjunction with the latest Form 10-K for Range Resources Corporation. Unless the context otherwise indicates, all references in this report to “Range” “we” “us” or “our” are to Range Resources Corporation and its subsidiaries. The statements are unaudited but reflect all adjustments which, in our opinion, are necessary to fairly present our financial position and results of operations. All adjustments are of a normal recurring nature unless otherwise noted. These financial statements, including selected notes, have been prepared in accordance with the applicable rules of the Securities and Exchange Commission (the “SEC”) and do not include all of the information and disclosures required by accounting principles generally accepted in the United States for complete financial statements.

RANGE RESOURCES CORPORATION
CONSOLIDATED BALANCE SHEET
(In thousands)

	March 31, 2005 (Unaudited)	December 31, 2004
Assets		
Current assets		
Cash and equivalents	$ 18,979	$ 18,382
Accounts receivable, net of allowance for doubtful accounts of $964 and $967 as of March 31, 2005 and December 31, 2004, respectively	63,725	81,942
Unrealized derivative gain (Note 7)	721	534
Deferred tax asset (Note 13)	43,702	26,310
Inventory and other	7,691	9,168
	134,818	136,336
Unrealized derivative gain (Note 7)	130	206
Oil and gas properties, successful efforts method (Note 16)	2,142,476	2,097,026
Accumulated depletion and depreciation	(721,020)	(694,667)
	1,421,456	1,402,359
Transportation and field assets (Note 2)	60,940	59,423
Accumulated depreciation and amortization	(23,568)	(22,141)
	37,372	37,282
Other (Note 2)	23,378	19,223
	$ 1,617,154	$ 1,595,406
Liabilities and Stockholders' Equity		
Current liabilities Accounts payable	$ 62,323	$ 78,723
Asset retirement obligation (Note 3)	5,064	6,822
Accrued liabilities	18,376	23,292
Accrued interest	3,817	7,320
Unrealized derivative loss (Note 7)	116,000	61,005
	205,580	177,162
Bank debt (Note 6)	262,900	423,900
Subordinated notes (Note 6)	346,727	196,656
Deferred taxes, net (Note 13)	119,109	117,713
Unrealized derivative loss (Note 7)	30,517	10,926
Deferred compensation liability (Note 11)	43,790	38,799
Asset retirement obligation (Note 3)	64,434	63,905
Long-term capital lease obligation	2	5
Commitments and contingencies (Note 8)	—	—
Stockholders' equity (Notes 9 and 10) Preferred stock, $1 par, 10,000,000 shares authorized, none issued and outstanding	—	—
Common stock, $.01 par, 100,000,000 shares authorized, 81,537,018 and 81,219,351 issued and outstanding, respectively	815	812
Capital in excess of par value	712,790	707,869
Retained earnings (deficit)	(69,224)	(89,597)
Stock held by employee benefit trust, 1,431,526 and 1,441,751 shares, respectively, at cost (Note 11)	(8,608)	(8,186)
Deferred compensation	(1,186)	(1,257)
Accumulated other comprehensive income (loss) (Note 2)	(90,492)	(43,301)
	544,095	566,340
	$ 1,617,154	$ 1,595,406

See accompanying notes

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENT OF OPERATIONS
(Unaudited, in thousands except per share data)

	Three Months Ended March 31, 2005	Three Months Ended March 31, 2004
Revenues		
Oil and gas sales	$ 107,415	$ 65,368
Transportation and gathering, net	528	467
Other	17	(2,302)
	107,960	63,533
Expenses		
Direct operating	14,808	9,995
Production and ad valorem taxes	5,755	4,250
Exploration	3,271	3,567
General and administrative (Note 11)	10,670	8,821
Interest expense	8,584	4,145
Depletion, depreciation and amortization	29,762	22,248
	72,850	53,026
Income before income taxes	35,110	10,507
Income taxes (Note 13)		
Current	—	—
Deferred	13,107	3,887
	13,107	3,887
Net income	22,003	6,620
Preferred dividends (Note 9)	—	(738)
Net income available to common stockholders	$ 22,003	$ 5,882
Earnings per common share (Note 14):		
Basic:		
Net income	$ 0.28	$ 0.11
Diluted:		
Net income	$ 0.26	$ 0.10
Dividends per common share	$ 0.02	$ —

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENT OF CASH FLOWS
(Unaudited, in thousands)

	Three Months Ended March 31, 2005	Three Months Ended March 31, 2004
Cash flows from operations		
Net income	$ 22,003	$ 6,620
Adjustments to reconcile net income to net cash provided by operations:		
Deferred income tax expense	13,107	3,887
Depletion, depreciation and amortization	29,762	22,248
Unrealized hedging (gains) losses	(308)	755
Allowance for bad debts	225	529
Exploration dry hole costs	483	1,219
Amortization of deferred issuance costs and discount	437	204
Deferred compensation adjustments	4,469	4,558
Loss on sale of assets and other	8	193
Changes in working capital:		
Accounts receivable	17,728	2,964
Inventory and other	(517)	(6,444)
Accounts payable	(13,668)	(2,242)
Accrued liabilities and other	(8,387)	(2,269)
Net cash provided by operations	65,342	32,222
Cash flows from investing		
Additions to oil and gas properties	(45,096)	(22,841)
Additions to field service assets	(1,667)	(445)
Acquisitions	(2,611)	(3,287)
IPF net repayments	509	1,021
Disposal of assets	65	2,323
Net cash used in investing	(48,800)	(23,229)
Cash flows from financing		
Borrowings on credit facilities	86,500	37,500
Repayments on credit facilities	(247,500)	(47,100)
Other debt repayments	(3)	—
Debt issuance costs	(3,100)	—
Dividends paid – common stock	(1,630)	(564)
– preferred stock	(2,213)	(738)
Issuance of subordinated notes	150,000	—
Issuance of common stock	2,001	2,191
Net cash used in financing	(15,945)	(8,711)
Increase in cash and equivalents	597	282
Cash and equivalents, beginning of period	18,382	631
Cash and equivalents, end of period	$ 18,979	$ 913

See accompanying notes.

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME (LOSS)
(Unaudited, in thousands)

	Three Months Ended March 31,	
	2005	2004
Net income	$ 22,003	$ 6,620
Net deferred hedge gains (losses), net of tax:		
Contract settlements reclassified to income	13,190	11,126
Change in unrealized deferred hedging gains (losses)	(60,117)	(26,292)
Change in unrealized gains (losses) on securities held by deferred compensation plan	(264)	47
Comprehensive income (loss)	$ (25,188)	$ (8,499)

See accompanying notes.

RANGE RESOURCES CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

(1) ORGANIZATION AND NATURE OF BUSINESS

We are engaged in the exploration, development and acquisition of oil and gas properties primarily in the Southwestern, Appalachian and Gulf Coast regions of the United States. We seek to increase our reserves and production primarily through drilling and complementary acquisitions. Prior to June 2004, we held our Appalachian oil and gas assets through a 50% owned joint venture, Great Lakes Energy Partners L.L.C., or Great Lakes. In June 2004, we purchased the 50% of Great Lakes that we did not own (see footnote 4). We also added substantially to our Appalachian oil and gas assets through the acquisition of PMOG Holdings, Inc., or Pine Mountain, in December 2004. Range is a Delaware corporation whose common stock is listed on the New York Stock Exchange.

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The accompanying consolidated financial statements include the accounts of Range, our wholly-owned subsidiaries and for the periods prior to June 23, 2004, a 50% pro rata share of the assets, liabilities, income and expenses of Great Lakes. On June 23, 2004, we purchased the 50% of Great Lakes that we did not own (see footnote 4). The statement of operations for the three months ended March 31, 2004 includes 50% of the revenues and expenses of Great Lakes while the three months ended March 31, 2005 includes 100%. Certain reclassifications have been made to the presentation of prior periods to conform to current year presentation. These financial statements are unaudited but, in our opinion, reflect all adjustments necessary for a fair presentation of the results for the periods presented. All such adjustments are of a normal recurring nature unless disclosed otherwise.

Revenue Recognition and Credit Risk

We recognize revenues from the sale of products and services in the period delivered. Although receivables are concentrated in the oil and gas industry, we do not view this as an unusual credit risk. We provide for an allowance for doubtful accounts for specific receivables judged unlikely to be collected based on the age of the receivable, our experience with the debtor, potential offsets to the amount owed and economic conditions. In certain instances, we require purchasers to post stand-by letters of credit, furnish guarantees or pre-pay purchases. In addition to the allowance for doubtful accounts for Independent Producer Finance, or IPF, we have allowances for doubtful accounts relating to exploration and production of $964,000 and $967,000 at March 31, 2005 and December 31, 2004, respectively.

Cash and Equivalents

Cash and equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with maturities of three months or less. The March 31, 2005 balance sheet includes $16.8 million of cash in an escrow account. These funds are proceeds received from the sale of oil and gas properties which are held in escrow to be used to purchase similar assets. We may defer the tax due on the sale of assets if we purchase similar assets by April 29, 2005.

Oil and Gas Properties

We follow the successful efforts method of accounting for oil and gas producing activities. Exploratory drilling costs are capitalized pending determination of whether a well is successful. Exploratory wells subsequently determined to be dry holes are charged to expense. Costs resulting in exploratory discoveries and all development costs, whether successful or not, are capitalized. Geological and geophysical costs, delay rentals and unsuccessful exploratory wells are expensed. Depletion is provided on the unit-of-production method. Oil and NGLs are converted to gas equivalent basis (“mcfe”) at the rate of one barrel equals 6 mcf. The depletion, depreciation and amortization (“DD&A”) rates were $1.45 per mcfe and $1.38 per mcfe in the three months ended March 31, 2005 and 2004, respectively. Unproved properties had a net book value of $15.7 million and $14.8 million at March 31, 2005 and December 31, 2004, respectively. Unproved properties are reviewed quarterly for impairment and impaired if conditions indicate we will not explore the acreage prior to expiration or the carrying value is above fair value.

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

Transportation and Field Assets

Our gas transportation and gathering systems are generally located in proximity to certain of our principal fields. Depreciation on these systems is provided on the straight-line method based on estimated useful lives of 10 to 15 years. We receive third-party income for providing certain transportation and field services which is recognized as earned. Depreciation on the field assets is calculated on the straight-line method based on estimated useful lives of five to seven years. Buildings are depreciated over 10 to 15 years.

Independent Producer Finance

IPF owns dollar denominated overriding royalties in oil and gas properties. The royalties are accounted for as receivables and payments received relating to the return on investment are recognized as income with the remaining receipts reducing receivables. Currently, all receipts are being recognized as a return of capital, thus reducing receivables. The receivables are evaluated quarterly and provisions for the valuation allowance are adjusted accordingly. At March 31, 2005, the receivable balance was $7.1 million, offset by a valuation allowance of $3.1 million resulting in a net receivable balance of $4.0 million. The $4.0 million net receivable is shown on our consolidated balance sheet in other assets ($3.1 million) and accounts receivable ($0.9 million). At December 31, 2004, the receivable balance was $7.4 million, offset by a valuation allowance of $2.9 million resulting in a net receivable balance of $4.5 million. During the first quarter of 2005, IPF net (included in other revenues) included $49,000 of administrative expenses and a $225,000 increase in the valuation allowance. During the same period of the prior year, revenues of $33,000 were offset by $465,000 of interest and administrative expenses, and a $235,000 increase in the valuation allowance. Since 2001, IPF has not acquired any new royalties and therefore, the portfolio has declined due to collections and sales.

Other Assets

The expenses of issuing debt are capitalized and included in other assets on our consolidated balance sheet. These costs are amortized over the expected life of the related securities. When a security is retired prior to maturity, related unamortized costs are expensed. At March 31, 2005 and December 31, 2004, these capitalized costs totaled $8.8 million and $5.7 million, respectively. At March 31, 2005, other assets included $8.8 million of unamortized debt issuance costs, $540,000 of long-term deposits, $10.8 million of marketable securities held in our deferred compensation plans and $3.1 million of long-term IPF receivables.

Gas Imbalances

We use the sales method to account for gas imbalances, recognizing revenue based on cash received rather than the gas produced. A liability is recognized when the imbalance exceeds the estimate of remaining reserves. Gas imbalances at March 31, 2005 and December 31, 2004 were not significant.

Derivative Financial Instruments and Hedging

We use commodity-based derivatives to reduce the impact of volatile oil and gas prices. For derivatives qualifying as hedges of future cash flows, the effective portion of any changes in fair value is recognized in a component of stockholders' equity called other comprehensive income, or OCI, and then reclassified to income, within oil and gas revenues, when the underlying anticipated transaction occurs. Any ineffective portion (changes in realized prices that do not match changes in the hedge price) is recognized in income, in other revenues in our consolidated statement of operations, as it occurs. Ineffective gains or losses are recorded while the hedge contract is open and may increase or reverse until settlement of the contract. Of the $146.5 million unrealized pre-tax hedging loss at March 31, 2005, $116.0 million of losses will be reclassified to earnings over the next 12 months period and $30.5 million for the periods thereafter, if prices remain constant. Actual amounts that will be reclassified will vary as a result of changes in prices. We have also entered into swap agreements to reduce the risk of changing interest rates. Due to the Great Lakes acquisition and changes to our credit facility, these interest rate swaps are no longer designated as hedges and are marked to market each month in interest expense.

Asset Retirement Obligation

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

Use of Estimates

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

Recent Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 123 (revised 2004), Share-Based Payment, which is a revision of FASB Statement No. 123, Accounting for Stock-Based Compensation. Statement 123 (R) supersedes APB opinion No. 25, Accounting for Stock Issued to employees, and amends FASB Statement No. 95, Statement of Cash Flows. Generally, the approach in Statement 123 (R) is similar to the approach described in Statement 123. However, Statement 123 (R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their fair values. Pro forma disclosure is no longer an alternative. We are continuing to evaluate the alternatives allowed under the standard, which we are required to adopt beginning in the first quarter of 2006.

Pro Forma Stock-Based Compensation

We have adopted the disclosure-only provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," or SFAS 123. Accordingly, no compensation cost has been recognized for the stock option plans because the exercise prices of employee stock options equals the market prices of the underlying stock on the date of grant. If compensation cost had been determined based on the fair value at the grant date for awards in the three months ended March 31, 2005 and 2004, consistent with the provisions of SFAS 123, our net income and earnings per share would have been reduced to the pro forma amounts indicated below (in thousands, except per share data):

	Three Months Ended March 31,	
	2005	2004
Net income, as reported	$ 22,003	$ 6,620
Plus: Total stock-based employee compensation cost included in net income, net of tax	2,815	2,871
Deduct: Total stock-based employee compensation, under fair value based method, net of tax	(4,865)	(4,113)
Pro forma net income	$ 19,953	$ 5,378
Earnings per share:		
Basic-as reported	$ 0.28	$ 0.11
Basic-pro forma	$ 0.25	$ 0.08
Diluted-as reported	$ 0.26	$ 0.10
Diluted-pro forma	$ 0.24	$ 0.08

(3) ASSET RETIREMENT OBLIGATION

A reconciliation of our liability for plugging and abandonment costs for the three months ended March 31, 2005 and 2004 is as follows (in thousands):

	Three Months Ended March 31,	
	2005	2004
Asset retirement obligation beginning of period	$ 70,727	$ 51,844
Liabilities incurred	569	427
Liabilities settled	(1,910)	(1,881)
Accretion expense	1,286	1,096
Change in estimate	(939)	(19)
Asset retirement obligation end of period	$ 69,733	$ 51,467

(4) ACQUISITIONS AND DISPOSITIONS

Acquisitions are accounted for as purchases, and accordingly, the results of operations are included in our consolidated statement of operations from the respective date of acquisition. Purchase prices are allocated to acquired assets and assumed liabilities based on their estimated fair value at acquisition. Acquisitions have been funded with internal cash flow, bank borrowings and the issuance of debt and equity securities. We purchased various properties for $2.6 million and $3.3 million during the three months ended March 31, 2005 and 2004, respectively. The purchases include $370,000 and $1.8 million for proved oil and gas reserves, respectively, with the remainder representing unproved acreage.

Table of Contents

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

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

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

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

The following unaudited pro forma data includes the results of operations of the above acquisitions as if they had been consummated at the beginning of 2004. The pro forma data is based on historical information and does not necessarily reflect the actual results that would have occurred nor is it necessarily indicative of future results of operations (in thousands).

	Three Months Ended March 31,	
	2005	2004
Revenues	$ 107,960	$ 85,467
Income before income taxes	35,110	17,644
Net income	22,003	11,115
Earnings per common share:		
- Basic	$ 0.28	$ 0.14
- Diluted	$ 0.26	$ 0.14

During the first quarter of 2004, we sold non-strategic properties for proceeds of $2.3 million. Proceeds from the disposal of miscellaneous properties depreciated on a group basis are credited to net book value with no immediate effect on income. However, gain or loss is recognized from the sale of less than the entire amortization base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base.

(5) SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended March 31,	
	2005	2004
	(in thousands)	
Non-cash investing and financing activities:		
Common stock issued under benefit plans	$ 720	$ 305
Cash used in operating activities included:		
Income taxes paid	$ —	$ 150
Interest paid	$ 11,811	$ 6,370

(6) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (in thousands) (interest rates at March 31, 2005, excluding the impact of interest rate swaps, is shown parenthetically). No interest expense was capitalized during the three months ended March 31, 2005 and 2004, respectively.

	March 31, 2005	December 31, 2004
Bank debt (4.1%)	$ 262,900	$ 423,900
Subordinated debt:		
7-3/8% Senior Subordinated Notes due 2013, net of discount	196,727	196,656
6-3/8% Senior Subordinated Notes due 2015	150,000	—
Total debt	$ 609,627	$ 620,556

Bank Debt

In June 2004, we entered into an amended and restated $600.0 million revolving bank facility, which is secured by substantially all of our assets. The bank credit facility provides for a borrowing base subject to redeterminations semi-annually each April and October and pursuant to certain unscheduled redeterminations. At March 31, 2005, the outstanding balance under the bank credit facility was $262.9 million and there was $312.1 million of borrowing capacity available. As of April 15, 2005, the loan maturity was extended one year to January 1, 2009, the borrowing base was increased to $600.0 million and certain reductions to interest rate margins and fees were enacted. Borrowings under the bank credit facility can either be base rate loans or LIBOR loans. On all base rate loans, the rate per annum is equal to the lesser of (i) the maximum rate (the "weekly ceiling" as defined in Section 303 of the Texas Finance Code or other applicable laws if greater) (the "Maximum Rate") or, (ii) the sum of (A) the higher of (1) the prime rate for such date, or (2) the sum of the federal funds effective rate for such data plus one-half of one percent (0.50%) per annum, plus a base rate margin of between 0.0% to 0.625% per annum depending on the total outstanding under the bank credit facility relative to the borrowing base. On all LIBOR loans, we pay a varying rate per annum equal to the lesser of (i) the Maximum Rate, or (ii) the sum of the quotient of (A) the LIBOR base rate, divided by (B) one minus the reserve requirement applicable to such interest period, plus a LIBOR margin of between 1.25% and 1.875% per annum depending on the total outstanding under the bank credit facility relative to the borrowing base. We may elect, from time-to-time, to convert all or any part of its LIBOR loans to base rate loans or to convert all or any part of its base rate loans to LIBOR loans. The average interest rate on the bank credit facility, excluding the effect of interest rate swaps, was 4.1% for the three months ended March 2005. After the effect of the interest rate swaps (see Note 7), the rate was 3.9% for the three months ended March 2005. The weighted average interest rate (including applicable margin) was 3.1% for the three months ended March 31, 2004. A commitment fee is paid on the undrawn balance based on an annual rate of between 0.25% and 0.50%. At March 31, 2005, the commitment fee was 0.25% and the interest rate margin was 1.25%. At April 25, 2005, the interest rate (including applicable margin) was 3.9% excluding interest rate swaps and 3.6% after interest rate swaps.

Great Lakes Credit Facility

Prior to June 23, 2004, we consolidated our proportionate share of borrowings on the Great Lakes $275.0 million bank facility, or the Great Lakes Credit Facility. Simultaneously with our purchase of the 50% of Great Lakes we did not own, the outstanding balance under the Great Lakes Credit Facility was fully repaid.

7-3/8% Senior Subordinated Notes due 2013

In July 2003, we issued $100.0 million of 7-3/8% Senior Subordinated Notes due 2013, or the 7-3/8% Notes. We pay interest on the 7-3/8% Notes semi-annually each January and July of each year. The 7-3/8% Notes mature in July 2013 and are guaranteed by certain of our subsidiaries, or the Subsidiary Guarantors. The 7-3/8% Notes were issued at a discount which is amortized into interest expense over the life of the 7-3/8% Notes into interest expense.

We may redeem the 7-3/8% Notes, in whole or in part, at any time on or after July 15, 2008, at redemption prices from 103.7% of the principal amount as of July 15, 2008, and declining to 100.0% on July 15, 2011 and thereafter. Prior to July 15, 2006, we may redeem up to 35% of the original aggregate principal amount of the notes at a redemption price of 107.4% of the principal amount thereof plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings. If we experience a change of control, there may be a requirement to repurchase all or a portion of the 7-3/8% Notes at 101% of the principal amount plus accrued and unpaid interest, if any. The 7-3/8% Notes and the guarantees by the Subsidiary Guarantors are general, unsecured obligations and are subordinated to our senior debt and will be subordinated to future senior debt that Range and the Subsidiary Guarantors are permitted to incur under the bank credit facility and the indenture governing the 7-3/8% Notes. In June 2004, we issued an additional $100.0 million of 7-3/8% Notes, or the Additional Notes. The Additional Notes were issued at a $1.9 million discount which is amortized into interest expense over the remaining life of the 7-3/8% Senior Notes.

6-3/8% Senior Subordinated Notes Due 2015

In March 2005, we issued $150.0 million of 6-3/8% Senior Subordinated Notes due 2015, or the 6-3/8% Notes. We pay interest on the 6-3/8% Notes semi-annually each March and September of each year. The offering of the 6-3/8% Notes on March 9, 2005 was not registered under the Securities Act of 1933, as amended, or the Securities Act, or under any state securities laws because the 6-3/8% Notes were only offered to qualified institutional buyers and to non-U.S. persons outside the United States in compliance with Rule 144A and Regulation S under the Securities Act.

6% Convertible Subordinated Debentures due 2007

In 1996, we issued $55.0 million of 6% Convertible Subordinated Debentures due 2007, or the 6% Debentures. We redeemed the outstanding 6% Debentures in August 2004 at 102.0% of principal amount, plus accrued interest, which totaled $9.1 million.

Debt Covenants

The debt agreements contain covenants relating to working capital, dividends and financial ratios. We were in compliance with all covenants at March 31, 2005. Under the bank credit facility, common and preferred dividends are permitted, subject to the provisions of the restricted payment basket. The bank credit facility provides for a restricted payment basket of $20.0 million plus 50% of net income plus 66-2/3% of net cash proceeds from common stock issuances. Approximately $258.7 million was available under the bank credit facility's restricted payment basket on March 31, 2005. The terms of both the 6-3/8% Notes and the 7-3/8% Notes limit restricted payments (including dividends) to the greater of $20.0 million or a formula based on earnings and equity issuances since the original issuance of the notes. At March 31, 2005, approximately $277.3 million was available under both the 6-3/8% Notes and the 7-3/8% Notes restricted payments basket.

(7) FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

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

The following table sets forth the book and estimated fair values of financial instruments as of March 31, 2005 and December 31, 2004 (in thousands):

	March 31, 2005		December 31, 2004	
	Book Value	Fair Value	Book Value	Fair Value
Assets				
Cash and equivalents	$ 18,979	$ 18,979	$ 18,382	$ 18,382
Accounts receivable	62,837	62,837	80,562	80,562
IPF receivables	888	888	4,508	4,508
Marketable securities	10,842	10,842	9,866	9,866
Interest rate swaps	851	851	740	740
Total	94,397	94,397	114,058	114,058
Liabilities Accounts payable	(62,323)	(62,323)	(78,723)	(78,723)
Commodity swaps and collars	(146,517)	(146,517)	(71,931)	(71,931)
Long-term debt (1)	(609,627)	(610,900)	(620,556)	(633,556)
Total	(818,467)	(819,740)	(771,210)	(784,210)
Net financial instruments	$(724,070)	$(725,343)	$(657,152)	$(670,152)

(1) Fair value based on quotes received from certain brokerage firms. Quotes as of March 31, 2005 were 102% for the 7-3/8% Notes and 96% for the 6-3/8% Notes.

At March 31, 2005, we had open hedging contracts covering 13.5 Bcf of gas at prices averaging $4.22 per mcf, 0.5 million barrels of oil at prices averaging $29.42 per barrel and 0.2 million barrels of NGLs at prices averaging $19.20 per barrel. We also had collars covering 37.9 Bcf of gas at weighted averaged floor and cap prices of $5.14 to $8.34 per mcf and 3.0 million barrels of oil at weighted average floor cap prices of $29.84 to $43.63 per barrel. Their fair value, represented by the estimated amount that would be realized upon termination, based on a comparison of the contract prices and a reference price, generally New York Mercantile Exchange, or the NYMEX, on March 31, 2005, was a net unrealized pre-tax loss of $146.5 million. The contracts expire monthly through December 2006. Transaction gains and losses on settled contracts are determined monthly and are included as increases or decreases to oil and gas revenues in the period the hedged production is sold. Oil and gas revenues were decreased by $20.9 million and $16.9 million due to hedging in the three months ended March 31, 2005 and 2004, respectively. Other revenues in our consolidated statement of operations include ineffective hedging gains of $125,000 and losses of $1.6 million in the three months ended March 31, 2005 and 2004, respectively.

The following schedule shows the effect of closed oil, gas and NGL hedges since January 1, 2004 and the value of open contracts at March 31, 2005 (in thousands):

Quarter Ended	Hedging Gain (Loss)
Closed Contracts	
2004	
March 31	$ (16,896)
June 30	(23,245)
September 30	(24,382)
December 31	(35,598)
Subtotal	(100,121)
2005	
March 31	(20,936)
Subtotal	(20,936)
Total net realized loss	$ (121,057)
Open Contracts	
2005	
June 30	$ (30,158)
September 30	(34,440)
December 31	(37,883)
Subtotal	(102,481)
2006	
March 31	(13,519)
June 30	(10,295)
September 30	(10,061)
December 31	(10,161)
Subtotal	(44,036)
Total net liability	$ (146,517)

We use interest rate swap agreements to manage the risk that future cash flows associated with interest payments on certain amounts outstanding under the variable rate bank credit facility may be adversely affected by volatility in market rates. Under the interest rate swap agreements, we agree to pay an amount equal to a specified fixed rate of interest times a notional principal amount, and to receive in return, a specified variable rate of interest times the same notional principal amount. Changes in the fair value of interest rate swaps, which qualify for cash flow hedge accounting treatment, are reflected as adjustments to OCI to the extent the swaps are effective and are recognized as an adjustment to interest expense during the period in which the cash flow related to the interest payments are made. Due to the Great Lakes acquisition, these interest rate swaps are no longer designated as hedges and are marked to market each month in interest expense. At March 31, 2005, we had three interest rate swap agreements with a notional amount of $45.0 million. These swaps consist of one agreement for $10.0 million at 1.4% which expires in June 2005 and two agreements totaling $35.0 million at 1.8% which expire in June 2006. The fair value of the swaps at March 31, 2005 was a net unrealized pre-tax gain of $851,000.

The combined fair value of net unrealized losses on oil and gas hedges and net unrealized gain on interest rate swaps totaled $145.7 million and appear as short-term and long-term unrealized derivative gains and losses on the balance sheet. Hedging activities are conducted with major financial and commodities trading institutions which we believe are acceptable credit risks. At times, such risks may be concentrated with certain counterparties. The creditworthiness of the counterparties is subject to continuing review.

The following table sets forth quantitative information of derivative instruments at March 31, 2005 (in thousands):

	As of March 31, 2005	
	Assets	Liabilities
Commodity swaps	$ —	$ (63,571)(a)
Commodity collars	$ —	$ (82,946)(b)
Interest rate swaps	$ 851	$ —

(a) $57.6 million and $6.0 million is expected to be reclassified to income in 2005 and 2006, respectively, if prices remain constant.

(b) $44.9 million and $38.1 million is expected to be reclassified to income in 2005 and 2006, respectively, if prices remain constant.

(8) COMMITMENTS AND CONTINGENCIES

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

(9) STOCKHOLDERS' EQUITY

We have authorized capital stock of 110 million shares, which includes 100 million shares of common stock and 10 million shares of preferred stock. In September 2003, we issued 1.0 million shares of Convertible Preferred, par value $1.00 and liquidation preference $50 per share. Effective December 31, 2004, all outstanding shares of Convertible Preferred were converted into 5.9 million shares of common stock.

The following is a schedule of changes in the number of outstanding common shares from December 31, 2003 to March 31, 2005:

	Three Months Ended March 31, 2005	Twelve Months Ended December 31, 2004
Beginning balance	81,219,351	56,409,791
Issuances:		
Public offerings	—	17,940,000
Stock options exercised	286,684	834,537
Restricted stock grants	—	80,900
Deferred compensation plan	13,923	3,671
In lieu of fees and bonuses	17,060	30,459
Contributed to 401(k) plan	—	37,640
Exchanged for:		
5.9% Convertible Preferred	—	5,882,353
	317,667	24,809,560
Ending balance	81,537,018	81,219,351

(10) STOCK OPTION AND PURCHASE PLANS

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

	Active		Inactive		
	1999 Plan	Non-Employee Plan	Directors' Plan	1989 Plan	Total
Outstanding on December 31, 2004	4,262,220	—	232,000	87,850	4,582,070
Granted	983,050	—	—	—	983,050
Exercised	(281,384)	—	—	(5,300)	(286,684)
Expired/forfeited	(50,087)	—	—	(750)	(50,837)
	651,579	—	—	(6,050)	645,529
Outstanding on March 31, 2005	4,913,799	—	232,000	81,800	5,227,599

In 1999, shareholders approved a stock option plan, or the 1999 Plan, under which 9.25 million options can be granted. All options issued under the 1999 Plan through May 2002 vest over 4 years and have a maximum term of 10 years, while options issued after May 2002 vest over a three year period and have a maximum term of five years. During the three months ended March 31, 2005, 983,050 options were granted to eligible employees at an exercise price of $23.28 a share. At March 31, 2005, 4.9 million options were outstanding at exercise prices ranging from $1.94 to $23.28 a share.

In 1994, shareholders approved the Outside Directors' Stock Option Plan, or the Directors' Plan, where up to 300,000 options can be granted. Director's options are granted upon initial election as a director and annually upon a director's re-election at the annual meeting. At March 31, 2005, 232,000 options were outstanding under the Directors' Plan at exercise prices ranging from $2.81 to $11.30 a share. No further options will be granted under this plan.

On May 19, 2004, shareholders approved the Non-Employee Director Stock Option Plan, or the Non-Employee Plan. The maximum number of options issuable is 300,000. The term of the options will not exceed a period of ten years. At March 31, 2005, there were no options outstanding under this plan.

We maintain the 1989 Stock Option Plan, or the 1989 Plan, which authorized the issuance of 3.0 million options. No options have been granted under the plan since March 1999. Options issued under the 1989 Plan vested over a three year period and expire in ten years. At March 31, 2005, 81,800 options remained outstanding under the 1989 Plan at exercise prices ranging from $2.63 to $7.63 a share. The last of these options expire in 2009.

At March 31, 2005, 5.2 million options were outstanding at exercise prices of $1.94 to $23.28 a share as follows:

		Active		Inactive	
Range of Exercise Prices	Average Exercise Price	1999 Plan	Directors' Plan	1989 Plan	Total
$ 1.94 - $ 4.99	$ 3.57	407,096	48,000	72,500	527,596
$ 5.00 - $ 9.99	$ 5.85	2,040,553	136,000	9,300	2,185,853
$ 10.00 - $14.99	$ 10.55	1,176,950	48,000	—	1,224,950
$ 15.00 - $19.99	$ 16.16	307,200	—	—	307,200
$ 20.00 - $23.28	$ 23.28	982,000	—	—	982,000
Total		4,913,799	232,000	81,800	5,227,599

In 1997, shareholders approved a stock purchase plan where up to 1.75 million shares of common stock could be sold to officers, directors, 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. To date, all purchase rights have been granted at 75% of market. At March 31, 2005, there were no rights outstanding to purchase shares.

During 2003, we issued 234,000 restricted shares of our common stock as compensation to directors, officers and employees at an average price of $6.40. The restricted share awards included 136,000 issued to directors (which vested immediately) and 98,000 to officers and employees with vesting over a three year period. In 2004, we issued 80,900 shares of restricted stock grants as compensation to directors, officers and employees at an average price of $11.90. The restricted grants included 24,000 issued to directors (with immediate vesting) and 56,900 to officers and employees with vesting over a three year period. We recorded compensation expense based upon the fair market value of the shares on the date of grant of $174,000 and $116,500 during the three month periods ended March 31, 2005 and 2004 related to these grants.

(11) DEFERRED COMPENSATION

In 1996, the Board of Directors adopted a deferred compensation plan, or the Plan. The Plan gives directors, certain officers and key employees the ability to defer all or a portion of their salaries and bonuses and invests such amounts in our common stock or makes other investments at the employee's discretion. Great Lakes also had a deferred compensation plan that allowed certain employees to defer all or a portion of their salaries and bonuses and invest such amounts in certain investments at the employee's discretion. In late December 2004, in connection with the recent changes to regulations governing deferred compensation plans, we adopted the Range Resources Corporation Deferred Compensation Plan, or the 2005 Deferred Compensation Plan. The 2005 Deferred Compensation Plan is intended to operate in a manner substantially similar to the old plans, subject to new requirements and changes mandated under Section 409A of the Internal Revenue Code. The old plans were frozen and will not receive additional contributions. The assets of the plans are held in a rabbi trust, or the Rabbi Trust, and are available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Our stock held in the Rabbi Trust is treated in a manner similar to treasury stock with an offsetting amount reflected as a deferred compensation liability and the carrying value of the deferred compensation liability is adjusted to fair value each reporting period by a charge or credit to general and administrative expense on our consolidated statement of operations. The assets of the Rabbi Trust, other than common stock, is invested in marketable securities and reported at market value in other assets on our consolidated balance sheet. The deferred compensation liability on our balance sheet reflects the market value of the securities held in the Rabbi Trust. The cost of common stock held in the Rabbi Trust is shown as a reduction to stockholder's equity. Changes in the market value of the marketable securities are reflected in OCI, while changes in the market value of the common stock held in the Rabbi Trust is charged or credited to general and administrative expense each quarter. We recorded mark-to-market expense related to deferred compensation of $4.1 million and $4.4 million in the three months ended March 31, 2005 and 2004, respectively.

(12) BENEFIT PLAN

We maintain a 401(k) plan for our employees that permit employees to contribute a portion of their salary, subject to Internal Revenue Service limitations. Historically, we have made discretionary contributions of our common stock to the 401(k) Plan annually. Effective January 1, 2005, we began matching employee contributions up to 3% in cash. Great Lakes also had a 401(k) in which their contributions were made in cash. The Great Lakes 401(k) plan was merged into the Range plan effective January 1, 2005. All of our contributions become fully vested after the individual employee has three years of service with us. In 2004, 2003 and 2002, we contributed $1.2 million, $912,000 and $877,000 respectively, to the 401(k) plan. We do not require that employees hold the contributed stock in their account. Employees have a variety of investment options in the 401(k) plan and may, at any time, diversify out of our common stock based on their personal investment strategy.

(13) INCOME TAXES

The significant components of deferred tax liabilities and assets on March 31, 2005 and December 31, 2004 were as follows (in thousands):

	March 31, 2005	December 31, 2004
Deferred tax assets (liabilities) Net unrealized loss in OCI	$ 53,941	$ 25,930
Other	(129,348)	(117,333)
Net deferred tax liability	$ (75,407)	$ (91,403)

At December 31, 2004, deferred tax liabilities exceeded deferred tax assets by $91.4 million with $26.0 million of deferred tax assets related to deferred hedging losses included in OCI. At March 31, 2005, deferred tax liabilities exceeded deferred tax assets by $75.4 million with $53.9 million of deferred tax assets related to hedging losses in OCI.

At December 31, 2004, we had regular net operating loss, or NOL, carryovers of $237.2 million and alternative minimum tax, or AMT, NOL carryovers of $205.9 million that expire between 2012 and 2023. At December 31, 2004, we had AMT credit carryovers of $1.8 million that are not subject to limitation or expiration.

Table of Contents

(14) COMPUTATION OF EARNINGS PER SHARE

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

	Three Months Ended March 31, 2005	Three Months Ended March 31, 2004
Numerator:		
Net income	$ 22,003	$ 6,620
Preferred dividends	—	(738)
Numerator for basic and diluted earnings per share	$ 22,003	$ 5,882
Denominator:		
Weighted average shares outstanding	81,353	56,646
Stock held in the deferred compensation plan	(1,441)	(1,672)
Weighted average shares, basic	79,912	54,974
Effect of dilutive securities:		
Weighted average shares outstanding	81,353	56,646
Employee stock options and other	1,714	1,092
Dilutive potential common shares for diluted earnings per share	83,067	57,738
Earnings per common share:		
- Basic	$ 0.28	$ 0.11
- Diluted	$ 0.26	$ 0.10

Options to purchase 982,000 and 19,500 shares of common stock were outstanding but not included in the computations of diluted net income per share for the three months ended March 31, 2005 and 2004, respectively, because the exercise prices of the options were greater than the average market price of the common shares and would be anti-dilutive to the computations. Prior to its redemption in December 2004, 5.9 million shares of convertible preferred stock were excluded from the dilutive calculation for the quarter ended March 31, 2004 as the effect was antidilutive.

(15) MAJOR CUSTOMERS

We market our production on a competitive basis. Gas is sold under various types of contracts including month-to-month and one-to-five year contracts to short-term contracts that are cancelable within 30 days. The price for oil is generally equal to a posted price set by major purchasers in the area. We sell to oil purchasers on the basis of price and service and may be changed on 30 days notice. For the three months ended March 31, 2005, two customers accounted for 10% or more of total oil and gas revenues and the combined sales to those two customers accounted for 12% and 10% of total oil gas revenues, respectively. We believe that the loss of any one customer would not have a material long-term adverse effect on our results.

(16) OIL AND GAS ACTIVITIES

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

	March 31, 2005	December 31, 2004
Oil and gas properties:		
Properties subject to depletion	$ 2,126,804	$ 2,082,236
Unproved properties	15,672	14,790
Total	2,142,476	2,097,026
Accumulated depletion	(721,020)	(694,667)
Net	$ 1,421,456	$ 1,402,359

	Three Months Ended March 31, 2005	Twelve Months Ended December 31, 2004
Costs incurred:		
Acquisitions:		
Acreage purchases	$ 2,241	$ 9,690
Unproved leasehold acquired	—	4,043
Proved oil and gas properties	370	522,126
Purchase price adjustment (a)	—	79,352
Asset retirement obligations	—	17,524
Subtotal	2,611	632,735
Development	43,148	144,007
Exploration (b)	6,389	31,830
Gas gathering facilities		
Acquisitions	—	15,539
Development	1,399	4,778
Subtotal	53,547	828,889
Asset retirement obligations	(425)	3,994
Total	$ 53,122	$ 832,883

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

(b) Includes $3,271 and $21,219 of exploration costs expensed in the three months ended March 31, 2005 and the twelve months ended December 31, 2004, respectively.

Item 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Factors Affecting Financial Condition and Liquidity

Critical Accounting Policies

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

Property, Plant and Equipment

Proved reserves are defined by the SEC as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although our engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. Reserves estimates are updated at least annually and consider recent production levels and other technical information. Estimated reserves are often subject to future revision, which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price and cost changes, and other economic factors. Changes in oil and gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions in turn cause adjustments in the depletion rates utilized by us. We cannot predict what reserve revisions may be required in future periods.

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

We utilize the successful efforts method to account for exploration and development expenditures. Unsuccessful exploration wells are expensed and can have a significant effect on reported operating results. Successful exploration drilling costs and all development costs are capitalized and systematically charged to expense using the units of production method based on proved developed oil and gas reserves as estimated by our engineers and reviewed by independent engineers. Proven property leasehold costs are charged to expense using the units of production method based on total proved reserves. Unproved properties are assessed periodically and impairments to value are charged to expense.

We monitor our long-lived assets recorded in property, plant and equipment in our consolidated balance sheet to insure that they are fairly presented. We must evaluate each property 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 gas sales prices, an estimate of the ultimate amount of recoverable oil and natural gas reserves that will be produced, the timing of future production, future production costs, and future inflation. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or gas, unfavorable adjustment to reserves, or other changes to contracts, environmental regulations, or tax laws. All of these factors must be considered when testing a property's carrying value for impairment. We cannot predict whether impairment charges may be required in the future.

Derivatives

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

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

Asset Retirement Obligations

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

Asset retirement obligations are not unique to us or to the oil and gas industry and in 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," or SFAS 143. We adopted this statement effective January 1, 2003, as discussed in Note 3 to our consolidated financial statements. SFAS 143 significantly changed the method of accruing for costs an entity is legally obligated to incur related to the retirement of fixed assets, or asset retirement obligations or ARO. Primarily, the new statement requires us to record a separate liability for the fair value of our asset retirement obligations, with an offsetting increase to the related oil and gas properties on our consolidated balance sheet.

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

Deferred Taxes

We are subject to income and other taxes in all areas in which we operate. When recording income tax expense, certain estimates are required because: (a) income tax returns are generally filed months after the close of a calendar year; (b) tax returns are subject to audit which 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. We have deferred tax assets relating to tax operating loss carry forwards and other deductible differences. We routinely evaluate our deferred tax assets to determine the likelihood of their realization. A valuation allowance is recognized for deferred tax assets when we believe that certain of these assets are not likely to be realized.

We may be challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in our various income tax returns. Although we believe that we have adequately provided for all taxes, gains or losses could occur in the future year due to changes in estimates or resolution of outstanding tax matters. Currently, none of our consolidated tax returns is under audit or review by the IRS.

Contingent Liabilities

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

Bad Debt Expense

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

Revenues

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

Other

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

Liquidity and Capital Resources

During the three months ended March 31, 2005, we spent $53.1 million on development, exploration and acquisitions while total debt decreased $10.9 million. At March 31, 2005, we had $19.0 million in cash, total assets of $1.6 billion and a debt-to-capitalization ratio of 53%. Available borrowing capacity at March 31, 2005 was $312.1 million under the bank credit facility. Long-term debt at March 31, 2005 totaled $609.6 million, including $262.9 million of bank credit facility debt, $196.7 million of 7-3/8% Notes and $150.0 million of 6-3/8% Notes. In March 2005, we issued $150.0 million of 6-3/8% Notes to better match the maturities of our asset base and lower interest rate volatility. On April 15, 2005, the bank credit facility borrowing base was redetermined and was increased to $600.0 million.

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

The debt agreements contain covenants relating to working capital, dividends and financial ratios. We were in compliance with all covenants at March 31, 2005. Under the bank credit facility, common and preferred dividends are permitted, subject to the terms of the restricted payment basket. The bank credit facility provides for a restricted payment basket of $20.0 million plus 50% of net income plus 66-2/3% of net cash proceeds from common stock issuances occurring since December 31, 2001. Approximately $258.7 million was available under the bank credit facility's restricted payment basket on March 31, 2005. The terms of the 6-3/8% Notes and the 7-3/8% Notes limit restricted payments (including dividends) to the greater of $20.0 million or a formula based on earnings since the issuance of the notes and 100% of net cash proceeds from common stock issuances. Approximately $277.3 million was available under both the 6-3/8% Notes and the 7-3/8% Notes restricted payment basket on March 31, 2005.

The following summarizes our contractual obligations as of March 31, 2005 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities and refinancing proceeds (in thousands):

	Payment Due By Period				
	Remainder of 2005	2006 and 2007	2008 and 2009	Thereafter	Total
Long-term debt	$ —	$ —	$ 262,900(a)	$ 350,000	$ 612,900
Interest on 7.375% notes	7,375	29,500	29,500	59,000	125,375
Interest on 6.375% notes	5,366	19,126	19,126	52,596	96,214
Capital leases	8	5	—	—	13
Operating leases	2,059	2,394	388	—	4,841
Derivative obligations (b)	(101,760)	(43,906)	—	—	(145,666)
Asset retirement obligations	4,924	12,274	6,211	46,324	69,733
Total contractual obligations (c)	$ (82,028)	$ 19,393	$ 318,125	$ 507,920	$ 763,410

(a) Due to the termination date of our bank credit facility, which we expect to renew, but there is no assurance that can be accomplished. As of April 15, 2005, the maturity was extended one year to 2009. Interest paid on the bank credit facility would be approximately $10.8 million each year assuming no change in the interest rate or the outstanding balance.

(b) Derivative obligations represent net open hedging contracts valued as of March 31, 2005.

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

Cash Flow

Our principal sources of cash are operating cash flow and bank borrowings and at times, the sale of assets and the issuance of debt and equity securities. Our operating cash flow is highly dependent on oil and gas prices. As of March 31, 2005, we have entered into hedging swap agreements covering 13.5 Bcf of gas, 0.5 million barrels of oil and 0.2 million barrels of NGLs. We also have collars covering 37.9 Bcf of gas and 3.0 million barrels of oil. Net cash provided by operations for the three months ended March 31, 2005 and 2004 was $65.3 million and $32.2 million, respectively. Cash flow from operations was higher than the prior-year due to higher prices and volumes, partially offset by higher direct operating and production tax expenses. Net cash used in investing for the three months ended March 31, 2005 and 2004 was $48.8 million and $23.2 million, respectively. The 2005 period included $45.1 million of additions to oil and gas properties which was funded with internal cash flow. The 2004 period included $22.8 million of additions to oil and gas properties. Net cash used in financing for the three months ended March 31, 2005 and 2004 was $15.9 million and $8.7 million, respectively. This increase was primarily the result of an increase in dividends and debt issuance costs. During the first three months of 2005, total debt decreased $10.9 million due to internal cash flow.

Dividends

On March 1, 2005, the Board of Directors declared a dividend of two cents per share ($1.6 million) on our common stock, payable on March 31, 2005 to stockholders of record at the close of business on March 15, 2005.

Capital Requirements

The 2005 capital budget is currently set at $254.0 million (excluding acquisitions) and based on current projections, the capital budget is expected to be funded with internal cash flow. During the three months ended March 31, 2005, $49.5 million of development and exploration spending was funded with internal cash flow.

Banking

We maintain a $600.0 million revolving bank credit facility. The facility is secured by substantially all the borrowers' assets. Availability under the facilities is subject to a borrowing base set by the banks semi-annually and in certain other circumstances more frequently. Redeterminations, other than increases, require the approval of 75% of the lenders while increases require unanimous approval. At April 25, 2005, the bank credit facility had a $600.0 million borrowing base of which $317.1 million was available.

Table of Contents

Hedging – Oil and Gas Prices

We enter into hedging agreements to reduce the impact of oil and gas price volatility on our operations. At March 31, 2005, swaps were in place covering 13.5 Bcf of gas at prices averaging $4.22 per Mmbtu, 0.5 million barrels of oil at prices averaging $29.42 per barrel and 0.2 million barrels of NGLs at prices averaging $19.20 per barrel. We also have collars covering 37.9 Bcf of gas at weighted average floor and cap prices of $5.14 to $8.34 per mcf and 3.0 million barrels of oil at prices of $29.84 to $43.63 per barrel. Their fair value at March 31, 2005 (the estimated amount that would be realized on termination based on contract price and a reference price, generally NYMEX) was a net unrealized pre-tax loss of $146.5 million. 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. An ineffective portion (changes in contract prices that do not match changes in the hedge price) of open hedge contracts is recognized in earnings quarterly in other revenue. Net decreases to oil and gas revenues from realized hedging were $20.9 million and $16.7 million for the three months ended March 31, 2005 and 2004, respectively.

At March 31, 2005, the following commodity derivative contracts were outstanding:

Contract Type	Period	Volume Hedged	Average Hedge Price	
Natural gas				
Swaps	April-December 2005	44,841 MMBtu/day	$	4.16
Swaps	2006	3,288 MMBtu/day	$	4.85
Collars	April-December 2005	69,505 MMBtu/day	$	5.14-$7.09
Collars	2006	51,363 MMBtu/day	$	5.26-$8.34
Crude oil				
Swaps	April-December 2005	1,145 Bbl/day	$	26.84
Swaps	2006	400 Bbl/day	$	35.00
Collars	April-December 2005	4,415 Bbl/day	$	29.84-$37.05
Collars	2006	4,864 Bbl/day	$	35.22-$43.63
Natural gas liquids				
Swaps	April-December 2005	654 Bbl/day	$	19.20

Interest Rates

At March 31, 2005, we had $609.6 million of debt outstanding. Of this amount, $346.7 million bore interest at fixed rates averaging 6.9%. Bank debt totaling $262.9 million bears interest at floating rates, which average 4.1% at March 31, 2005. At times, we enter into interest rate swap agreements to limit the impact of interest rate fluctuations on our floating rate debt. At March 31, 2005, we had interest rate swap agreements totaling $45.0 million. These swaps consist of one agreement for $10.0 million at 1.4% which expires in June 2005 and two agreements totaling $35.0 million at 1.8% which expire in June 2006. The fair value of the swaps, based on then current quotes for equivalent agreements at March 31, 2005 was a net gain of $851,000. The 30 day LIBOR rate on March 31, 2005 was 2.9%.

Inflation and Changes in Prices

Our revenues, the value of our assets, our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in oil and gas prices. Oil and gas prices are subject to significant fluctuations that are beyond our ability to control or predict. During the first three months of 2005, we received an average of $47.09 per barrel of oil and $5.97 per mcf of gas before hedging compared to $32.15 per barrel of oil and $5.21 per mcf of gas in the same period of the prior year. Although certain of our costs and expenses are affected by general inflation, inflation does not normally have a significant effect on us. During 2004, we experienced an overall increase in drilling and operational costs when compared to the prior year. Increases in commodity prices can cause inflationary pressures specific to the industry to also increase certain costs. We expect an increase in these costs during the next twelve months.

Table of Contents

Results of Operations

Volumes and sales data:

	Three Months Ended March 31, 2005	Three Months Ended March 31, 2004
Production:		
Crude oil (bbls)	711,083	546,786
NGLs (bbls)	248,943	231,075
Natural gas (mcfs)	14,834,266	11,476,455
Total (mcfe)	20,594,422	16,143,618
Average daily production:		
Crude oil (bbls)	7,901	6,009
NGLs (bbls)	2,766	2,539
Natural gas (mcfs)	164,825	126,115
Total (mcfe)	228,827	177,422
Average sales prices (excluding hedging):		
Crude oil (per bbl)	$ 47.09	$ 32.15
NGLs (per bbl)	$ 25.62	$ 21.29
Natural gas (per mcf)	$ 5.97	$ 5.21
Total (per mcfe)	$ 6.24	$ 5.10
Average sales price (including hedging):		
Crude oil (per bbl)	$ 36.23	$ 24.38
NGLs (per bbl)	$ 22.45	$ 18.99
Natural gas (per mcf)	$ 5.13	$ 4.15
Total (per mcfe)	$ 5.22	$ 4.05

The following table identifies certain items included in our results of operations and is presented to assist in comparing the first quarter of 2005 to the same period of the prior year. The table should be read in conjunction with the following discussion of results of operations (in thousands):

	Three Months Ended March 31, 2005	Three Months Ended March 31, 2004
Increase (decrease) in revenues:		
Ineffective portion of commodity hedges gain (loss)	$ 125	$ (1,554)
Gain (loss) from sales of assets	(9)	(1)
Realized hedging gains (losses)	(20,936)	(16,896)
	$ (20,820)	$ (18,451)
Increase (decrease) to expenses:		
Mark-to-market deferred compensation adjustment	$ 4,064	$ 4,385
Bad debt expense accrual	—	—
Net adjustment to IPF valuation allowance	225	529
Ineffective interest rate swaps	(183)	(799)
	$ 4,106	$ 4,115

Comparison of 2005 to 2004

Overview

For the first quarter of 2005, production averaged 228.8 Mmcfe per day, a 29% increase over the first quarter of 2004 and a 6% increase over the fourth quarter of 2004. The increase is attributable to the impact of the Great Lakes and Pine Mountain acquisitions and the continued success of the drilling program. In addition, our financial performance was positively impacted by 29% higher realized oil and gas prices in the first quarter of 2005 compared to the first quarter of 2004.

Range, and the oil and gas industry as a whole, has experienced increased costs in the exploration, development, and production of oil and gas due to heightened competition for goods and services driven by favorable industry fundamentals. Due primarily to the growth in our production volume attributable to the Great Lakes and Pine Mountain acquisitions, our direct operating expense increased significantly from the first quarter of 2004 to 2005. On a unit cost basis, our direct operating cost increased $0.10 per mcfe (16%) from the first quarter of 2004 to the first quarter of 2005 and $0.07 per mcfe (11%) from the year 2004 to the first quarter of 2005. Cost increases are apparent in all expense categories and it is anticipated that Range, and the oil and gas industry as a whole, will continue to experience upward cost pressure in 2005.

Comparison of Quarter Ended March 31, 2005 and 2004

Net income increased $15.4 million, with higher average oil and gas prices and volumes as a primary factor contributing to this increase. A 70% increase in revenues per mcf was partially offset by higher costs, higher DD&A and higher interest expense.

Average realized price received for oil and gas during the first quarter of 2005 was $5.22 per mcfe, up 29% or $1.17 per mcfe from the same quarter of the prior year. Oil and gas revenues for the first quarter of 2005 reached $107.4 million and were 64% higher than 2004 due to higher oil and gas prices and a 29% increase in production. The average price received increased 49% to $36.23 per barrel for oil and increased 24% to $5.13 per mcf for gas from 2004. The effect of our hedging program decreased realized prices $1.02 per mcfe in the first quarter of 2005 versus a decrease of $1.05 in 2004.

Production volume increased 29% from the first quarter of 2004 primarily due to additions from acquisitions consummated in 2004 which includes our purchase of the 50% of Great Lakes that we did not own and the Pine Mountain acquisition completed late in December 2004. Production increased 4,451 Mmcfe from 2004. Our production for the first quarter was 228,827 mcfe per day and is divided 46% from our Southwestern division, 39% from our Appalachian division and 15% from our Gulf Coast division.

Transportation and gathering revenue of $528,000 increased $61,000 from 2004. This increase is due to additional revenue related to the Great Lakes acquisition offset by lower oil marketing revenues.

Other revenue increased in 2005 to a positive $17,000 from a loss of $2.3 million in 2004. The 2005 period includes $125,000 of ineffective hedging gains and a $110,000 favorable lawsuit settlement offset by $274,000 of net IPF expenses. Other revenue for 2004 includes an ineffective hedging loss of $1.6 million and net IPF expenses of $667,000.

Direct operating expense increased $4.8 million in the first quarter of 2005 to $14.8 million due to increased costs from acquisitions and higher oilfield service costs. Our operating expenses are increasing as we add new wells and maintain production from our existing properties. We incurred $980,000 of expenses associated with workovers in 2005 versus $619,000 in 2004. On a per mcfe basis, direct operating expenses increased $0.10 per mcfe with higher field level costs and higher workover costs.

Production and ad valorem taxes are paid based on market prices and not hedged prices. These taxes increased $1.5 million or 35% from the same period of the prior year due to higher volumes and increasing prices. On a per mcfe basis, production and ad valorem taxes increased to $0.28 per mcfe in 2005 from $0.26 per mcfe in the same period of 2004 due to higher market prices.

Exploration expense decreased 8% to $3.3 million with a lower dry hole costs ($731,000) partially offset by higher personnel costs. Exploration expense includes exploration personnel costs of $1.4 million in 2005 versus $946,000 in 2004.

General and administrative expense for the first quarter of 2005 increased 21% or $1.8 million from 2004 due to higher professional fees ($200,000), higher personnel costs and additional costs related to the Great Lakes and Pine Mountain acquisitions ($1.1 million). On a per mcfe basis, excluding the mark-to-market on the deferred compensation plan, general and administration expense increased from $0.27 per mcfe in 2004 to $0.32 per mcfe in 2005.

Interest expense for 2005 increased $4.4 million to $8.6 million with higher interest rates and higher average debt balances. In connection with the Great Lakes acquisition in mid-2004, we issued an additional $100.0 million of our 7-3/8% Notes which added an additional $1.8 million to interest expense. In addition, in March 2005 we issued $150.0 million of 6-3/8% Notes which added $584,000 of interest costs. The proceeds from the issuance of the 6-3/8% Notes were used to pay down the bank credit facility. Average debt outstanding on the bank credit facility was $398.4 million and $182.3 million for the first quarter of 2005 and 2004, respectively and the average interest rates were 4.1% and 3.1%, respectively.

Depletion, depreciation and amortization, or DD&A, increased $7.5 million or 34% to $29.8 million due to higher production, higher depreciation ($700,000) and higher depletion rates. On a per mcfe basis, DD&A increased from $1.38 per mcfe in the first quarter of 2004 to $1.45 per mcfe.

Tax expense for 2005 increased $9.2 million to $13.1 million reflecting the 234% increase in income before taxes. Both periods provide for a tax expense at 37%.

The following table presents information about our operating expenses per mcfe for the first quarter of 2005 and 2004:

	Three Months Ended March 31,		
	2005	2004	Change
Direct operating expense	$ 0.72	$ 0.62	$ 0.10
Production and ad valorem tax expense	0.28	0.26	0.02
General and administration expense (excluding non-cash mark-to-market on deferred compensation plan)	0.32	0.27	0.05
Interest expense	0.42	0.26	0.16
Depletion, depreciation and amortization expense	1.45	1.38	0.07

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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

We periodically enter into hedging arrangements with respect to our oil and gas production. Hedging is intended to reduce the impact of oil and gas price fluctuations. Certain of our hedges are swaps where we receive a fixed price for our production and pay market prices to the counterparty. In 2003, our hedging program was modified to include collars which assume a minimum floor price and a predetermined ceiling price. In times of increasing price volatility, we may experience losses from our hedging arrangements and increased basis differentials at the delivery points where we market our production. Widening basis differentials occur when the physical delivery market prices do not increase proportionately to the increased prices in the financial trading markets. Realized gains or losses are generally recognized in oil and gas revenue when the associated production occurs. Gains or losses on open contracts are recorded either in current period income or OCI. Generally, derivative losses occur when market prices increase, which are offset by gains on the underlying commodity transaction. Conversely, derivative gains occur when market prices decrease, which are offset by losses on the underlying commodity transaction. Ineffective gains and losses are recognized in earnings in other revenues. Of the $146.5 million unrealized pre-tax loss included in OCI at March 31, 2005, $116.0 million of losses would be reclassified to earnings over the next twelve month period if prices remained constant. The actual amounts that will be reclassified will vary as a result of changes in prices. We do not enter into derivative instruments for trading purposes.

As of March 31, 2005, we had oil and gas swap hedges in place covering 13.5 Bcf of gas, 0.5 million barrels of oil and 0.2 million barrels of NGLs at prices averaging $4.22 per Mmbtu, $29.42 per barrel and $19.20 per barrel, respectively. We also had collars covering 37.9 Bcf of gas at weighted average floor and cap prices of $5.14 and $8.34 per mcf and 3.0 million barrels of oil at weighted average floor and cap prices of $29.84 to $43.63 per barrel. Their fair value, represented by the estimated amount that would be realized on termination, based on contract versus NYMEX prices, approximated a net unrealized pre-tax loss of $146.5 million at that date. These contracts expire monthly through December 2006. 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. Net realized losses relating to these derivatives for the three months ended March 31, 2005 and 2004 were $20.9 million and $16.9 million, respectively.

In the first three months of 2005, a 10% reduction in oil and gas prices, excluding amounts fixed through hedging transactions, would have reduced revenue by $12.8 million. If oil and gas future prices at March 31, 2005 declined 10%, the unrealized hedging loss at that date would have decreased $49.3 million.

Interest rate risk. At March 31, 2005, we had $609.6 million of debt outstanding. Of this amount, $346.7 million bore interest at fixed rates averaging 6.9%. Senior debt totaling $262.9 million bore interest at floating rates averaging 4.1%. At March 31, 2005, we had interest rate swap agreements totaling $45.0 million (see Note 7), which had a fair value gain of $851,000 at that date. A 1% increase or decrease in short-term interest rates would affect interest expense by approximately $2.2 million.

Item 4. CONTROLS AND PROCEDURES

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined in 13a 15(e) of the Securities Exchange Act of 1934 or the Exchange Act). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective in timely alerting us to material information required to be included in this report. Other than the complete integration of Pine Mountain’s financial reporting processes into Range’s processes, there were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal control over financial reporting. As of December 31, 2004, we excluded from our assessment of effectiveness of internal control over financial reporting a material business acquired in December 2004, Pine Mountain. As of March 31, 2005, we have absorbed and integrated all critical accounting functions and conformed the Pine Mountain controls and procedures into those of Range which were included in our assessment at December 31, 2004.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Table of Contents

Item 6. Exhibits and Reports on Form 8-K

(a) EXHIBITS

Exhibit Number	Description
2.1	Purchase and Sale Agreement dated June 1, 2004 between Range and FirstEnergy Corporation (incorporated by reference to Exhibit 2.1 our Form 8-K/A (File No. 001-12209) as filed with the SEC on July 15, 2004)
2.2	Stock Purchase Agreement dated November 22, 2004 between Range and First Reserve Fund IX, L.P., Donald E. Vandenberg, Richard M. Brillhart, Jeremy H. Grantham, Charles Ian Larendon (incorporated by reference to Exhibit 2.1 to our Form 8-K/A (File No. 001-12209) as filed with the SEC on January 27, 2005)
3.1	Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on May 5, 2004)
3.2	Amended and Restated By-laws of Range (incorporated by reference to Exhibit 3.2 to our Form 10-K (File No. 001-12209) as filed with the SEC on March 3, 2004)
4.1	Form of 7.375% Senior Subordinated Notes due 2013 (contained as Exhibit 4.2 hereto)
4.2	Indenture dated July 21, 2003 by and among Range, as issuer, the Subsidiary Guarantors (as defined herein), as guarantors, and Bank One, National Association, as trustee (incorporated by reference to Exhibit 4.4.2 to our Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
4.3	Form of 6.375% Senior Subordinated Notes due 2015 (contained as Exhibit 4.4 hereto)
4.4	Indenture dated March 9, 2005 by and among Range, as issuer, the Subsidiary Guarantors (as defined herein), as guarantors, and JPMorgan Trust Company, National Association, as Trustee (incorporated by reference to Exhibit 4.1 our Form 8-K (File No. 001-12209) as filed with the SEC on January 15, 2005)
4.5	Registration Rights Agreement dated March 9, 2005 by and among Range, and the Initial Purchasers of the 6-3/8% Senior Subordinated Notes due 2015 (as defined therein) (incorporated by reference to Exhibit 4.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on March 15, 2005)
10.1	Range Resources Corporation Executive Change in Control Severance Benefit Plan (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on March 31, 2005)
10.2	Form of Executive Change in Control Severance Agreement (attached as an exhibit to Exhibit 10.1 hereto) (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on March 31, 2005)
10.3	Indenture, dated as of March 9, 2005, between Range Resources Corporation, the Subsidiary Guarantors and JPMorgan Trust Company, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on March 15, 2005)
10.4	Registration Rights Agreement, dated as of March 9, 2005, between Range Resources Corporation and the Initial Purchasers of the 6-3/8% Senior Subordinated Notes due 2015 named therein (incorporated by reference to Exhibit 4.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on March 15, 2005)
10.5	Second Amendment to Second Amended and Restated Credit Facility, effective as of March 2, 2005 (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on March 8, 2005)
10.6	Amended and Restated 1999 Stock Option Plan (incorporated by reference to Exhibit 4.1 to the Company's Form S-8 filed with the Securities and Exchange Commission on June 6, 2003, File No. 333-105895)
10.7	Fourth Amendment to the Amended and Restated 1999 Stock Option Plan (incorporated by reference to Exhibit 4.1 to our Form S-8 filed with the SEC on June 9, 2004, File No. 333-116320)
10.8	Form of Agreement for non-qualified awards pursuant to Amended and Restated 1999 Stock Option Plan, as amended (incorporated by reference to Exhibit 4.3 to our Form 8-K (File No. 001-12209) as filed with the SEC on January 3, 2005)
10.9	Range Resources Corporation Deferred Compensation Plan for Directors and Select Employees (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on January 3, 2005)
31.1*	Certification by the President and Chief Executive Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification by the President and Chief Executive Officer of Range Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification by the Chief Financial Officer of Range Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

RANGE RESOURCES CORPORATION

By: /s/ ROGER S. MANNY

Roger S. Manny
Senior Vice President and Chief Financial Officer
(Principal Financial Officer and duly authorized to sign this report on behalf of the Registrant)

April 27, 2005

Table of Contents

Exhibit index

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4.1	Form of 7.375% Senior Subordinated Notes due 2013 (contained as Exhibit 4.2 hereto)
4.2	Indenture dated July 21, 2003 by and among Range, as issuer, the Subsidiary Guarantors (as defined herein), as guarantors, and Bank One, National Association, as trustee (incorporated by reference to Exhibit 4.4.2 to our Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
4.3	Form of 6.375% Senior Subordinated Notes due 2015 (contained as Exhibit 4.4 hereto)
4.4	Indenture dated March 9, 2005 by and among Range, as issuer, the Subsidiary Guarantors (as defined herein), as guarantors, and JPMorgan Trust Company, National Association, as Trustee (incorporated by reference to Exhibit 4.1 our Form 8-K (File No. 001-12209) as filed with the SEC on January 15, 2005)
4.5	Registration Rights Agreement dated March 9, 2005 by and among Range, and the Initial Purchasers of the 6-3/8% Senior Subordinated Notes due 2015 (as defined therein) (incorporated by reference to Exhibit 4.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on March 15, 2005)
10.1	Range Resources Corporation Executive Change in Control Severance Benefit Plan (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on March 31, 2005)
10.2	Form of Executive Change in Control Severance Agreement (attached as an exhibit to Exhibit 10.1 hereto) (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on March 31, 2005)
10.3	Indenture, dated as of March 9, 2005, between Range Resources Corporation, the Subsidiary Guarantors and JPMorgan Trust Company, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on March 15, 2005)
10.4	Registration Rights Agreement, dated as of March 9, 2005, between Range Resources Corporation and the Initial Purchasers of the 6-3/8% Senior Subordinated Notes due 2015 named therein (incorporated by reference to Exhibit 4.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on March 15, 2005)
10.5	Second Amendment to Second Amended and Restated Credit Facility, effective as of March 2, 2005 (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on March 8, 2005)
10.6	Amended and Restated 1999 Stock Option Plan (incorporated by reference to Exhibit 4.1 to the Company’s Form S-8 filed with the Securities and Exchange Commission on June 6, 2003, File No. 333-105895)
10.7	Fourth Amendment to the Amended and Restated 1999 Stock Option Plan (incorporated by reference to Exhibit 4.1 to our Form S-8 filed with the SEC on June 9, 2004, File No. 333-116320)
10.8	Form of Agreement for non-qualified awards pursuant to Amended and Restated 1999 Stock Option Plan, as amended (incorporated by reference to Exhibit 4.3 to our Form 8-K (File No. 001-12209) as filed with the SEC on January 3, 2005)
10.9	Range Resources Corporation Deferred Compensation Plan for Directors and Select Employees (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on January 3, 2005)
31.1*	Certification by the President and Chief Executive Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification by the President and Chief Executive Officer of Range Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification by the Chief Financial Officer of Range Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* filed herewith

EXHIBIT 31.1

CERTIFICATION

I, John H. Pinkerton, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: April 27, 2005

/s/ JOHN H. PINKERTON

John H. Pinkerton
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Roger S. Manny, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: April 27, 2005

/s/ ROGER S. MANNY

Roger S. Manny
Senior Vice President and Chief Financial Officer

EXHIBIT 32.1

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

In connection with the accompanying report on Form 10-Q for the period ending March 31, 2005 and filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, John H. Pinkerton, President and Chief Executive Officer of Range Resources Corporation (the “Company”), hereby certify that:

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

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

By: /s/ JOHN H. PINKERTON
John H. Pinkerton
April 27, 2005

EXHIBIT 32.2

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

In connection with the accompanying report on Form 10-Q for the period ending March 31, 2005 and filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Roger S. Manny, Chief Financial Officer of Range Resources Corporation (the “Company”), hereby certify that:

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

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

By: /s/ ROGER S. MANNY
Roger S. Manny
April 27, 2005