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 September 30, 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 001-12209

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No ☑

86,475,950 Common Shares were outstanding on October 24, 2005.

RANGE RESOURCES CORPORATION
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PART I – FINANCIAL INFORMATION

RANGE RESOURCES CORPORATION
CONSOLIDATED BALANCE SHEET
(In thousands)

	September 30, 2005 (Unaudited)	December 31, 2004
Assets		
Current assets		
Cash and equivalents	$ 1,388	$ 18,382
Accounts receivable, less allowance for doubtful accounts of $917 and $967	99,953	81,942
Unrealized derivative gain	580	534
Deferred tax asset	96,520	26,310
Inventory and other	14,243	9,168
Total current assets	212,684	136,336
Unrealized derivative gain	—	206
Oil and gas properties, successful efforts method	2,470,632	2,097,026
Accumulated depletion and depreciation	(774,840)	(694,667)
	1,695,792	1,402,359
Transportation and field assets	62,101	59,423
Accumulated depreciation and amortization	(25,053)	(22,141)
	37,048	37,282
Other	24,900	19,223
Total assets	$ 1,970,424	$ 1,595,406
Liabilities		
Current liabilities		
Accounts payable	$ 101,317	$ 78,723
Asset retirement obligation	5,963	6,822
Accrued liabilities	27,227	23,292
Accrued interest	3,729	7,320
Unrealized derivative loss	260,366	61,005
Total current liabilities	398,602	177,162
Bank debt	279,800	423,900
Subordinated notes	346,873	196,656
Deferred taxes, net	141,292	117,713
Unrealized derivative loss	100,800	10,926
Deferred compensation liability	68,334	38,799
Asset retirement obligation	67,067	63,905
Long-term capital lease obligation	—	5
Commitments and contingencies	—	—
Stockholders' equity		
Preferred stock, $1 par, 10,000,000 shares authorized, none issued and outstanding	—	—
Common stock, $.01 par, 250,000,000 shares authorized, 86,528,252 issued at September 30, 2005 and 81,219,351 issued at December 31, 2004	865	812
Common stock held in treasury — 70,837 at September 30, 2005	(1,482)	—
Capital in excess of par value	831,579	707,869
Retained earnings (deficit)	(26,258)	(89,597)
Stock held by employee benefit trust, 1,419,300 and 1,441,751 shares, respectively, at cost	(9,902)	(8,186)
Deferred compensation	(2,350)	(1,257)
Accumulated other comprehensive income (loss)	(224,796)	(43,301)
Total stockholders' equity	567,656	566,340
Total liabilities and stockholders' equity	$ 1,970,424	$ 1,595,406

See accompanying notes

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

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Revenues				
Oil and gas sales	$ 142,055	$ 85,574	$ 368,193	$ 218,495
Transportation and gathering	758	296	1,917	1,107
Other	(968)	344	(621)	(1,159)
	141,845	86,214	369,489	218,443
Expenses				
Direct operating	16,676	12,718	48,903	33,119
Production and ad valorem taxes	8,457	5,331	21,246	14,382
Exploration	7,174	4,615	19,569	12,382
General and administrative	7,183	5,301	20,027	14,789
Non-cash stock compensation	20,118	4,829	29,461	13,517
Interest expense	9,910	6,913	28,041	15,480
Depletion, depreciation and amortization	32,900	26,306	93,098	70,998
	102,418	66,013	260,345	174,667
Income before income taxes	39,427	20,201	109,144	43,776
Income taxes				
Current	331	(132)	331	(88)
Deferred	14,431	7,454	40,484	16,176
	14,762	7,322	40,815	16,088
Net income	24,665	12,879	68,329	27,688
Preferred dividends	—	(737)	—	(2,212)
Net income available to common stockholders	$ 24,665	$ 12,142	$ 68,329	$ 25,476
Earnings per common share:				
Basic	$ 0.29	$ 0.18	$ 0.83	$ 0.42
Diluted	$ 0.28	$ 0.17	$ 0.80	$ 0.40
Dividends per common share	$ 0.02	$ 0.01	$ 0.06	$ 0.02

See accompanying notes.

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RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENT OF CASH FLOWS
(Unaudited, in thousands)

	Nine Months Ended September 30, 2005	2004
Increase (decrease) in cash and equivalents		
Operating activities:		
Net income	$ 68,329	$ 27,688
Adjustments to reconcile net income to net cash provided from operating activities:		
Deferred income tax expense	40,484	16,176
Depletion, depreciation and amortization	93,098	70,998
Unrealized derivative (gains) losses	377	(37)
Allowance for bad debts	675	1,522
Exploration dry hole costs	2,504	4,124
Amortization of deferred issuance costs and discount	1,261	756
Deferred compensation adjustments	30,413	14,057
(Gain) loss on sale of assets and other	157	(990)
Changes in working capital:		
Accounts receivable	(16,954)	241
Inventory and other	(6,879)	(9,335)
Accounts payable	5,535	10,085
Accrued liabilities and other	3,403	7,564
Net cash provided from operating activities	222,403	142,849
Investing activities:		
Additions to oil and gas properties	(197,533)	(106,354)
Additions to field service assets	(7,183)	(2,465)
Acquisitions	(145,341)	(258,508)
IPF net repayments	1,871	5,168
Disposal of assets	3,270	4,821
Net cash used in investing activities	(344,916)	(357,338)
Financing activities:		
Borrowings on credit facilities	217,600	353,800
Repayments on credit facilities	(361,700)	(365,100)
Other debt repayments	(16)	(11,683)
Debt issuance costs	(4,118)	(3,404)
Treasury stock purchases	(2,808)	—
Dividends paid – common stock	(4,990)	(1,828)
– preferred stock	(2,213)	(2,213)
Issuance of subordinated notes	150,000	98,125
Issuance of common stock	113,764	146,662
Net cash provided by financing activities	105,519	214,359
Net decrease in cash and equivalents	(16,994)	(130)
Cash and equivalents at beginning of period	18,382	631
Cash and equivalents at end of period	$ 1,388	$ 501

See accompanying notes.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Net income	$ 24,665	$ 12,879	$ 68,329	$ 27,688
Net deferred hedge gains (losses), net of tax:				
Contract settlements reclassified to income	26,068	15,361	53,325	41,131
Change in unrealized deferred hedging losses	(169,344)	(33,725)	(235,462)	(79,546)
Change in unrealized gains (losses) on securities held by deferred compensation plan	539	(13)	642	51
Comprehensive income (loss)	$ (118,072)	$ (5,498)	$ (113,166)	$ (10,676)

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 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 5). 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 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, or 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.

The accompanying consolidated financial statements include the accounts of Range and of 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 5). The statement of operations for the nine months ended September 30, 2004 includes 50% of the revenues and expenses of Great Lakes up to June 23, 2004 while the nine months ended September 30, 2005 includes 100%. Certain reclassifications have been made to the presentation of prior periods to conform to current year presentation.

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 $917,000 and $967,000 at September 30, 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 December 31, 2004 balance sheet included $17.3 million of cash in an escrow account. These funds were received from the sale of oil and gas properties which were held in escrow to be used to purchase similar assets. As of the second quarter of 2005, the escrow proceeds less transaction expenses were applied towards the bank credit facility.

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 a natural gas equivalent basis, or mcfe, at the rate of one barrel equals 6 mcf. The depletion, depreciation and amortization, or DD&A, rates were $1.47 per mcfe and $1.36 per mcfe in the three months ended September 30, 2005 and 2004, respectively and $1.45 per mcfe and $1.37 per mcfe in the nine months ended September 30, 2005 and 2004. Unproved properties had a net book value of $24.6 million and $14.8 million at September 30, 2005 and December 31, 2004, respectively. Unproved properties are reviewed quarterly for impairment and impaired if conditions indicate we will not exploit 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 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 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 transportation and field service 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. 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 September 30, 2005, the receivable balance was $6.3 million, offset by a valuation allowance of $3.6 million resulting in a net receivable balance of $2.7 million. The $2.7 million net receivable is shown on our consolidated balance sheet in other assets ($1.8 million) and accounts receivable ($888,000). 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 third quarter of 2005, IPF net expense (included in other revenues) included revenues of $10,000 offset by $19,000 of administrative expenses and a $225,000 increase in the valuation allowance. During the same period of the prior year, revenues of $1,300 were offset by $194,000 of administrative expenses, and a $200,000 increase in the valuation allowance. Since 2001, IPF has not acquired new royalties and 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 September 30, 2005 and December 31, 2004, these capitalized costs totaled $8.2 million and $5.7 million, respectively. At September 30, 2005, other assets included $8.2 million of unamortized debt issuance costs, $701,000 of long-term deposits, $14.2 million of marketable securities held in our deferred compensation plans and $1.8 million of long-term IPF receivables. At December 31, 2004, other assets included $5.7 million unamortized debt issuance costs, $9.9 million of marketable securities held in our deferred compensation plans and $3.1 million of IPF long-term receivables.

Gas Imbalances

We use the sales method to account for gas imbalances, recognizing revenue based on gas delivered rather than our working interest share of the gas produced. A liability is recognized when the imbalance exceeds the estimate of remaining reserves. Gas imbalances at September 30, 2005 and December 31, 2004 were not significant.

Derivative Financial Instruments and Hedging

We use commodity-based derivatives to reduce the volatility associated with oil and gas prices. For derivatives qualifying as hedges of future cash flows, the effective portion of any changes in fair value is recognized as 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 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 $361.2 million unrealized pre-tax hedging loss at September 30, 2005, $260.4 million of losses will be reclassified to earnings over the next 12 months and $100.8 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. These interest rate swaps are not designated as hedges and are marked to market each month as a component of 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.

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 compensation plans because the exercise prices of employee option awards equal 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 month and nine months ended September 30, 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 September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Net income, as reported	$ 24,665	$ 12,879	$ 68,329	$ 27,688
Plus: Total stock-based employee compensation cost included in net income, net of tax	12,885	3,181	19,160	8,856
Deduct: Total stock-based employee compensation, determined under fair value based method, net of tax	(15,503)	(4,211)	(25,753)	(13,554)
Pro forma net income	$ 22,047	$ 11,849	$ 61,736	$ 22,990
Earnings per share:				
Basic-as reported	$ 0.29	$ 0.18	$ 0.83	$ 0.42
Basic-pro forma	$ 0.26	$ 0.16	$ 0.75	$ 0.35
Diluted-as reported	$ 0.28	$ 0.17	$ 0.80	$ 0.40
Diluted-pro forma	$ 0.25	$ 0.15	$ 0.73	$ 0.33

Recent Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board, or FASB, issued FASB Statement No. 123 (revised 2004) “Share-Based Payment,” or SFAS 123(R), which is a revision of FASB Statement No. 123, Accounting for Stock-Based Compensation. SFAS 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 SFAS 123(R) is similar to the approach described in Statement 123. However, SFAS 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 rather than pro forma footnote disclosure.

SFAS 123(R) permits companies to adopt its requirements using either a “modified prospective” method, or a “modified retrospective” method. Under the “modified prospective” method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS 123(R) for all share-based payments granted after that date, and based on the requirements of SFAS 123 for all unvested awards granted prior to the effective date of SFAS 123(R). Under the “modified retrospective” method, the requirements are the same as under the “modified prospective” method, but also permits entities to restate financial statements of previous periods based on pro forma disclosures made in accordance with SFAS 123. We have elected to adopt the provisions of SFAS 123(R) using the modified prospective method on January 1, 2006.

We currently utilize a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options and stock appreciation rights granted. While SFAS 123(R) permits entities to continue to use such a model, the standard also permits the use of a “lattice” binomial model. We have not yet determined which model we will use to measure the fair value of employee stock grants upon adoption of SFAS 123(R).

We have not yet determined the financial statement impact of adopting SFAS 123(R) for periods beyond 2005. On June 30, 2005, the Compensation Committee of the Board of Directors approved the acceleration of certain unvested options. All unvested options with vesting dates between January 1, 2006 and April 1, 2006 were accelerated so they will vest on December 31, 2005, representing an average acceleration of 46 days. There were approximately 1.2 million options held by management and non-management employees affected by the acceleration which was undertaken primarily to reduce future stock-based compensation under SFAS 123(R).

In April 2005, the FASB issued Staff Position No. FAS 19-1, “Accounting for Suspended Well Costs, or the FSP. The FSP amends SFAS No. 19, “Financial Accounting and Reporting by Oil and Gas Producing Companies,” or SFAS 19, to allow continued capitalization of exploratory well costs beyond one year from the completion of drilling under circumstances where the well has found a sufficient quantity of reserves to justify its completion as a producing well and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. The FSP also amends SFAS 19 to require enhanced disclosures of suspended exploratory well costs in the notes to the financial statements for annual and interim periods when there has been a significant change from the previous disclosure. The guidance in the FSP is effective for the first reporting period beginning after April 4, 2005. Accordingly, we adopted the new requirements on July 1, 2005 and have included the required disclosures in footnote 3. The adoption of the FSP did not impact our consolidated financial position or results of operations.

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154, “Accounting Changes and Error Corrections – a replacement of APB Opinion No. 20 and FASB Statements No. 3,” or SFAS 154. SFAS 154 provides guidance on the accounting for a reporting of accounting changes and error corrections. It establishes, unless impracticable, retrospective application as the required method for reporting a change in accounting principle in the absence of explicit transition requirements specific to SFAS 154. The provisions of SFAS 154 shall be effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

(3) SUSPENDED EXPLORATORY WELL COSTS

As of July 1, 2005, we adopted FASB Staff Position FAS 19-1, “Accounting for Suspended Well Costs”, or the FSP. Upon adoption of the FSP, we evaluated all existing capitalized exploratory well costs under the provisions of the FSP. The following table reflects the changes in capitalized exploratory well costs for the nine months ended September 30, 2005 and the twelve months ended December 31, 2004 and 2003 (in thousands):

	September 30, 2005	December 31, 2004	December 31, 2003
Beginning balance at January 1	$ 7,100	$ 2,043	$ 4
Additions to capitalized exploratory well costs pending the determination of proved reserves	20,571	4,535	2,039
Additions due to purchase of Great Lakes	—	2,012	—
Reclassifications to wells, facilities and equipment based on determination of proved reserves	—	(784)	—
Capitalized exploratory well costs charged to expense	(253)	(706)	—
Balance at end of period	27,418	7,100	2,043
Less exploratory well costs that have been capitalized for a period of one year or less	(20,571)	(5,892)	(2,039)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ 6,847	$ 1,208	$ 4

The number of projects that have costs that have been capitalized for a period greater than one year is four, three and none as of September 30, 2005, December 31, 2004 and December 31, 2003, respectively. As of September 30, 2005, of the $6.8 million of capitalized exploratory well costs that have been capitalized for more than one year, $3.1 million is attributable to one well waiting on a pipeline connection (expected to be completed in the fourth quarter) and the three remaining wells have additional exploratory wells in the same prospect area drilling or firmly planned. The $27.4 million of capitalized exploratory well costs at September 30, 2005 was incurred in 2005 ($20.6 million), in 2004 ($5.7 million) and in 2003 ($1.1 million).

(4) ASSET RETIREMENT OBLIGATION

A reconciliation of our liability for plugging and abandonment costs for the nine months ended September 30, 2005 and 2004 is as follows (in thousands):

	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Asset retirement obligation beginning of period	$ 70,727	$ 51,844
Liabilities incurred	3,020	18,360
Liabilities settled	(3,097)	(3,338)
Accretion expense	3,809	3,398
Change in estimate	(1,429)	661
Asset retirement obligation end of period	$ 73,030	$ 70,925

Accretion expense is recognized as a component of depreciation, depletion and amortization.

(5) 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 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, in various transactions, properties for $167.3 million and $316.7 million during the nine months ended September 30, 2005 and 2004, respectively. The purchases include $153.0 and $310.6 million for proved oil and gas reserves, respectively, with the remainder representing unproved acreage. In addition, as part of our Great Lakes acquisition in 2004, we purchased $14.4 million of gas gathering facilities.

In June 2005, we purchased Permian Basin oil and gas properties for $116.7 million through the purchase of Plantation Petroleum Acquisition LLC. As a preliminary allocation of purchase price, we have recorded $138.4 million to oil and gas properties, $630,000 of working capital, $22.3 million deferred tax liability and $119,000 additional asset retirement obligations. The acquisition was partially funded with the proceeds from a public offering of 4.6 million common shares ($109.4 million).

In December 2004, we purchased Appalachia oil and gas properties through the purchase of PMOG Holdings, Inc., or Pine Mountain, for $151.4 million plus $57.2 million for the retirement of 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)	$ 223,402
Allocation of purchase price:	
Working capital	5,251
Oil and gas properties	297,459
Field assets and gathering system assets	1,046
Deferred income taxes, net	(79,860)
Asset retirement obligation and other	(494)
Total	$ 223,402

In June 2004, we purchased the 50% of Great Lakes that we did not previously own for $200.0 million 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 bank credit facility as of the purchase date (See further discussion in footnote 7). 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)	$ 228,824
Allocation of purchase price:	
Working capital	5,062
Oil and gas properties	296,160
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	$ 228,824

The following unaudited pro forma data includes the results of operations of the above Great Lakes and Pine Mountain 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 September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Revenues	$141,845	$93,547	$369,489	$268,139
Income before income taxes	39,427	22,559	109,144	59,042
Net income	24,665	14,364	68,329	37,306
Earnings per share:				
Diluted-as reported	$ 0.28	$ 0.17	$ 0.80	$ 0.40
Diluted-pro forma	$ 0.28	$ 0.17	$ 0.80	$ 0.46

(6) SUPPLEMENTAL CASH FLOW INFORMATION

	Nine Months Ended September 30,	
	2005	2004
	(in thousands)	
Non-cash investing and financing activities:		
Common stock issued under benefit plans	$ 2,431	$ 1,312
Debt assumed in Great Lakes acquisition	—	70,000
Cash used in operating activities included:		
Income taxes paid	$ 208	$ 150
Interest paid	30,421	15,968

(7) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (in thousands) (interest rates at September 30, 2005, excluding the impact of interest rate swaps, is shown parenthetically). No interest expense was capitalized during the three months or the nine months ended September 30, 2005 and 2004, respectively.

	September 30, 2005	December 31, 2004
Bank debt (4.9%)	$ 279,800	$ 423,900
Subordinated debt:		
7-3/8% Senior Subordinated Notes due 2013, net of discount	196,873	196,656
6-3/8% Senior Subordinated Notes due 2015	150,000	—
Total debt	$ 626,673	$ 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 September 30, 2005, the borrowing base was redetermined at $600.0 million. At September 30, 2005, the outstanding balance under the bank credit facility was $279.8 million and there was $320.2 million of borrowing capacity available. In April 2005, the loan maturity was extended one year to January 1, 2009. 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 0.5% 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 1.0% and 1.75% 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 the interest rate swaps, was 4.6% for the three months and 4.3% for the nine months ended September 30, 2005. After the effect of the interest rate swaps (see Note 7), the rate was 4.4% for the three months and 4.1% for the nine months ended September 30, 2005. The weighted average interest rate excluding hedges was 3.0% for both the three months and the nine months ended September 30, 2004. The weighted average interest rate including swaps was 3.1% for the three months and 3.4% for the nine months ended September 30, 2004. A commitment fee is paid on the undrawn balance based on an annual rate of between 0.25% and 0.50%. At September 30, 2005, the commitment fee was 0.25% and the interest rate margin was 1.0%. At October 24, 2005, the interest rate (including applicable margin) was 4.9% excluding interest rate swaps and 4.7% after interest rate swaps.

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. In June 2004, we issued an additional $100.0 million of 7-3/8% Notes; therefore, $200.0 million of the 7-3/8% Notes are currently outstanding. We pay interest on the 7-3/8% Notes semi-annually in January and July of each year. The 7-3/8% Notes mature in July 2013 and are guaranteed by certain of our subsidiaries. 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.

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 our subsidiary guarantors are general, unsecured obligations and are subordinated to our senior debt and will be subordinated to future senior debt that Range and our subsidiary guarantors are permitted to incur under the bank credit facility and the indenture governing the 7-3/8% 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 in March and September of each year. The 6-3/8% Notes mature in March 2015 and are guaranteed by certain of our subsidiaries.

We may redeem the 6-3/8% Notes, in whole or in part, at any time on or after March 15, 2010, at redemption prices from 103.7% of the principal amount as of March 15, 2010 and declining to 100% on March 15, 2013 and thereafter. Prior to March 15, 2008, we may redeem up to 35% of the original aggregate principal amount of the notes at a redemption price of 106.4% 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 6-3/8% Notes at 101% of the principal amount plus accrued and unpaid interest, if any.

Debt Covenants

The debt agreements contain covenants relating to working capital, dividends and financial ratios. We were in compliance with all covenants at September 30, 2005. Under the bank credit facility, 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 $350.5 million was available under the bank credit facility’s restricted payment basket on September 30, 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 September 30, 2005, $408.1 million was available under both the 6-3/8% Notes and the 7-3/8% Notes restricted payments basket.

(8) 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 September 30, 2005 and December 31, 2004 (in thousands):

	September 30, 2005		December 31, 2004	
	Book Value	Fair Value	Book Value	Fair Value
Assets				
Cash and equivalents	$ 1,388	$ 1,388	$ 18,382	$ 18,382
Accounts receivable	99,065	99,065	80,562	80,562
IPF receivables	2,671	2,671	4,508	4,508
Marketable securities	14,166	14,166	9,866	9,866
Interest rate swaps	580	580	740	740
Total	117,870	117,870	114,058	114,058
Liabilities				
Accounts payable	(101,317)	(101,317)	(78,723)	(78,723)
Commodity swaps and collars	(361,166)	(361,166)	(71,931)	(71,931)
Long-term debt (1)	(626,673)	(645,675)	(620,556)	(633,556)
Total	(1,089,156)	(1,108,158)	(771,210)	(784,210)
Net financial instruments	$ (971,286)	$ (990,288)	$ (657,152)	$ (670,152)

(1) Fair value based on quotes received from certain brokerage firms. Quotes as of September 30, 2005 were 107% for the 7-3/8% Notes and 101% for the 6-3/8% Notes.

At September 30, 2005, we had open hedging swap contracts covering 10.8 Bcf of gas at prices averaging $5.68 per mcf, 0.3 million barrels of oil at prices averaging $31.58 per barrel and 0.1 million barrels of NGLs at prices averaging $19.20 per barrel. We also had collars covering 74.6 Bcf of gas at weighted average floor and cap prices (by calendar year) which range from $5.31 to $10.38 per mcf and 4.7 million barrels of oil at prices that range from $29.84 to $61.87 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 September 30, 2005, was a net unrealized pre-tax loss of $361.2 million. The contracts expire monthly through December 2007. 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 $41.4 million and $24.4 million due to realized hedging in the three months ended September 30, 2005 and 2004, respectively. Oil and gas revenues were decreased by $84.6 million and $64.5 million due to realized hedging in the nine months ended September 30, 2005 and 2004, respectively. Other revenues in our consolidated statement of operations include ineffective hedging losses of $665,000 and $507,000 in the three months ended September 30, 2005 and 2004, respectively. Other revenues for the nine months ended September 2005 and 2004 include losses of $417,000 and $1.1 million for ineffective hedging, 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 September 30, 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)
June 30	(22,330)
September 30	(41,377)
Subtotal	(84,643)
Total	$ (184,764)
Open Contracts	
2005	
December 31	$ (100,087)
Subtotal	(100,087)
2006	
March 31	(70,224)
June 30	(45,424)
September 30	(44,631)
December 31	(44,895)
Subtotal	(205,174)
2007	
March 31	(19,524)
June 30	(12,215)
September 30	(12,003)
December 31	(12,163)
Subtotal	(55,905)
Total	$ (361,166)

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 September 30, 2005, we had two interest rate swap agreements with a notional amount of $35.0 million. These swaps consist of agreements totaling $35.0 million at 1.8% which expire in June 2006. The fair value of the swaps at September 30, 2005 was a net unrealized pre-tax gain of $580,000.

The combined fair value of net unrealized losses on oil and gas hedges and net unrealized gain on interest rate swaps totaled $360.6 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 September 30, 2005 (in thousands):

	As of September 30, 2005	
	Assets	Liabilities
Commodity swaps	$ —	$ 77,569(a)
Commodity collars	$ —	$283,597(b)
Interest rate swaps	$580	$ —

(a) $45.4 million, $24.7 million and $7.5 million is expected to be reclassified to income in 2005, 2006 and 2007 respectively, if prices remain constant.

(b) $54.7 million, $180.5 million and $48.4 million is expected to be reclassified to income in 2005, 2006 and 2007 respectively, if prices remain constant.

(9) COMMITMENTS AND CONTINGENCIES

We are involved in various legal actions and claims arising in the ordinary course of business, the most significant of which is *Jack Freeman, et al. v. Great Lakes Energy Partners L.L.C., et al.* This is 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, and 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. During the third quarter of 2005, *Pine Mountain Oil and Gas, Inc. et.al.v. Equitable Production Company, et. al.* was filed in the District Court of Abingdon, West Virginia. Pine Mountain Oil and Gas, Inc., the plaintiff in this case and a wholly-owned subsidiary of Range, alleges breach of contract relating to certain gas gathering agreements. Range believes Equitable Production Company has taken deductions for gathering and transportation in excess of the fees provided by contract. For the nine months ended September 30, 2005, we believe up to $2 million of excessive deductions have been made. However, support for the underlying deductions has not been provided by Equitable to Range in order to conduct its investigation of the charges. We believe the resolution of these proceedings will not have a material adverse effect on the consolidated financial position of Range.

(10) STOCKHOLDERS' EQUITY

We have authorized capital stock of 260 million shares, which includes 250 million shares of common stock and 10 million shares of preferred stock. In September 2003, we issued 1.0 million shares of 5.9% Convertible Preferred Stock, 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 common shares outstanding from January 1, 2004 to September 30, 2005:

	Nine Months Ended September 30, 2005	Twelve Months Ended December 31, 2004
Beginning balance	81,219,351	56,409,791
Public offerings	4,600,000	17,940,000
Stock options exercised	677,918	834,537
Restricted stock grants	61,696	80,900
Deferred compensation plan	14,483	3,671
In lieu of fees and bonuses	17,667	30,459
Contributed to 401(k) plan	—	37,640
Exchanged for preferred	—	5,882,353
Treasury shares repurchased	(133,700)	—
	5,238,064	24,809,560
Ending balance	86,457,415	81,219,351

The Board of Directors has approved of up to $5.0 million of repurchases of common stock based on market conditions and opportunities. During the second quarter of 2005, we bought, in open market purchases, 133,700 shares at an average price of $21.00 which are being held as treasury shares. During the second and third quarters, 62,863 of these treasury shares were used for equity compensation.

(11) EQUITY-BASED AND STOCK PURCHASE PLANS

We have five equity-based stock plans, of which two are active, and a stock purchase plan. Under the active plans, incentive and non-qualified options, stock appreciation rights, restricted stock awards, phantom stock rights and annual cash incentive awards may be issued to directors 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 awards granted in the equity-based plans is summarized below:

	Active	Inactive	Total
Outstanding on December 31, 2004	—	4,582,070	4,582,070
Granted	1,061,600	983,050	2,044,650
Exercised	—	(677,918)	(677,918)
Expired/forfeited	(8,300)	(101,132)	(109,432)
	1,053,300	204,000	1,257,300
Outstanding on September 30, 2005	1,053,300	4,786,070	5,839,370

In May 2005, shareholders approved the 2005 Equity Based Compensation Plan, or the 2005 Plan, under which the number of shares that may be granted is equal to 9.25 million shares less the number of shares granted under the 1999 Plan plus the number of shares that become available from 1999 Plan awards that lapse or terminate. During the three months ended September 30, 2005, 1,005,600 stock appreciation rights, or SAR's were granted to eligible employees at prices ranging from $26.90 to $38.27. We recorded non-cash mark-to-market expense in non-cash stock compensation expense related to these SAR's of $2.7 million in the third quarter of 2005.

In May 2004, shareholders approved the Non-Employee Director Stock Option Plan, or the Director Plan, under which 300,000 stock options may 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. Options granted under the Director Plan are fully vested upon grant and have a term of five years. During the nine months ended September 30, 2005, 56,000 options were granted to directors at an exercise price of $21.71 a share. At September 30, 2005, 56,000 options were outstanding at exercise prices of $21.71 a share.

The three inactive plans include the 1999 Stock Option Plan, the Outside Directors Stock Option Plan and the 1989 Stock Option Plan. At September 30, 2005, 4.8 million options were outstanding under the three inactive plans at exercise prices ranging from $1.94 to $23.28 a share. No further options will be granted under the three inactive plans.

At September 30, 2005, 5.8 million grants were outstanding at exercise prices of $1.94 to $38.27 a share as follows:

Range of Exercise Prices	Average Exercise Price	Active	Inactive	Total
$1.94 - $4.99	$ 3.45	—	458,598	458,598
5.00 - 9.99	5.83	—	1,946,082	1,946,082
10.00 - 14.99	10.54	—	1,157,130	1,157,130
15.00 - 19.99	16.17	—	259,610	259,610
20.00 - 38.27	25.13	1,053,300	964,650	2,017,950
Total		1,053,300	4,786,070	5,839,370

In 1997, shareholders approved a stock purchase plan where up to 1.75 million shares of common stock can be sold to directors, employees and consultants. Under the stock purchase plan, the right to purchase shares may be granted at prices ranging from 50% to 85% of market value. To date, all purchase rights have been granted at 75% of market. At September 30, 2005, there were no rights outstanding to purchase shares and there were 373,000 remaining shares authorized to be granted.

During 2005, we issued 61,700 shares of restricted stock to directors and employees at exercise prices ranging from $21.71 to $38.27 a share. In 2004, we issued 81,000 shares of restricted stock to directors and employees at exercise prices ranging from $11.30 to $16.14 a share. In 2003, we issued 134,000 shares of restricted stock to directors and employees at exercise prices ranging from $6.50 to $7.08 a share. We recorded compensation expense related to these grants which is based upon the market value of the shares on the date of grant of $654,000 and $393,000 in the nine month periods ended September 30, 2005 and 2004, respectively. At September 30, 2005, there was $2.2 million of stock based deferred compensation expense related these restricted stock awards remaining to be recognized over their vesting periods.

(12) DEFERRED COMPENSATION PLAN

In 1996, the Board of Directors adopted a deferred compensation plan, or the Plan. The Plan gives directors, officers and key employees the ability to defer all or a portion of their salaries and bonuses and invests such amounts in Range common stock or makes other investments at the employee's discretion. Great Lakes also had a deferred compensation plan that allowed officers and key 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 December 2004, 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 each of the plans are held in rabbi trusts, 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 non-cash stock compensation expense on our consolidated statement of operations. The assets of the Rabbi Trust, other than Range common stock, are 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 Trusts. The cost of common stock held in the Rabbi Trusts is shown as a reduction to stockholders' equity. Changes in the market value of the marketable securities are reflected in OCI, while changes in the market value of the Range common stock held in the Rabbi Trust is charged or credited to non-cash stock compensation expense each quarter. Based on end of month stock prices of $38.61 and $17.49, we recorded non-cash mark-to-market expense related to deferred compensation of $17.4 million and $4.8 million in the three months ended September 30, 2005 and 2004, respectively and $26.8 million and $13.5 million in the nine months ended September 30, 2005 and 2004, respectively.

(13) 401(k) PLAN

We maintain a 401(k) plan for our employees that permits 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. In 2005, we began matching employee contributions up to 3% of salary in cash. Great Lakes also had a 401(k) Plan which was merged into the Range plan in 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 contributed Range 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 stock based on their personal investment strategy.

(14) INCOME TAXES

The significant components of deferred tax liabilities and assets on September 30, 2005 and December 31, 2004 were as follows (in thousands):

	September 30, 2005	December 31, 2004
Deferred tax assets (liabilities)		
Net unrealized loss in OCI	$ 133,037	$ 25,930
Net operating loss carryover and other	129,862	107,809
Depreciation and depletion	(307,671)	(225,142)
Net deferred tax liability	$ (44,772)	$ (91,403)

At December 31, 2004, we had regular net operating loss, or NOL, carryovers of $225.6 million and alternative minimum tax, or AMT, NOL carryovers of $196.5 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.

(15) 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 September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Numerator:				
Net income	$ 24,665	$ 12,879	$ 68,329	$ 27,688
Preferred dividends	—	(737)	—	(2,212)
Numerator for basic earnings per share	$ 24,665	$ 12,142	$ 68,329	$ 25,476
Numerator for diluted earnings per share	$ 24,665	$ 12,879	$ 68,329	$ 27,688
Denominator:				
Weighted average shares outstanding	86,411	69,340	83,437	61,686
Stock held in the deferred compensation plan and treasury shares	(1,475)	(1,715)	(1,468)	(1,687)
Weighted average shares, basic	84,936	67,625	81,969	59,999
Effect of dilutive securities:				
Weighted average shares outstanding	86,411	69,340	83,437	61,686
Employee stock options and other	2,021	1,448	1,747	1,192
Treasury shares	(79)	—	(45)	—
Common shares assumed for Convertible Preferred	—	5,882	—	5,882
Dilutive potential common shares for diluted earnings per share	88,353	76,670	85,139	68,760
Earnings per common share:				
— Basic	$ 0.29	$ 0.18	$ 0.83	$ 0.42
— Diluted	$ 0.28	$ 0.17	$ 0.80	$ 0.40

Options to purchase 313,000 shares of common stock were outstanding but not included in the computations of diluted net income per share for the three months and the nine months ended September 30, 2004 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.

(16) MAJOR CUSTOMERS

We market our production on a competitive basis. Gas is sold under various types of contracts including month-to-month, one-to-five year contracts or 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 nine months ended September 30, 2005, four customers each accounted for 10% or more of total oil and gas revenues and the combined sales to those four customers accounted for 19%, 11%, 11% 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.

(17) 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):

	September 30, 2005	December 31, 2004
Oil and gas properties:		
Properties subject to depletion	$ 2,445,981	$ 2,082,236
Unproved properties	24,651	14,790
Total	2,470,632	2,097,026
Accumulated depletion	(774,840)	(694,667)
Net	$ 1,695,792	$ 1,402,359

	Nine Months Ended September 30, 2005	Twelve Months Ended December 31, 2004
Costs incurred:		
Acquisitions:		
Acreage purchases	$ 14,269	$ 9,690
Unproved leasehold acquired	—	4,043
Proved oil and gas properties	130,088	522,126
Purchase price adjustment (a)	22,779	79,352
Asset retirement obligations	119	17,524
Gas gathering facilities	—	15,539
Subtotal	167,255	648,274
Development	182,945	144,007
Exploration (b)	40,609	31,830
Gas gathering facilities	6,631	4,778
Subtotal	397,440	828,889
Asset retirement obligations	1,470	3,994
Total	$ 398,910	$ 832,883

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

(b) Includes $19,569 and $21,219 of exploration costs expensed in the nine months ended September 30, 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 ensure 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. As of October 24, 2005 we continued to have 13 Mmcfe per day of production shut-in due to the effects of hurricanes Katrina and Rita. While we don't currently believe there is any material long term damage to the shut-in properties, we cannot yet predict whether impairment charges may be required due to these storms.

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 a 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 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 income tax returns are generally filed months after the close of a calendar year, tax returns are subject to audit which can often take years to complete and settle and 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 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 recognize 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 nine months ended September 30, 2005, our cash provided from operations was $222.4 million and we spent $350.1 million on capital expenditures (including acquisitions). During this period, financing activities provided net cash of $105.5 million. Our financing activity included the sale in March 2005 of $150.0 million of 6-3/8% Notes, which enabled us to better match the maturities of our debt with the life of our properties and decrease our interest rate volatility. In addition, in June 2005, we issued 4.6 million common shares in a public offering for net proceeds of $109.4 million. At September 30, 2005, we had $1.4 million in cash, total assets of $2.0 billion and a debt-to-capitalization ratio of 52.5%. Long-term debt at September 30, 2005 totaled $626.7 million including $279.8 million of bank credit facility debt and $346.9 million of senior subordinated notes. Available borrowing capacity under the bank credit facility at September 30, 2005 was $320.2 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 bank 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 September 30, 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 $350.5 million was available under the bank credit facility's restricted payment basket on September 30, 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 $408.1 million was available under both the 6-3/8% Notes and the 7-3/8% Notes restricted payment basket on September 30, 2005.

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 September 30, 2005, we have entered into hedging swap agreements covering 10.8 Bcf of gas, 0.3 million barrels of oil and 0.1 million barrels of NGLs. We also have collars covering 74.6 Bcf of gas and 4.7 million barrels of oil. Net cash provided by operations for the nine months ended September 30, 2005 and 2004 was $222.4 million and $142.8 million, respectively. Cash flow from operations was higher than the prior year due to higher prices and volumes, partially offset by higher operating expenses. Net cash used in investing for the nine months ended September 30, 2005 and 2004 was $344.9 million and $357.3 million, respectively. The 2005 period includes $197.5 million of additions to oil and gas properties and $145.3 million of acquisitions. The 2004 period included $106.4 million of additions to oil and gas properties and $258.5 million of acquisitions. Net cash provided by financing for the nine months ended September 30, 2005 and 2004 was $105.5 million and $214.4 million, respectively. This decrease was primarily the result of the 2004 issuance of an additional $100.0 million of our 7-3/8% Notes and higher proceeds received in 2004 from equity offerings. In 2004, we sold 12.2 million shares resulting in net proceeds of $142.9 million. In 2005, we sold 4.6 million shares resulting in net proceeds of $109.4 million. During the first nine months of 2005, total debt increased $6.1 million.

Dividends

On September 1, 2005, the Board of Directors declared a dividend of two cents per share ($1.7 million) on our common stock, payable on September 30, 2005 to stockholders of record at the close of business on September 15, 2005.

Capital Requirements

The 2005 capital budget is currently set at $311.0 million (excluding acquisitions) and based on current projections, the capital budget is expected to be funded with internal cash flow. For the nine months ended September 30, 2005, $233.6 million of development and exploration spending was funded primarily with internal cash flow.

Banking

We maintain a $600.0 million revolving bank credit facility. The facility is secured by substantially all our assets. Availability under the facility 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 October 24, 2005, the bank credit facility had a $600.0 million borrowing base of which $300.7 million was available.

Other Contingencies

We are involved in various legal actions and claims arising in the ordinary course of business as described in footnote 9 of the notes to consolidated financial statements. We believe the resolution of these proceedings will not have a material adverse effect on the liquidity or consolidated results of operations or financial position of Range.

Hedging – Oil and Gas Prices

We enter into hedging agreements to reduce the impact of oil and gas price volatility on our operations. At September 30, 2005, swaps were in place covering 10.8 Bcf of gas at prices averaging $5.68 per mcf, 0.3 million barrels of oil at prices averaging $31.58 per barrel and 0.1 million barrels of NGLs at prices averaging $19.20 per barrel. We also have collars covering 74.6 Bcf of gas at weighted average floor and cap prices (by calendar year) which range from $5.31 to $10.38 per mcf and 4.7 million barrels of oil at prices that range from $29.84 to $61.87 per barrel. Their fair value at September 30, 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 $361.2 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 $84.6 million and $64.5 million for the nine months ended September 30, 2005 and 2004, respectively.

At September 30, 2005, the following commodity derivative contracts were outstanding:

Contract Type	Period	Volume Hedged	Average Hedge Price
Natural gas			
Swaps	October-December 2005	44,793 MMBtu/day	$4.19
Swaps	2006	10,788 MMBtu/day	$6.43
Swaps	2007	7,500 MMBtu/day	$6.86
Collars	October-December 2005	69,397 MMBtu/day	$5.31-$7.09
Collars	2006	113,363 MMBtu/day	$6.09-$9.79
Collars	2007	73,500 MMBtu/day	$6.22-$10.38
Crude oil			
Swaps	October-December 2005	1,143 Bbl/day	$26.83
Swaps	2006	400 Bbl/day	$35.00
Collars	October-December 2005	4,414 Bbl/day	$29.84-$37.05
Collars	2006	6,864 Bbl/day	$39.82-$49.05
Collars	2007	4,800 Bbl/day	$51.42-$61.87
Natural gas liquids			
Swaps	October-December 2005	652 Bbl/day	$19.20

Interest Rates

At September 30, 2005, we had $626.7 million of debt outstanding. Of this amount, $350.0 million bore interest at fixed rates averaging 6.9%. Bank debt totaling $279.8 million bears interest at floating rates, which average 4.9% at September 30, 2005. At times, we enter into interest rate swap agreements to limit the impact of interest rate fluctuations on our floating rate debt. At September 30, 2005, we had interest rate swap agreements totaling $35.0 million. These swaps consist of two agreements at 1.8% which expire in June 2006. The fair value of the swaps, based on then current quotes for equivalent agreements at September 30, 2005 was a net gain of $580,000. The 30 day LIBOR rate on September 30, 2005 was 3.9%.

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 third quarter of 2005, we received an average of $59.90 per barrel of oil and $7.88 per mcf of gas before hedging compared to $40.99 per barrel of oil and $5.59 per mcf of gas in the same period of the prior year. During 2004 and 2005, we experienced an overall increase in drilling and operational costs when compared to the prior year. Increases in commodity prices and the increased demand for services can cause inflationary pressures specific to the industry to increase for both services and personnel costs. We expect these costs to continue to increase during the next twelve months. Our operations are not in high demand areas but general price inflation is expected and high demand areas draw service providers away from other areas which results in fewer services being available where we operate.

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Results of Operations

Volumes and sales data:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Production:				
Crude oil (bbls)	795,775	669,306	2,230,299	1,802,165
NGLs (bbls)	252,654	259,838	748,951	729,249
Natural gas (mcfs)	16,165,918	13,710,056	46,364,057	36,771,583
Total (mcfe)	22,456,492	19,284,920	64,239,557	51,960,067
Average daily production:				
Crude oil (bbls)	8,650	7,275	8,170	6,577
NGLs (bbls)	2,746	2,824	2,743	2,661
Natural gas (mcfs)	175,717	149,022	169,832	134,203
Total (mcfe)	244,092	209,619	235,310	189,635
Average sales prices (excluding hedging):				
Crude oil (per bbl)	$ 59.90	$ 40.99	$ 52.21	$ 36.65
NGLs (per bbl)	$ 32.90	$ 22.90	$ 29.08	$ 22.16
Natural gas (per mcf)	$ 7.88	$ 5.59	$ 6.79	$ 5.46
Total (per mcfe)	$ 8.17	$ 5.70	$ 7.05	$ 5.45
Average sales price (including hedging):				
Crude oil (per bbl)	$ 41.77	$ 28.79	$ 38.11	$ 26.91
NGLs (per bbl)	$ 27.97	$ 18.30	$ 25.26	$ 18.98
Natural gas (per mcf)	$ 6.29	$ 4.49	$ 5.70	$ 4.25
Total (per mcfe)	$ 6.33	$ 4.44	$ 5.73	$ 4.21

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Increase (decrease) in revenues:				
Ineffective portion of commodity hedges gain (loss)	$ (665)	$ (507)	$ (417)	$ (1,090)
Gains from sale of assets	209	1,684	226	1,694
Writedown of insurance claim receivable	—	(800)	—	(800)
Net adjustment to IPF valuation allowance	(225)	(240)	(675)	(1,074)
Realized hedging losses	(41,377)	(24,383)	(84,643)	(64,524)
	$ (42,058)	$ (24,246)	$ (85,509)	$ (65,794)
Increase (decrease) to expenses:				
Mark-to-market on stock compensation	$ 20,118	$ 4,829	$ 29,461	$ 13,517
Ineffective interest rate swaps	5	—	(40)	(1,127)
Call premium on 6% Debentures	—	178	—	178
	$ 20,123	$ 5,007	$ 29,421	$ 12,568

Comparison of 2005 to 2004

Overview

Revenues increased 65% and 69% for the third quarter and the first nine months of 2005 over the same periods of 2004. This increase is due to higher production and realized prices. For the third quarter of 2005 and the first nine months of 2005, production increased 16% and 24%, respectively. This production growth is due to acquisitions and to the continued success of our drilling program. Realized oil and gas prices were higher by 42% in the third quarter of 2005 and by 36% in the first nine months of 2005 compared to the same periods of 2004 reflecting higher market prices and the expiration of lower priced oil and gas hedges. However, with hedges still in place, Range did not realize potential revenue of $84.6 million in the nine months of 2005 versus $64.5 million in the same period of 2004.

Higher production volumes and higher oil and gas prices have improved our profit margins. However, Range and the oil and gas industry as a whole continues to experience higher operating costs due to heightened competition for goods and services. While the unusually high level of workover expenses experienced in the second quarter of 2005 were not experienced in the third quarter, direct operating expense has increased significantly from the third quarter of last year. On a unit cost basis, our direct operating costs increased $0.08 per mcfe, a 12% increase from the third quarter of 2004 to the third quarter of 2005. For the nine month period ending September 30, 2005, direct operating unit costs increased from $0.64 per mcfe to $0.76 per mcfe, a 19% increase. Service and personnel cost increases are occurring in all facets of our business as oil and gas industry fundamentals remain favorable and it is anticipated that upward pressure on costs will continue.

Comparison of Quarter Ended September 30, 2005 and 2004

Net income increased $11.8 million to $24.7 million primarily due to higher realized oil and gas prices and higher production volumes. A 65% increase in revenues was partially offset by higher non-cash deferred compensation expense, operating costs, higher exploration expenses, DD&A and interest expense.

Average realized price received for oil and gas during the third quarter of 2005 was $6.33 per mcfe, up 42% or $1.89 per mcfe from the same quarter of the prior year. Oil and gas revenues for the third quarter of 2005 reached $141.8 million and were 66% higher than 2004 due to higher oil and gas prices and a 16% increase in production. The average price received in the third quarter for oil increased 45% to $41.77 per barrel and increased 40% to $6.29 per mcf for gas from the same period of 2004. The effect of our hedging program decreased realized prices $1.84 per mcfe in the third quarter of 2005 versus a decrease of $1.26 per mcfe in the same period of 2004.

Production volumes increased 16% from the third quarter of 2004 primarily due to continued drilling success and to a lesser degree, acquisitions consummated in late 2004 and 2005. Our production for the third quarter was 244.1 Mmcfe per day of which 49% was attributable to our Southwestern division, 39% to our Appalachian division and 12% to our Gulf Coast division.

Transportation and gathering revenue of $758,000 increased $462,000 over 2004. This increase is primarily due to higher gas prices and additional throughput volumes.

Other revenue decreased in 2005 to a loss of $968,000 from a gain of $344,000 in 2004. The 2005 period includes $665,000 of ineffective hedging losses and $234,000 of net IPF expenses. Other revenue for 2004 includes a $1.7 million gain on the sale of non-strategic properties and a $331,000 favorable legal settlement offset by $393,000 of net IPF expenses, $507,000 of ineffective hedging losses and an $800,000 valuation allowance against an insurance claim receivable.

Direct operating expense increased $4.0 million in the third quarter of 2005 to $16.7 million due to acquisitions, higher oilfield service costs and higher than normal workover costs. Our operating expenses are increasing as we add new wells and maintain production from our existing properties. We incurred $1.4 million ($0.06 per mcfe) of workover costs in 2005 versus $592,000 ($0.03 per mcfe) in 2004. The increase in workover costs was primarily attributable to workovers on properties located in the Gulf of Mexico and in Oklahoma. On a per mcfe basis, direct operating expenses increased $0.08 per mcfe from the same period of 2004.

Production and ad valorem taxes are paid based on market prices, not hedged prices. These taxes increased $3.1 million or 59% from the same period of the prior year due to higher volumes and increasing prices and assessed values. On a per mcfe basis, production and ad valorem taxes increased to $0.38 per mcfe in 2005 from $0.28 per mcfe in the same period of 2004.

Exploration expense increased 55% to $7.2 million due principally to higher seismic expenditures ($3.4 million) and higher delay rentals somewhat offset by lower dry hole costs ($1.4 million). Exploration expense includes exploration personnel costs of $1.4 million in 2005 versus $1.2 million in 2004.

General and administrative expense for the third quarter of 2005 increased $1.9 million from 2004 due to higher salaries and wages ($711,000) and additional costs as a result of our Pine Mountain acquisition made in late 2004. On a per mcfe basis, general and administration expense increased from $0.27 per mcfe in 2004 to $0.32 per mcfe in 2005.

Non-cash stock compensation for the third quarter of 2005 increased $15.3 million from 2004 primarily due to an increase in the value of Range stock held in the deferred compensation plans. The third quarter of 2005 also includes mark-to-market expense of $2.7 million related to stock appreciation rights issued in the third quarter of 2005.

Interest expense for the third quarter of 2005 increased $3.0 million to $9.9 million due to rising interest rates, higher average debt balances and the refinancing of certain debt from floating to fixed rates. In March 2005, we issued $150.0 million of 6-3/8% Notes which added $2.4 million of interest costs. The proceeds from the issuance of the 6-3/8% Notes were used to retire lower interest bank debt. Average debt outstanding on the bank credit facility was $286.1 million and $319.6 million for the third quarter of 2005 and 2004, respectively and the average interest rates were 4.4% and 3.1%, respectively.

Depletion, depreciation and amortization, or DD&A, increased $6.6 million or 25% to $32.9 million in the third quarter of 2005 with a 16% increase in production and a 12% increase in depletion rates. On a per mcfe basis, DD&A increased from $1.36 per mcfe in the third quarter of 2004 to $1.47 per mcfe in the third quarter of 2005.

Tax expense for 2005 increased $7.4 million to $14.8 million reflecting the 95% increase in income before taxes. The third quarter 2005 and 2004 provide for a tax expense at an effective rate of approximately 37%. Current income taxes are associated with the state of Virginia where our current level of drilling is not sufficient to offset taxable income.

The following table presents information about our operating expenses per mcfe for the three months ended September 2005 and 2004:

	Three Months Ended September 30,		
	2005	2004	Change
Direct operating expense	$0.74	$0.66	$0.08
Production and ad valorem tax expense	0.38	0.28	0.10
General and administration expense	0.32	0.27	0.05
Interest expense	0.44	0.36	0.08
Depletion, depreciation and amortization expense	1.47	1.36	0.11

Comparison of Nine Months Ended September 30, 2005 and 2004

Net income increased $40.6 million to $68.3 million, with higher realized oil and gas prices and higher production volumes as the primary factors contributing to the increase. A 69% increase in revenues was partially offset by higher non-cash deferred compensation expense, higher operating costs, higher exploration expenses, DD&A and interest expense.

Average realized price received for oil and gas during the first nine months of 2005 was $5.73 per mcfe, up 36% or $1.52 per mcfe from the same period of the prior year. Oil and gas revenues for the first nine months of 2005 reached $368.2 million and were 69% higher than 2004 due to higher oil and gas prices and a 24% increase in production. The average price received in the first nine months of 2005 for oil increased 42% to $38.11 per barrel and rose 34% to $5.70 per mcf for gas from the same period of 2004. The effect of hedging decreased realized prices $1.32 per mcfe in the first nine months of 2005 versus a decrease of $1.24 per mcfe in 2004.

Production volumes increased 24% primarily due to continued drilling success and to additions from acquisitions consummated in the second half 2004. Our production for the first nine months was 235.3 Mmcfe per day with 48% attributable to our Southwestern division, 39% to our Appalachian division and 13% to our Gulf Coast division.

Transportation and gathering revenue of $1.9 million increased $810,000 from 2004. The increase is due to additional revenue related to the Great Lakes acquisition, higher gas prices and higher throughput, partially offset by lower oil marketing revenues.

Other revenue increased in 2005 to a loss of $621,000 from a loss of $1.2 million in 2004. The 2005 period includes $417,000 of ineffective hedging losses and $735,000 of net IPF expenses somewhat offset by a favorable lawsuit settlement ($110,000) and additional revenue related to the Great Lakes acquisition. Other revenue for the first nine months of 2004 includes an ineffective hedging loss of $1.1 million, an $800,000 valuation allowance against an insurance claim receivable and net IPF expenses of $1.6 million offset by a $1.7 million gain on the sale of properties and a $331,000 favorable legal settlement.

Direct operating expense increased $15.8 million in the first nine months of 2005 to $48.9 million due to increased costs from acquisitions, higher oilfield service costs and higher than normal workovers. Our operating expenses are increasing as we add new wells and maintain production from our existing properties. We incurred $5.1 million ($0.08 per mcfe) of workover related expenses in 2005 versus $1.5 million ($0.03 per mcfe) in the same period of 2004. On a per mcfe basis, direct operating expenses increased $0.12 per mcfe from the same period of 2004.

Production and ad valorem taxes are paid based on market prices and not hedged prices. These taxes increased $6.9 million or 48% from the same period of the prior year due to higher volumes and increasing prices and assessed values. On a per mcfe basis, production and ad valorem taxes increased to $0.33 per mcfe in 2005 from $0.28 per mcfe in the same period of 2004.

Exploration expense increased 58% to $19.6 million with a lower dry hole costs ($3.1 million) more than offset by higher seismic costs ($8.3 million), higher personnel costs ($1.0 million) and higher delay rentals ($849,000). Exploration expense includes exploration personnel costs of $4.2 million in the first nine months of 2005 versus $3.2 million in the same period of 2004.

General and administrative expense for the first nine months of 2005 increased to $20.1 million due to higher personnel costs related to the Great Lakes and Pine Mountain acquisitions ($1.7 million) and higher personnel costs not related to acquisitions ($2.2 million). On a per mcfe basis, general and administration expense increased from $0.28 per mcfe in the first nine months of 2004 to $0.31 per mcfe in the first nine months of 2005.

Non-cash stock compensation expense for the first nine months of 2005 increased to $29.5 million primarily due to an increase in the value of Range stock held in the deferred compensation plans. The nine months of 2005 also includes mark-to-market expense of $2.7 million related to stock appreciation rights issued in the third quarter of 2005.

Interest expense for the first nine months of 2005 increased $12.6 million to $28.0 million with rising interest rates, higher average debt balances and the refinancing of certain debt from floating to fixed rates. 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 $3.6 million to interest expense. Also, in March 2005 we issued $150.0 million of 6-3/8% Notes which added $5.4 million of interest costs. The proceeds from the issuance of the 6-3/8% Notes were used to retire lower interest bank debt. Average debt outstanding on the bank credit facility was $319.2 million and $276.6 million for the first nine months of 2005 and 2004, respectively and the average interest rates were 4.1% and 3.4%, respectively.

Depletion, depreciation and amortization, or DD&A, increased $22.1 million or 31% to $93.1 million with a 24% increase in production, a 8% increase in depletion rates, higher depreciation expense ($1.6 million) partially offset by lower unproved property amortization ($1.2 million). On a per mcfe basis, DD&A increased from $1.37 per mcfe in the first nine months of 2004 to $1.45 per mcfe in the same period of 2005.

Tax expense for 2005 increased $24.7 million to $40.8 million reflecting the 149% increase in income before taxes. Each of the nine month periods provide for a tax expense at an effective rate of approximately 37%. Current income taxes are associated with the state of Virginia where our current level of drilling is not sufficient to offset taxable income.

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

	Nine Months Ended September 30,		
	2005	2004	Change
Direct operating expense	$0.76	$0.64	$0.12
Production and ad valorem tax expense	0.33	0.28	0.05
General and administration expense	0.31	0.28	0.03
Interest expense	0.44	0.30	0.14
Depletion, depreciation and amortization expense	1.45	1.37	0.08

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 extremely 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. A portion 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 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 $361.2 million unrealized pre-tax loss included in OCI at September 30, 2005, $260.4 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 September 30, 2005, we had oil and gas swap hedges in place covering 10.8 Bcf of gas, 0.3 million barrels of oil and 0.1 million barrels of NGLs at prices averaging $5.68 per mcf, $31.58 per barrel and $19.20 per barrel, respectively. We also had collars covering 74.6 Bcf of gas at weighted average floor and cap prices (by calendar year) which range from $5.31 to $10.38 per mcf and 4.7 million barrels of oil at prices that range from $29.84 to $61.87 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 $361.2 million at that date. These contracts expire monthly through December 2007. 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 September 30, 2005 and 2004 were $41.4 million and $24.4 million, respectively. Net realized losses relating to these derivatives for the nine months ended September 30, 2005 and 2004 were $84.6 million and $64.5 million, respectively.

In the first nine months of 2005, a 10% reduction in oil and gas prices, excluding amounts fixed through hedging transactions, would have reduced revenue by $45.3 million. If oil and gas future prices at September 30, 2005 declined 10%, the unrealized hedging loss at that date would have decreased by $122.9 million.

Interest rate risk. At September 30, 2005, we had $626.7 million of debt outstanding. Of this amount, $350.0 million bore interest at fixed rates averaging 6.9%. Senior debt totaling $279.8 million bore interest at floating rates averaging 4.9%. At September 30, 2005, we had interest rate swap agreements totaling $35.0 million (see Note 7), which had a fair value gain of $580,000 at that date. A 1% increase or decrease in short-term interest rates would affect interest expense by approximately $2.4 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. 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.

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PART II. OTHER INFORMATION

Item 6. Exhibits

(a) EXHIBITS

Exhibit Number	Description
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, as amended by the Certificate of First Amendment to Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 28, 2005)
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)
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)

October 26, 2005

Exhibit index

Exhibit Number	Description
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* 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: October 26, 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: October 26, 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 September 30, 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
October 26, 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 September 30, 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
October 26, 2005