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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

[X] Quarterly Report Pursuant to Section 13 or 15(d) of
the Securities Exchange Act of 1934
For the period ended September 30, 2005

OR

[ ] Transition Report Pursuant to Section 13 of 15(d) of
the Securities Exchange Act of 1934
For the transition period from ____ to

Commission file number 0-7246

I.R.S. Employer Identification Number 95-2636730

PETROLEUM DEVELOPMENT CORPORATION
(A Nevada Corporation)
103 East Main Street
Bridgeport, WV 26330
Telephone: (304) 842-6256

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 XX

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 16,272,028 shares of the Company's Common Stock ($.01 par value) were outstanding as of November 30, 2005.

Indicate by check mark whether the registrant is an accelerated filer (as definition in Rule 12b-2 of the Exchange Act). Yes XX No __

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

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Explanatory Note – 2005 Restatement

As described in our Amended Annual Report on Form 10-K/A for the year ended December 31, 2004 and our Amended Quarterly Report on Form 10-Q/A for the three months ended March 31, 2005, we restated certain financial statements and other information, including such statements and information for each of the quarters of 2004 and the quarter ended March 31, 2005. These restatements related to our accounting for derivative transactions, certain aspects of the Company's oil and gas property accounting, asset retirement obligations and accounting for income taxes.

PART I - FINANCIAL INFORMATION

Report of Independent Registered Public Accounting Firm

The Board of Directors
Petroleum Development Corporation:

We have reviewed the accompanying condensed consolidated balance sheet of Petroleum Development Corporation and subsidiaries as of September 30, 2005, the related condensed consolidated statements of income for the three-month and nine-month periods ended September 30, 2005 and 2004, and the related condensed consolidated statements of cash flows for the nine-month periods ended September 30, 2005 and 2004. These condensed consolidated financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical review procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the condensed consolidated financial statements referred to above for them to be in conformity with U. S. generally accepted accounting principles.

We have previously audited, in accordance with standards of Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Petroleum Development Corporation and subsidiaries as of December 31, 2004, and the related consolidated statements of income, stockholders' equity and cash flows for the year then ended (not presented herein); and in our report dated March 30, 2005, except as to the restatement discussed in Note 22 to the consolidated financial statements which is as of December 2, 2005, we expressed an unqualified opinion on those consolidated financial statements. As discussed in that report, the consolidated financial statements as of December 31, 2004 and 2003, and for each of the years in the three year period ended December 31, 2004 have been restated and the report also included an explanatory paragraph referring to a change in accounting for asset retirement obligations in 2003. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2004 is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

As discussed in notes 21 and 22 to the Company's Form 10-K/A as of December 31, 2004, the Company has restated the condensed consolidated balance sheet as of December 31, 2004 and the condensed consolidated statements of income and cash flows for the three and nine month periods ended September 30, 2004.

KPMG LLP

Pittsburgh, Pennsylvania
January 11, 2006

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES
Condensed Consolidated Balance Sheets
September 30, 2005 and December 31, 2004

ASSETS	2005 (Unaudited)	2004 (Restated)
Current assets:		
Cash and cash equivalents	$ 64,801,600	$ 77,735,300
Accounts and notes receivable	56,143,500	36,065,300
Inventories	7,831,600	1,657,300
Prepaid expenses	25,529,000	9,878,900
Total current assets	154,305,700	125,336,800
Properties and equipment	343,349,100	299,748,700
Less accumulated depreciation, depletion and amortization	105,413,600	92,165,400
	237,935,500	207,583,300
Other assets	4,390,100	2,108,200
	$ 396,631,300	$ 335,028,300

(Continued)

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES
Condensed Consolidated Balance Sheets, Continued
September 30, 2005 and December 31, 2004

LIABILITIES AND STOCKHOLDERS' EQUITY	2005 (Unaudited)	2004 (Restated)
Current liabilities:		
Accounts payable and accrued expenses	$ 115,286,600	$ 69,696,600
Advances for future drilling contracts	24,847,500	42,497,300
Funds held for future distribution	18,933,200	12,911,800
Total current liabilities	159,067,300	125,105,700
Long-term debt	14,000,000	21,000,000
Other liabilities	10,623,500	3,927,500
Deferred income taxes	29,660,200	22,976,300
Asset retirement obligations	8,187,100	7,998,200
Stockholders' equity:		
Common stock par value $0.01 per share; authorized 50,000,000 shares; issued and outstanding 16,272,028 shares and 16,589,824 shares	162,700	165,800
Additional paid-in capital	30,211,400	37,684,300
Retained earnings	145,576,800	117,052,500
Unamortized stock award	(857,700)	(882,000)
Total stockholders' equity	175,093,200	154,020,600
	$ 396,631,300	$ 335,028,300

See accompanying notes to unaudited condensed consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES
Condensed Consolidated Statements of Income
Three Months and Nine Months Ended September 30, 2005 and 2004
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004 (Restated)	2005	2004 (Restated)
Revenues:				
Oil and gas well drilling operations	$ 39,710,600	$ 30,394,400	$ 108,118,300	$ 89,347,500
Gas sales from marketing activities	14,970,300	22,630,200	58,409,400	69,643,400
Oil and gas sales	28,413,400	16,580,500	68,619,900	49,105,700
Well operations and pipeline income	2,483,300	2,073,800	6,840,100	5,823,700
Other income	209,400	589,000	9,996,000	1,334,100
Total revenues	85,787,000	72,267,900	251,983,700	215,254,400
Cost and expenses:				
Cost of oil and gas well drilling operations	36,177,500	26,005,400	95,112,200	76,328,400
Cost of gas marketing activities	14,269,500	22,047,400	58,348,400	68,542,900
Oil and gas production and well operations cost	6,455,400	3,952,400	15,356,700	11,894,500
Exploratory dry hole costs	135,800	-	5,382,800	-
General and administrative expenses	1,645,500	926,300	4,529,000	2,821,400
Depreciation, depletion and amortization	5,120,000	4,312,300	14,822,000	13,308,000
Total expenses	63,803,700	57,243,800	193,551,100	172,895,200
Income from operations	21,983,300	15,024,100	58,432,600	42,359,200
Interest expense	142,200	223,100	433,000	627,100
Oil and gas price risk management loss, net	9,922,300	2,378,800	12,723,000	4,077,500
Income before income taxes	11,918,800	12,422,200	45,276,600	37,654,600
Income taxes	4,413,000	4,506,400	16,752,300	13,596,200
Net income	$ 7,505,800	$ 7,915,800	$ 28,524,300	$ 24,058,400
Basic earnings per common share	$ 0.46	$ 0.49	$ 1.74	$ 1.50
Diluted earnings per share	$ 0.46	$ 0.47	$ 1.73	$ 1.45

See accompanying notes to unaudited condensed consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES
Condensed Consolidated Statements of Cash Flows
Nine Months Ended September 30, 2005 and 2004
(Unaudited)

	2005	2004(a) (Restated)
Cash flows from operating activities:		
Net income	$ 28,524,300	$ 24,058,400
Adjustments to net income to reconcile to cash provided by operating activities:		
Deferred income taxes	6,683,900	7,670,500
Depreciation, depletion and amortization	14,822,000	13,308,000
Unrealized loss on derivative transactions	9,416,200	2,592,900
Accretion of asset retirement obligation	344,500	322,600
Exploratory dry hole costs	5,382,800	-
Gain from sale of assets	(7,869,800)	(5,300)
Leasehold acreage expired or surrendered	12,900	291,000
Amortization of stock award	427,100	2,800
Increase in current assets	(17,360,800)	(3,301,300)
Increase in other assets	(1,205,200)	(161,800)
Increase (decrease) in current liabilities	6,042,800	(15,078,500)
(Decrease) increase in other liabilities	(462,600)	562,000
Total adjustments	16,233,800	6,202,900
Net cash provided by operating activities	44,758,100	30,261,300
Cash flows from investing activities:		
Capital expenditures	(53,968,800)	(26,458,100)
Proceeds from sale of leases to partnerships	1,575,100	1,178,800
Proceeds from sale of fixed assets	9,580,700	68,900
Net cash used in investing activities	(42,813,000)	(25,210,400)
Cash flows from financing activities:		
Net retirement of long-term debt	(7,000,000)	(26,000,000)
Proceeds from stock option exercises	-	2,178,600
Repurchase and cancellation of treasury stock	(7,878,800)	(2,749,100)
Net cash used in financing activities	(14,878,800)	(26,570,500)
Net decrease in cash and cash equivalents	(12,933,700)	(21,519,600)
Cash and cash equivalents, beginning of period	77,735,300	80,379,300
Cash and cash equivalents, end of period	$ 64,801,600	$ 58,859,700

See accompanying notes to unaudited condensed consolidated financial statements.

a. Only certain individual line items within cash provided by operating activities have been restated. Net cash provided by operating activities is the same as the original 10-Q filing.

Notes to Condensed Consolidated Financial Statements
September 30, 2005
(Unaudited)

1. Accounting Policies

Reference is hereby made to Petroleum Development Corporation and Subsidiaries' (the Company) Annual Report on Form 10-K/A for 2004, which contains a summary of significant accounting policies followed by the Company in the preparation of its consolidated financial statements. These policies were also followed in preparing the quarterly report included herein.

As described in our Amended Annual Report on Form 10-K/A for the year ended December 31, 2004 and our Amended Quarterly Report on Form 10-Q/A for the three months ended March 31, 2005, we restated certain financial statements and other information, including such statements and information for each of the quarters of 2004 and the quarter ended March 31, 2005. These restatements related to our accounting for derivative transactions, certain aspects of the Company's oil and gas property accounting, asset retirement obligations and accounting for income taxes.

2. Stock Compensation

The Company applies the intrinsic-value based method of accounting prescribed by Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees", and related interpretations including FASB Interpretation No. 44, "Accounting for Certain Transactions involving Stock Compensation, an interpretation of APB Opinion No. 25", to account for its fixed-plan stock options. Under this method, compensation expense is recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price. FASB Statement No. 123, "Accounting for Stock-Based Compensation" and FASB Statement No. 148, "Accounting for Stock Based Compensation- Transition and Disclosure, an amendment of FASB Statement No. 123", established accounting and disclosure requirements using a fair-value-based method of accounting for stock-based employee compensation plans. As permitted by existing accounting standards, the Company has elected to continue to apply the intrinsic-value-based method of accounting described above, and has adopted only the disclosure requirements of Statement 123, as amended and Statement 148. If the fair-value-based method had been applied to all outstanding and unvested awards in each period, the impact for the nine months of 2005 would have been $71,400. There would have been no impact on reported net income in 2004.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004 (Restated)	2005	2004 (Restated)
Net income, as reported	$ 7,505,800	$ 7,915,800	$ 28,524,300	$ 24,058,400
Stock-based employee compensation expenses included in reported net income, net of related tax effects	106,900	600	269,100	1,800
Deduct total stock-based employee compensation expense determined under fair-value based method for all rewards, net of tax	(130,700)	(600)	(340,500)	(1,800)
Pro forma net income	$ 7,482,000	$ 7,915,800	$ 28,452,900	$ 24,058,400
Basic earnings per share as reported	$ 0.46	$ 0.49	$ 1.74	$ 1.50
Pro forma basic earnings per share	$ 0.46	$ 0.49	$ 1.73	$ 1.50
Diluted earnings per share as reported	$ 0.46	$ 0.47	$ 1.73	$ 1.45
Pro forma diluted earnings per share	$ 0.46	$ 0.47	$ 1.73	$ 1.45

On December 16, 2004, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 123R (revised 2004), "Share-Based Payment" which is a revision of FASB Statement No. 123, "Accounting for Stock-Based Compensation". Statement 123R supersedes APB opinion No. 25, "Accounting for Stock Issued to Employees", and amends FASB Statement No. 95, "Statement of Cash Flows". Generally, the approach in Statement 123R is similar to the approach described in Statement 123. However, Statement 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their fair values. Pro-forma disclosure is no longer an alternative. On April 14, 2005, the SEC amended the effective date of the provisions of this statement. The effect of this amendment by the SEC is that we will have to comply with Statement 123R and use the Fair Value based method of accounting no later than the first quarter of 2006. Management has not determined the impact that this statement will have on our consolidated financial statements.

3. Basis of Presentation

The Management of the Company believes that all adjustments (consisting of only normal recurring accruals) necessary for a fair statement of the results of such periods have been made. The results of operations for the nine months ended September 30, 2005 are not necessarily indicative of the results to be expected for the full year.

4. Oil and Gas Properties

Oil and Gas Properties are reported on the successful efforts method.

5. Earnings Per Share

Computation of earnings per common and common equivalent share are as follows for the three months and nine months ended September 30, 2005 and 2004.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Weighted average common shares outstanding	16,271,593	16,284,827	16,433,859	16,140,358
Weighted average common and common equivalent shares outstanding	16,322,795	16,694,637	16,484,787	16,542,623
		(Restated)		(Restated)
Net income	$ 7,505,800	$ 7,915,800	$ 28,524,300	$ 24,058,400
Basic earnings per share	$ 0.46	$ 0.49	$ 1.74	$ 1.50
Diluted earnings per share	$ 0.46	$ 0.47	$ 1.73	$ 1.45

6. Business Segments (Thousands)

PDC's operating activities can be divided into four major segments: drilling and development, natural gas marketing, oil and gas sales, and well operations and pipeline income. The Company drills natural gas wells for Company-sponsored drilling partnerships and retains an interest in each well. A wholly-owned subsidiary, Riley Natural Gas, engages in the marketing of natural gas to commercial and industrial end-users. The Company owns an interest in over 2,700 wells from which it derives oil and gas working interests. The Company charges Company-sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. All material inter-company accounts and transactions between segments have been eliminated. Segment information for the three and nine months ended September 30, 2005 and 2004 is as follows: (All numbers presented below are in thousands.)

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004 (Restated)	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004 (Restated)
REVENUES				
Drilling and Development	$ 39,710	$ 30,394	$ 108,118	$ 89,347
Natural Gas Marketing	15,030	22,641	58,605	69,669
Oil and Gas Sales	28,414	16,581	68,620	49,106
Well Operations and Pipeline Income	2,483	2,074	6,840	5,824
Unallocated amounts (1)	150	578	9,801	1,308
Total	$ 85,787	$ 72,268	$ 251,984	$ 215,254
SEGMENT INCOME (LOSS) BEFORE INCOME TAXES				
Drilling and Development	$ 3,533	$ 4,389	$ 13,006	$ 13,019
Natural Gas Marketing	759	591	250	1,120
Oil and Gas Sales(3)	9,022	7,136	25,006	23,102
Well Operations and Pipeline Income	393	965	2,626	2,846
Unallocated amounts (2)				
General and Administrative expenses	(1,646)	(926)	(4,529)	(2,821)
Interest expense	(142)	(223)	(433)	(627)
Other (1)	-	490	9,351	1,016
Total	$ 11,919	$ 12,422	$ 45,277	$ 37,655

	September 30, 2005	December 31, 2004 (Restated)
SEGMENT ASSETS		
Drilling and Development	$ 41,366	$ 64,348
Natural Gas Marketing	59,205	31,234
Oil and Gas Sales	258,974	211,255
Well Operations and Pipeline Income	24,553	16,518
Unallocated amounts(2)		
Cash	186	112
Other	12,347	11,561
Total	$ 396,631	$ 335,028

(1) Includes gains on sales of assets, interest on investments and partnership management fees which are not allocated in assessing segment performance.
(2) Items which are not allocated in assessing segment performance.
(3) Includes $5.4 million in exploratory dry hole costs in the nine months ended September 30, 2005.

7. Sale of Undeveloped Acreage

During the first quarter of 2005, the Company sold a portion of one of its undeveloped Garfield County, Colorado leases to an unaffiliated entity. The proceeds of the sale were $6.2 million and the Company's carrying value of the property was zero. The Company was required to remit $1.0 million to the original lessor, unless it commenced construction of certain facilities adjacent to this undeveloped property subject to certain timing conditions. The gain of $5.2 million was recognized during the first quarter of 2005 and is included in "Other Income" in the accompanying condensed consolidated statements of income. During the second quarter of 2005, the Company commenced construction of the facilities and recorded income of $1.0 million which is included in "Other Income" in the accompanying condensed consolidated statements of income.

8. Sale of Producing Wells

During the second quarter of 2005, the Company completed the sale to an unaffiliated entity of 111 Pennsylvania wells it purchased from Pemco Gas, Inc. in 1998. The Company received proceeds of $3.4 million and recorded a gain of approximately $1.7 million which is included in "Other Income" in the accompanying condensed consolidated statements of income.

9. Exploratory Dry Hole

During the second quarter of 2005, the exploratory Fox Federal #1-13 well was deemed to be non-commercial after well tests were completed and will be plugged and abandoned. Under the successful efforts method of accounting, this cost is required to be expensed in the period when such determination is made. This amounted to a $5.0 million expense which is included in the accompanying condensed consolidated statements of income under Exploratory Dry Hole Costs. Due to the dry hole, the Company reevaluated the Company's adjacent leases and wrote off approximately $383,000 which is included in Exploratory Dry Hole Costs.

10. Commitments and Contingencies

The nature of the independent oil and gas industry involves a dependence on outside investor drilling capital and involves a concentration of gas sales to a few customers. The Company sells natural gas to various public utilities, natural gas marketers, industrial and commercial customers.

The Company would be exposed to natural gas price fluctuations on underlying purchase and sale contracts should the counterparties to the Company's derivative instruments not perform. Such nonperformance is not anticipated. There were no counterparty default losses in the first three quarters of 2005 or the year 2004.

Substantially all of the Company's drilling programs contain a repurchase provision where Investors may request the Company to repurchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 month's cash distributions), if investors request the Company to repurchase such units, subject to the Company's financial ability to do so. The maximum annual 10% repurchase obligation, if requested by investors, is currently approximately $8.4 million. The Company believes it has adequate liquidity to meet this obligation should it arise.

The Company's drilling programs formed since 1996 contain a performance standard which states that if certain performance levels are not met, the Company must remit a payment equal to one-half of its share of revenue from such partnership to the investing partners. For the nine months ended September 30, 2005 and 2004, the Company paid partnerships a total of $564,200 and $475,000 respectively in accordance with the provision.

As Managing General Partner of 10 private limited partnerships and 64 public limited partnerships, the Company has liability for any potential casualty losses in excess of the partnership assets and insurance. The Company is the sole general partner of each of these various limited partnerships. The Company believes its casualty insurance coverage is adequate to meet this potential liability.

In order to secure the services for drilling rigs, the Company makes commitments to the drilling contractor which call for penalties for a specified amount of time if the Company ceases to use such drilling rigs, an event that is not anticipated to occur. As of September 30, 2005, the Company has an outstanding commitment for $25.5 million.

From time to time the Company is a party to various legal proceedings in the ordinary course of business. The Company is not currently a party to any litigation that it believes would have a materially adverse affect on the Company's business, financial condition, results of operations, or liquidity.

11. Common Stock Repurchase

On March 18, 2005 the Company publicly announced the authorization by its Board of Directors to repurchase up to 2% of the Company's outstanding common stock (331,796 shares) at fair market value at the date of purchase. At a meeting held June 10, 2005, the Board of Directors of Petroleum Development Corporation approved an amendment of the size of the stock repurchase from 2% to 10% (1,658,980 shares) of the Company's then outstanding common stock. Under the program, the Board has discretion as to the dates of purchase and amounts of stock to be purchased and whether or not to make purchases. This program expired on December 31, 2005. The following activity has occurred since inception of the plan on March 18, 2005 until September 30, 2005.

Month of Purchase	May, 2005
Average Price paid per share	$23.75
Broker/Dealer	McDonald Investments
Number of Shares Purchased	331,796
Remaining Number of Shares to purchase	1,327,184

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

2005 Restatement

As described in our Amended Annual Report on Form 10-K/A for the year ended December 31, 2004 and our Amended Quarterly Report on Form 10-Q/A for the three months ended March 31, 2005, we restated certain financial statements and other information, including such statements and information for each of the quarters of 2004 and the quarter ended March 31, 2005. These restatements related to our accounting for derivative transactions, certain aspects of the Company's oil and gas property accounting, asset retirement obligations, and accounting for income taxes. The following discussions have been restated for the above mentioned restatement and all numbers restated are marked as restated.

The Company has recorded historically strong revenues, income and cash flow for both the third quarter and the first nine months of 2005. High oil and natural gas prices in combination with record Company production have been the largest contributors to both income and cash flow. The high energy prices have also increased the Company's revenues for sales of Company-owned production. Management also believes that high energy prices have increased the attractiveness of its partnership investment programs to investors resulting in a significant increase in the sale of program interests and as a result increased drilling activity, and revenues for the Drilling and Development segment. The new wells drilled for the partnerships also led to an increase in revenues for operating wells for the partnerships and others.

The increased level of activities also increased the costs associated with the drilling and development and well operations activities since more goods, services and other costs were incurred as a result of the higher levels of activities.

The increased profitability and cash flow from operations allowed the Company to continue to invest in capital projects. The majority of the capital investment was for oil and gas drilling and development activities. In addition, the Company repurchased common stock for approximately $7.9 million.

A more detailed explanation of the various components for the most recent quarter and nine months follows:

Results of Operations

Three Months Ended September 30, 2005 Compared with September 30, 2004

Revenues

Total revenues for the three months ended September 30, 2005 were $85.8 million compared to a restated $72.3 million for the three months ended September 30, 2004, an increase of approximately $13.5 million or 18.7 percent. Such increase was a result of increased drilling revenues, oil and gas sales and well operations and pipeline income, offset in part by a decrease in gas sales from marketing activities.

Costs and Expenses

Costs and expenses for the three months ended September 30, 2005 were $63.8 million compared to a restated $57.2 million for the three months ended September 30, 2004, an increase of approximately $6.6 million or 11.5 percent. Such increase was primarily the result of increased cost of oil and gas well drilling operations, oil and gas production and well operations costs, general and administrative costs, and depreciation, depletion and amortization, offset in part by a decrease in the cost of gas marketing activities.

Drilling Operations

Drilling revenues for the three months ended September 30, 2005 were $39.7 million compared to $30.4 million for the three months ended September 30, 2004, an increase of approximately $9.3 million or 30.6 percent. Such increase was due to the increased drilling funds raised through the Company's Public Drilling Programs. The Company started the third quarter of 2005 with advances for future drilling from June 30, 2005 of $63.9 million compared with advances for future drilling of $42.5 million at the beginning of the third quarter of 2004. We believe in part that this increase in drilling program partnership subscriptions is fueled by the increase in oil and natural gas prices which has improved the performance of our prior programs which in turn has helped to increase our current drilling program sales.

Oil and gas well drilling operations costs for the three months ended September 30, 2005 were $36.2 million compared to $26.0 million for the three months ended September 30, 2004, an increase of approximately $10.2 million or 39.2 percent. Such increase was due to the higher levels of drilling activity from our Public Drilling Programs referred to above. The gross margin on the drilling activities for the three months ended September 30, 2005 was 8.9% compared with 14.4% for the three months ended September 30, 2004, a decrease in gross margin of 5.5% as a result of the rising well fracturing and steel costs for casing and other equipment. For the first two partnerships in 2005, the Company raised its footage-based drilling rates it charges to its Public Drilling Partnerships. The third partnership and future partnerships will be drilled on a cost plus basis that will mitigate these fluctuations in drilling margins.

Natural Gas Marketing Activities

Natural gas sales from the marketing activities of Riley Natural Gas (RNG), the Company's gas marketing subsidiary, for the three months ended September 30, 2005 were $15.0 million compared to a restated $22.6 million for the three months ended September 30, 2004, a decrease of approximately $7.6 million or 33.6 percent. Such decrease was due to unrealized losses on derivative transactions which amounted to approximately $16.3 million and $1.4 million for the three months ended September 30, 2005 and 2004, respectively, offset in part by higher volumes of natural gas sold and significantly higher average sales prices.

The costs of gas marketing activities for the three months ended September 30, 2005 were $14.3 million compared to a restated $22.0 million for the three months ended September 30, 2004, a decrease of $7.7 million or 35.0 percent. Such decrease was due to unrealized gains on derivative transactions which amounted to approximately $16.3 million and $1.5 million for the three months ended September 30, 2005 and 2004, respectively, offset in part by significantly higher average purchase prices and volumes of natural gas purchased for resale. Income before income taxes for the Company's natural gas marketing subsidiary was $759,000 for the three months ended September 30, 2005 compared to an income before income taxes of $591,000 for the three months ended September 30, 2004.

Oil and Gas Sales

Oil and gas sales from the Company's producing properties for the three months ended September 30, 2005 were $28.4 million compared to a restated $16.6 million for the three months ended September 30, 2004 an increase of $11.8 million or 71.1 percent. The increase was due to increased volumes sold at significantly higher average sales prices of oil and natural gas. The volume of natural gas sold for the three months ended September 30, 2005 was 2.7 million Mcf at an average sales price of $8.07 per Mcf compared to 2.6 million Mcf at an average restated sales price of $5.13 per Mcf for the three months ended September 30, 2004. Oil sales were 119,000 barrels at an average sales price of $54.66 per barrel for the three months ended September 30, 2005 compared to 88,000 barrels at an average restated sales price of $37.65 per barrel for the three months ended September 30, 2004. The increase in natural gas volumes was the result of the Company's increased investment in oil and gas properties, primarily recompletions of existing wells, wells drilled in our NECO, Colorado area of operation, and the investment in oil and gas properties we own in our public drilling program partnerships.

Oil and Gas Production

The Company's oil and natural gas production by area of operations along with average sales price is presented below:

	Three Months Ended September 30, 2005			Three Months Ended September 30, 2004		
	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)*	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)*
Appalachian Basin	1,218	394,982	402,290	1,589	458,657	468,191
Michigan Basin	1,177	379,824	386,886	1,301	445,013	452,819
Rocky Mountains	116,170	1,941,513	2,638,533	85,414	1,682,360	2,194,844
Total	118,565	2,716,319	3,427,709	88,304	2,586,030	3,115,854
				(Restated)	(Restated)	(Restated)
Average Price	$ 54.66	$ 8.07	$ 8.29	$ 37.65	$ 5.13	$ 5.32

*One barrel of oil is equal to the energy equivalent of six Mcf of natural gas.

Financial results depend upon many factors, particularly the price of natural gas and our ability to market our production effectively. In recent years, natural gas and oil prices have been among the most volatile of all commodity prices. These price variations can have a material impact on our financial results. Natural gas prices in Colorado continue to trail prices which we receive for our Appalachian and Michigan gas which are based upon NYMEX. The Company's management believes the lower prices in the Rocky Mountain Region, including Colorado, resulted from increasing local supplies that exceeded the local demand and pipeline capacity available to move gas from the region. In 2003 a pipeline expansion project was completed, leading to improved natural gas prices in the region which reduced the local surplus. There is currently a substantial amount of drilling activity in the Rockies, and if future additions to the pipeline system are not made in a timely fashion it is possible that pipeline constraints could create a local oversupply situation in the future which could mean lower natural gas prices. Like most other producers in the area we rely on major interstate pipeline companies to construct these facilities, so their timing and construction is not within our control.

Oil and Gas Derivative Activities

Because of uncertainty surrounding natural gas prices we have used various derivative instruments to manage some of the impact of fluctuations in prices. Through March of 2007 we have in place a series of floors and ceilings on part of our natural gas and oil production. Under the arrangements, if the applicable index rises above the ceiling price, we pay the counterparty, however if the index drops below the floor the counterparty pays us. During the three months ended September 30, 2005 the Company averaged natural gas volumes sold of 905,400 Mcf per month and oil sales of 39,500 barrels per month. The current positions in effect on the Company's share of production are shown in the following table.

		Floors		Ceilings	
		Monthly Quantity Mmbtu	Contract Price	Monthly Quantity Mmbtu	Contract Price
Month Set	Month				
Colorado Interstate Gas (CIG) Based Derivatives (Piceance Basin)					
Feb-04	Oct 05	33,000	$3.10	16,000	$4.43
Mar-05	Oct 05	38,000	$4.75	19,000	$8.12
Jan-05	Nov 2005 - Mar 2006	60,000	$4.50	30,000	$7.15
Jul-05	Nov 2005 - Mar 2006	27,500	$6.50	13,750	$8.27
Sep-05	Nov 2005 - Mar 2006	78,700	$9.00	-	-
Mar-05	Apr 2006 - Oct 2006	42,000	$4.50	21,000	$7.25
Jul-05	Apr 2006 - Oct 2006	27,500	$5.50	13,750	$7.63
Jul-05	Nov 2006 - Mar 2007	27,500	$6.00	13,750	$8.40
NYMEX Based Derivatives - (Appalachian and Michigan Basins)					
Feb-04	Oct 05	122,000	$4.28	61,000	$5.00
Mar-05	Oct 05	39,000	$5.75	19,500	$8.37
Jan-05	Nov 2005 - Mar 2006	156,000	$5.00	78,000	$8.50
Sep 05	Nov 2005 - Mar 2006	156,000	$10.50	-	-
Mar-05	Apr 2006 - Oct 2006	78,000	$5.50	39,000	$7.40
Jul-05	Apr 2006 - Oct 2006	61,000	$6.25	30,000	$8.98
Jul-05	Nov 2006 - Mar 2007	68,000	$7.00	34,000	$9.27
NYMEX Based Derivatives (NECO) Area					
Feb-04	Oct 05	150,000	$4.26	75,000	$5.00
Jan-05	Nov 2005 - Mar 2006	150,000	$5.00	75,000	$8.45
Panhandle Based Derivatives (NECO) Area					
Sep-05	Nov 2005 - Mar 2006	100,000	$10.00	-	-
Mar-05	Apr 2006 - Oct 2006	150,000	$5.00	75,000	$8.62
Jul-05	Nov 2006 - Mar 2007	150,000	$6.50	75,000	$8.56
Oil – NYMEX Based (Wattenberg)		Bbl		Bbl	
Aug-04	Oct 2005 - Dec 2005	15,000	$32.30	7,500	$40.00

Oil and Gas Production and Well Operations Costs

Oil and gas production and well operations costs from the Company's producing properties for the three months ended September 30, 2005 were $6.5 million compared to $4.0 million for the three months ended September 30, 2004, an increase of $2.5 million or 62.5 percent. Such increase was due to increased production cost and severance and property taxes on the increased volumes and significantly higher average sales prices of natural gas and oil sold, along with the increased number of wells and pipelines operated by the Company. Lifting cost per Mcfe increased from $1.01 per Mcfe during the three months ended September 30, 2004 to $1.37 per Mcfe during the three months ended September 30, 2005 due to increased severance and property taxes on the significantly increased oil and gas prices, along with additional well workovers and production enhancements work performed.

Exploratory Dry Hole Cost

During the second quarter of 2005, the exploratory Fox Federal #1-13 well was deemed to be non-commercial after well tests were completed and will be plugged and abandoned. Under the successful efforts method of accounting, this cost is required to be expensed in the period when such determination is made. The majority of the dry hole costs were recorded in the second quarter with an additional $135,800 expense which is included under exploratory dry hole costs for the three months ended September 30, 2005. There were no exploratory dry hole costs in 2004.

Well Operations and Pipeline Income

Well operations and pipeline income for the three months ended September 30, 2005 was $2.5 million compared to $2.1 million for the three months ended September 30, 2004, an increase of approximately $400,000 or 19.0 percent. Such increase was due to an increase in the number of wells and pipeline systems operated by the Company for our drilling program partnerships as well as third parties.

Other Income

Other income for the three months ended September 30, 2005 was $209,000 compared to $589,000 for the three months ended September 30, 2004, a decrease of $380,000. Such decrease was due to lower management fee income because no partnerships were funded during the quarter ended September 30, 2005.

General and Administrative Expenses

General and administrative expenses for the three months ended September 30, 2005 were $1.6 million compared to $926,000 for the three months ended September 30, 2004, an increase of approximately $700,000 or 75.6 percent. Such increase was due to the costs of complying with the various provisions of Sarbanes Oxley, in particular with Section 404 (Internal Controls), increased costs related to the 2004 and first quarter 2005 restatements discussed earlier in this document and increased administrative and payroll costs associated with an expanding company.

Depreciation, Depletion, and Amortization

Depreciation, depletion, and amortization costs for the three months ended September 30, 2005 increased to $5.1 million from a restated $4.3 million for the three months ended September 30, 2004, an increase of approximately $800,000 or 18.6 percent. Such increase was due to the increased production and investment in oil and gas properties by the Company.

Interest Expense

Interest cost for the three months ended September 30, 2005 was $142,000 compared to a restated $223,000 for the three months ended September 30, 2004, a decrease of $81,000 or 36.3 percent. Such decrease was due to lower average outstanding balances of our credit facility offset in part by an unrealized gain on an interest rate swap in 2004, increased accretion related to asset retirement obligations, and higher interest rates. The Company utilizes its daily cash balances to reduce its line of credit to lower its costs of interest. The average daily outstanding debt balance for the three months ended September 30, 2005 was $8.0 million compared to $11.4 million for the three months ended September 30, 2004.

Oil and Gas Price Risk Management Loss, Net

For the three months ended September 30, 2005, the Company recorded unrealized losses of $7.8 million and realized losses of $2.1 million compared to the three months ended September 30, 2004, which is comprised of a restated unrealized loss of $1.9 million and restated realized losses of $463,000. The 2005 change is the result of increasing natural gas and oil prices. Oil and gas price risk management (gain) loss, net is comprised of the change in fair value of oil and natural gas derivatives related to our oil and gas production (this line item does not include commodity based derivative transactions related to transactions from marketing activities).

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes increased from approximately 36.3 percent to 37.0 percent primarily because of a reduction in the benefit from percentage depletion, offset in part by additional benefit to be realized for the tax deduction for domestic production activities.

Net income and Earnings Per Share

Net income for the three months ended September 30, 2005 was $7.5 million compared to a restated net income of $7.9 million for the three months ended September 30, 2004, a decrease of approximately $400,000 or 5.1 percent.

Diluted earnings per share for the three months ended September 30, 2005 was $0.46 per share compared to a restated $0.47 per share for the three months ended September 30, 2004, a decrease of $0.01 per share or 2.1 percent.

Nine Months Ended September 30, 2005 Compared with September 30, 2004

Revenues

Total revenues for the nine months ended September 30, 2005 were $252.0 million compared to a restated $215.3 million for the nine months ended September 30, 2004, an increase of approximately $36.7 million or 17.0 percent. Such increase was a result of increased drilling revenues, oil and gas sales, well operations and pipeline income, and other income, offset in part by a decrease in gas sales from marketing activities.

Costs and Expenses

Costs and expenses for the nine months ended September 30, 2005 were $193.6 million compared to a restated $172.9 million for the nine months ended September 30, 2004, an increase of approximately $20.7 million or 12.0 percent. Such increase was primarily the result of the increase in the exploratory dry hole costs of $5.4 million in 2005, cost of oil and gas well drilling operations, oil and gas production costs, general and administrative expenses, and depreciation, depletion and amortization, offset in part by a decrease in cost of gas marketing activities.

Drilling Operations

Drilling revenues for the nine months ended September 30, 2005 were $108.1 million compared to $89.3 million for the nine months ended September 30, 2004, an increase of approximately $18.8 million or 21.1 percent. Such increase was due to the increased drilling funds raised through the Company's Public Drilling Programs. During the first nine months of 2005 the Company funded two drilling programs with total subscriptions of $80.0 million and has commenced drilling of the partnership wells. We believe in part that this increase in drilling program partnership subscriptions is fueled by the increase in oil and natural gas prices which have improved the performance of our prior programs which in turn was helped to increase our current drilling program sales.

Oil and gas well drilling operations costs for the nine months ended September 30, 2005 were $95.1 million compared to $76.3 million for the nine months ended September 30, 2004, an increase of approximately $18.8 million or 24.6 percent. Such increase was due to the higher levels of drilling activity from our Public Drilling Programs referred to above. The gross margin on the drilling activities for the nine months ended September 30, 2005 was 12.0 percent compared with 14.6 percent for the nine months ended September 30, 2004, a decrease in gross margin of 2.6 percent as a result of the rising well fracturing and steel costs for casing and other well equipment. For the first two partnerships in 2005, the Company raised its footage-based drilling rates it charges to its Public Drilling Partnerships. The third partnership and future partnerships will be drilled on a cost plus basis that will mitigate these fluctuations in drilling margins.

Natural Gas Marketing Activities

Natural gas sales from the marketing activities of Riley Natural Gas (RNG), the Company's marketing subsidiary, for the nine months ended September 30, 2005 were $58.4 million compared to a restated $69.6 million for the nine months ended September 30, 2004, a decrease of approximately $11.2 million or 16.1 percent. Such decrease was due to unrealized losses on derivative transactions which amounted to approximately $21.0 million and a restated $3.9 million for the nine months ended September 30, 2005 and 2004, respectively, offset in part by higher volumes of natural gas sold, along with significantly higher average sales prices.

The cost of gas marketing activities for the nine months ended September 30, 2005 was $58.3 million compared to a restated $68.5 million for the nine months ended September 30, 2004, a decrease of $10.2 million or 14.9 percent. Such decrease was due to unrealized gains on derivative transactions which amounted to approximately $20.1 million and a restated $3.0 million for the nine months ended September 30, 2005 and 2004, respectively, offset in part by higher volumes of natural gas purchased for resale, along with higher average purchase prices. Income before income taxes for the Company's natural gas marketing subsidiary decreased from a restated $1.1 million for the nine months ended September 30, 2004 to $250,000 for the nine months ended September 30, 2005.

Oil and Gas Sales

Oil and gas sales from the Company's producing properties for the nine months ended September 30, 2005 were $68.6 million compared to a restated $49.1 million for the nine months ended September 30, 2004 an increase of $19.5 million or 39.7 percent. The increase was due to increased volumes sold at significantly higher average sales prices of oil and natural gas. The volume of natural gas sold for the nine months ended September 30, 2005 was 8.1 million Mcf at an average sales price of $6.52 per Mcf compared to 7.88 million Mcf at an average restated sales price of $5.04 per Mcf for the nine months ended September 30, 2004. Oil sales were 331,000 barrels at an average sales price of $47.60 per barrel for the nine months ended September 30, 2004 compared to 289,000 barrels at an average restated sales price of $34.78 per barrel for the nine months ended September 30, 2004. The increase in natural gas volumes was the result of the Company's increased investment in oil and gas properties, primarily recompletions of existing wells, wells drilled in our NECO, Colorado area of operation, and the investment in oil and gas properties we own in our public drilling program partnerships.

Oil and Gas Production

The Company's oil and natural gas production by area of operations along with average sales price is presented below:

	Nine Months Ended September 30, 2005			Nine Months Ended September 30, 2004		
	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)*	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)*
Appalachian Basin	3,073	1,238,724	1,257,162	3,931	1,346,915	1,370,501
Michigan Basin	3,391	1,172,638	1,192,984	4,305	1,314,829	1,340,659
Rocky Mountains	324,355	5,698,298	7,644,428	280,308	5,093,748	6,775,596
Total	330,819	8,109,660	10,094,574	288,544	7,755,492	9,486,756
				(Restated)	(Restated)	(Restated)
Average Price	$ 47.60	$ 6.52	$ 6.80	$ 34.78	$ 5.04	$ 5.18

*One barrel of oil is equal to the energy equivalent of six Mcf of natural gas.

Financial results depend upon many factors, particularly the price of natural gas and our ability to market our production effectively. In recent years, natural gas and oil prices have been among the most volatile of all commodity prices. These price variations can have a material impact on our financial results. Natural gas prices in Colorado continue to trail prices which we receive for our Appalachian and Michigan gas which are based upon NYMEX. The Company's management believes the lower prices in the Rocky Mountain Region, including Colorado, resulted from increasing local supplies that exceeded the local demand and pipeline capacity available to move gas from the region. In 2003 a pipeline expansion project was completed, leading to improved natural gas prices in the region which reduced the local surplus. There is currently a substantial amount of drilling activity in the Rockies, and if future additions to the pipeline system are not made in a timely fashion it is possible that pipeline constraints could create a local oversupply situation in the future which could mean lower natural gas prices. Like most other producers in the area we rely on major interstate pipeline companies to construct these facilities, so their timing and construction is not within our control. See Management's Discussion and Analysis for the three months ended September 30, 2005 compared with the September 30, 2004 for a complete schedule of current derivative positions.

Oil and Gas Production and Well Operations Costs

Oil and gas production and well operations costs from the Company's producing properties for the nine months ended September 30, 2005 were $15.4 million compared to $11.9 million for the nine months ended September 30, 2004, an increase of approximately $3.5 million or 29.4 percent. Such increase was due to the increased production costs and severance and property taxes on the increased volumes and significantly higher sales prices of natural gas and oil sold, along with the increased number of wells and pipelines operated by the Company. Lifting cost per Mcfe increased from $1.03 per Mcfe during the nine months ended September 30, 2004 to $1.20 per Mcfe during the nine months ended September 30, 2005, due to increased severance and property taxes on the significantly increased oil and gas average sales prices along with additional well workovers and production enhancement work performed.

Exploratory Dry Hole Cost

During the second quarter of 2005, the exploratory Fox Federal #1-13 well, was deemed to be non-commercial after well tests were completed and will be plugged and abandoned. Under the successful efforts method of accounting, this cost is required to be expensed in the period when such determination is made. This amounted to a $5.4 million expense which is included under exploratory dry hole costs. There were no exploratory dry hole costs in 2004.

Well Operations and Pipeline Income

Well operations and pipeline income for the nine months ended September 30, 2005 was $6.8 million compared to $5.8 million for the nine months ended September 30, 2004, an increase of approximately $1.0 million or 17.2 percent. Such increase was due to an increase in the number of wells and pipeline systems operated by the Company for our drilling program partnerships as well as third parties.

Other Income

Other income for the nine months ended September 30, 2005 was $10.0 million compared to $1.3 million for the nine months ended September 30, 2004, an increase of $8.7 million. The increase is a result of a sale of a portion of one of our undeveloped leases in Garfield County, Colorado, which we sold in the first quarter of 2005 (See Footnote 7) for a pre-tax gain of $6.2 million, a second quarter gain on sale of some Pennsylvania wells (See Footnote 8) in the amount of $1.7 million, management fees collected from the funding of two drilling partnerships, and interest earned on higher average cash balances and higher interest rates.

General and Administrative Expenses

General and administrative expenses for the nine months ended September 30, 2005 were $4.5 million compared to $2.8 million for the nine months ended September 30, 2004, a increase of approximately $1.7 million or 60.7 percent. Such increase was due to the cost of complying with the various provisions of Sarbanes Oxley, in particular Section 404 (Internal Controls), increased costs related to the 2004 and first quarter 2005 restatements discussed earlier in this document, and increased administrative and payroll costs associated with an expanding company.

Depreciation, Depletion, and Amortization

Depreciation, depletion, and amortization costs for the nine months ended September 30, 2005 increased to $14.8 million from a restated $13.3 million for the nine months ended September 30, 2004, an increase of approximately $1.5 million or 11.3 percent. Such increase was due to increased production and investment in oil and gas properties by the Company.

Interest Expense

Interest costs for the nine months ended September 30, 2005 was $433,000 compared to a restated $627,000 for the three months ended September 30, 2004, a decrease of $194,000 or 30.9 percent. Such decrease is due to lower average outstanding balances of our credit facility offset in part by an unrealized gain on an interest rate swap in 2004, increased accretion related to asset retirement obligations, and higher interest rates. The Company utilizes its daily cash balances to reduce its line of credit to lower its cost of interest. The average daily outstanding debt balance for the nine months ended September 30, 2005 was $3.3 million compared to $11.9 million for the nine months ended September 30, 2004.

Oil and Gas Price Risk Management Loss, Net

For the nine months ended September 30, 2005, the Company recorded unrealized losses of $9.3 million and realized losses of $3.4 million compared to the nine months ended September 30, 2004 balance which is comprised of a restated unrealized loss of $3.1 million and restated realized losses of $933,000. The 2005 change is the result of increasing natural gas and oil prices. Oil and gas price risk management (gain) loss, net is comprised of the change in fair value of oil and natural gas derivatives related to our oil and gas production (this line item does not include commodity based derivative transactions related to transactions from marketing activities).

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes increased from approximately 36.1 percent to 37.0 percent primarily because of a reduction in the benefit from percentage depletion, offset in part by additional benefit to be realized for the tax deduction for domestic production activities.

Net income and Earnings Per Share

Net income for the nine months ended September 30, 2005 was $28.5 million compared to a restated net income of $24.1 million for the nine months ended September 30, 2004, an increase of approximately $4.4 million or 18.3 percent.

Diluted earnings per share for the nine months ended September 30, 2005 was $1.73 per share compared to restated $1.45 per share for the nine months ended September 30, 2004, an increase of $0.28 per share or 19.3 percent.

Liquidity and Capital Resources

The Company funds its operations through a combination of cash flow from operations and use of the Company's credit facility. Operational cash flow is generated by sales of natural gas and oil from the Company's well interests, natural gas marketing, profits from well drilling and operating activities from the Company's public drilling programs and others, and natural gas gathering and transportation. Cash payments from Company-sponsored partnerships are used to drill and complete wells for the partnerships, with operating cash flow accruing to the Company to the extent payments exceed drilling costs. The Company utilizes its revolving credit arrangement to meet the cash flow requirements of its operating and investment activities.

Oil and Gas Derivative Activities

Because of the uncertainty surrounding natural gas and oil prices we have used various derivative instruments to manage some of the impact of fluctuations in gas prices. Through March 2007 we have in place a series of floors and ceilings on part of our oil and natural gas production. Under the arrangements, if the applicable index rises above the ceiling price, we pay the counterparty, however if the index drops below the floor the counterparty pays us. See previous pages in this Management's Discussion and Analysis for the schedule of open derivative positions.

The Company also enters into derivative instruments for its partners' share of production as well as its own production. Actual wellhead prices will vary based on local contract conditions, gathering and other costs and factors.

Natural Gas Pricing and Pipeline Capacity

The Company sells natural gas under contracts that are priced based on spot prices or price indexes that reflect current market prices for the commodity. As a result variations in the market are reflected in the revenue we receive. The price of natural gas has varied substantially over short periods of time in the past, and there is every reason to expect a continuation of that variability in the future. During the first three quarters prices for natural gas were close to or above record levels, and future expectations as reflected in the NYMEX futures market are for continuing high price levels for the balance of 2005 and beyond. Strong domestic and international demand for energy and inadequate short term supplies are believed to be key causes of the strong prices. High prices could encourage the development of new energy sources and reduced consumption as users find more efficient ways to use energy or substitute other energy forms. High energy prices could also slow global economic growth, further reducing demand. As a result the energy price outlook could change rapidly from current expectations. Reduced natural gas prices would reduce the profitability and cash flow from the Company’s gas production operations.

Natural gas prices throughout the country tend to be fairly closely related after allowing for differences in the quality and energy content of the gas, the location and distance to market, and other factors. Sometimes prices in a particular area may vary from historical relationships. This can occur when a local condition restricts the marketability of the natural gas. For example limits on pipeline delivery capacity for natural gas can result in lower than normal prices for wells that use the system to deliver gas to market. This situation occurred in 2002 to 2003 in the Rocky Mountains, when the productive capacity of wells in the region exceeded the amount of gas that could be used by local markets or shipped out of the area. In order to access the available capacity producers were forced to sell their gas at lower than normal prices with the alternative being to shut wells in. Since that time, additional pipeline capacity has been added, and further additions are planned in the future, so prices have returned to the historical relationship to other producing regions. However future delivery constraints could result in lower than anticipated prices or production in any of the Company’s producing areas.

Oil Pricing

Oil prices were near or above record levels for most of the first three quarters of 2005. The Company's oil prices are largely determined by oil prices in the world market. Global supply and demand and geopolitical factors are the key determinants of oil prices. The rapid growth of energy use in developing countries, most notably China, is driving a rapid increase in worldwide oil consumption. Higher prices could result in reduced consumption and/or increasing supplies that could moderate the current high price levels. Over the past several years oil has been an increasing part of the Company's production mix. As a result higher oil prices have contributed to the Company's increased revenue from oil and gas sales more than in the past, and the Company would suffer a greater impact if oil prices were to decrease.

Public Drilling Programs

During January, 2005, the Company commenced sales and funded its first 2005 Partnership (PDC 2005-A) at its maximum subscriptions of $40 million, the largest PDC partnership at that time. The Company commenced the drilling operations of the partnership late in the first quarter and will continue to drill for the partnership into the second and third quarters of 2005.

In April, 2005, the Company commenced sales and funded its second 2005 Partnership (PDC 2005-B) at its maximum allowable subscriptions of $40 million. The Company commenced drilling operations of this partnership late in the second quarter and plans to continue to drill for the partnership during the fourth quarter of 2005.

In December, 2005, the Company commenced sales and funded its third 2005 partnership, a private limited partnership, Rockies Region Private Limited Partnership with subscriptions of approximately $36 million. Drilling operations will commence in the first quarter of 2006.

Substantially all of the Company's drilling programs contain a repurchase provision where Investors may request the Company to repurchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), only if investors request the Company to repurchase such units subject to the Company's financial ability to do so. The maximum annual 10% repurchase obligation, if requested by the investors, is currently approximately $8.4 million. The Company has adequate liquidity to meet this obligation. During the first nine months of 2005 the Company has spent $248,100 under this provision.

Drilling Activity

Through the first nine months of 2005 the Company drilled along with its public drilling fund partnerships a total of 121 wells with only one developmental dry hole. The Company drilled 96 successful wells in its Wattenberg field in the Denver-Julesberg Basin and 25 successful wells in the Piceance Basin in western Colorado, all of the wells that the Company drills in these two areas are in conjunction with its public drilling fund partnerships. The Company plans to conduct the remainder of its 2005 partnership drilling activity in these two areas.

Through the first nine months of 2005, the Company also drilled for its own account 53 gross (34 net) wells in its northeast Colorado properties (NECO). The wells are being drilled on locations created by the regulatory approval of the reduction in well spacing from 80 to 40 acres on the properties the Company acquired in Yuma County, Colorado in 2003.

Exploratory Wells

During the second quarter of 2005, the exploratory Fox Federal #1-13 well, was deemed to be non-commercial after well tests were completed and will be plugged and abandoned. Under the successful efforts method of accounting, this cost is required to be expensed in the period when such determination is made. This amounted to a $5.0 million expense which is included in the Income Statement under Exploratory Dry Hole Costs.

The Company's second exploratory well, the Coffeepot Springs #24-34 has been drilled to total depth, completed in three zones, tested and has been deemed to be productive under the successful efforts method of accounting. The Company has a 100% working interest in this well. The cost of this well, which is approximately $5.2 million as of November 30, 2005 will be capitalized and depreciated over the life of the well using the units of production depreciation method.

Early in the third quarter the Company commenced the drilling of a horizontal Bakken exploratory well, the Fedora #34-22H in Dunn County, North Dakota which has been drilled to total depth, completed and placed in production in late September, 2005. The Company has a 100% working interest in this well. The cost of this well, which is approximately $4.1 million as of November 30, 2005, will be capitalized and depreciated over the life of the well using units of production depreciation method.

All of the costs of the above three exploratory wells were incurred 100% by the Company as no costs were incurred by the drilling fund partnerships.

Purchase of Oil and Gas Properties

Although the Company made several offers to purchase producing oil and gas properties from other companies during the first nine months of 2005, it was not successful in purchasing any of those properties. The Company did purchase a number of small interests in its partnerships from investors wishing to liquidate their holdings under the repurchase provision of the partnerships.

Costs incurred by the Company in oil and gas acquisitions, exploration and development for the nine months ended September 30, 2005 are presented below:

Property acquisition cost:	
Proved undeveloped properties	$ 5,926,900
Producing properties	273,900
Development costs	34,983,000
Exploration costs	8,777,500
	$ 49,961,300

Common Stock Repurchase Program

On March 18, 2005 the Company publicly announced the authorization by its Board of Directors to repurchase up to 2% of the Company's outstanding common stock (331,796 shares) at fair market value at the date of purchase. At a meeting held June 10, 2005, the Board of Directors of Petroleum Development Corporation approved an amendment of the size of the stock repurchase from 2% to 10% (1,658,980 shares) of the Company's then outstanding common stock. Under the program, the Board has discretion as to the dates of purchase and amounts of stock to be purchased and whether or not to make purchases. This program is scheduled to expire on December 31, 2005. The following activity has occurred since inception of the plan on March 18, 2005 until September 30, 2005.

Month of Purchase	May, 2005
Average Price paid per share	$23.75
Broker/Dealer	McDonald Investments
Number of Shares Purchased	331,796
Remaining Number of Shares to purchase	1,327,184

Working Capital

Although the Working Capital of the Company as of September 30, 2005 is a negative $4.8 million this amount included a net liability of $9.4 million related to the fair value of derivatives. Such amount may or may not be realized depending on the change in the fair value of derivatives between September 30, 2005 and settlement, and will not require additional expenditures of cash since it will be funded with proceeds from future oil and gas sales.

Long-Term Debt

The Company has a $200 million credit facility agented by JP Morgan Securities Inc. and BNP Paribas subject to and secured by adequate levels of oil and gas reserves. The maximum available borrowing base is $125.0 million as of April 1, 2005, of which the Company has activated $80 million of the facility. The Company is required to pay a commitment fee of ¼ percent annually on the unused portion of the activated credit facility. Interest accrues at prime, with LIBOR (London Interbank Market Rate) alternatives available at the discretion of the Company and subject to a pricing grid which defines the spread over LIBOR. No principal payments are required until the credit agreement expires on November 4, 2010.

As of September 30, 2005, the outstanding balance was $14,000,000. Any amounts outstanding under the credit facility are secured by substantially all properties of the Company. The credit agreement requires, among other things, the existence of satisfactory levels of natural gas reserves and maintenance of certain financial and negative covenants customary for a facility of this size. At September 30, 2005, the outstanding balance was subject to a prime rate of 6.75%. The Company has been granted a waiver through January 12, 2006 for the delivery of its quarterly reporting requirements for the quarter ended September 30, 2005.

Contractual Obligations

Contractual obligations and due dates are as follows:

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	Payments due by period				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-Term Debt	$ 14,000,000	$ -	$ -	$ 14,000,000	$ -
Operating Leases	658,700	243,000	307,200	74,500	34,000
Asset Retirement Obligation	8,187,100	50,000	100,000	100,000	7,937,100
Drilling Rig Commitment	25,533,200	5,621,000	11,242,000	8,670,200	-
Derivative Agreements	48,576,000	41,417,000	7,159,000	-	-
Other Liabilities	3,485,900	40,000	250,000	250,000	2,945,900
Total	$ 100,440,900	$ 47,371,000	$ 19,058,200	$ 23,094,700	$ 10,917,000

Long-term debt in the above table does not include interest as interest rates are variable and principal balances fluctuate significantly from period to period. The Company continues to pursue capital investment opportunities in producing natural gas properties as well as its plan to participate in its sponsored natural gas drilling partnerships. Management believes that the Company has adequate capital to meet its operating requirements.

Commitments and Contingencies

As Managing General Partner of 10 private partnerships and 64 public partnerships, the Company has liability for any potential casualty losses in excess of the partnership assets and insurance. The Company is generally the sole general partner of each of these various limited partnerships. The Company believes its casualty insurance coverage is adequate to meet this potential liability.

Factors That May Affect Future Results and Financial Conditions

In the course of its normal business the Company is subject to a number of risks that could potentially adversely impact its revenues, expenses and financial condition. The following is a discussion of some of the more significant risks.

Drilling of oil and natural gas wells is highly speculative and may be unprofitable or result in the loss of the entire investment in a well and the lease on which it is located. To the extent the Company drills unsuccessful developmental wells its future profitability will be reduced on production from the field where the well is located, since the investment in the well will be included in the investment in the field and depreciated on the unit-of-production method. Recently the Company has begun drilling several planned exploratory wells that could lead to significant future development opportunities. Under the Successful Efforts method used by the Company, the costs of exploratory dry holes are taken as an expense in the period when it is determined that they are non-productive. As a result exploratory dry holes, if any additional are drilled, will result in an immediate reduction in net income for that period.

Reductions in prices of oil and natural gas reduce the profitability of the Company's production operations. Revenue from the sale of oil and gas increases when prices increase and declines when prices decrease. These price changes can occur rapidly and are not predictable nor within the control of the Company.

Changes in prices of oil and natural gas may also affect sales of drilling programs. Recent energy price increases have coincided with increased sales of the Company's partnership investments, and increased profitability from those operations. It is likely that declining prices could have the opposite effect, reducing partnership sales and profitability. Because the Company has not been able to meet the demand for oil and gas investments from its Broker/Dealer network, those Broker/Dealers have been seeking investments from other oil and gas program sponsors. These new competitors could potentially take business from the Company, particularly in a declining price market for oil and gas.

Increases in prices of oil and natural gas have increased the cost of drilling, the cost of potential acquisitions and other factors affecting the performance of the Company in both the short and long term. In the current high price environment most oil and gas companies have increased their expenditures for drilling new wells. This has resulted in increased demand and higher prices for leases, oilfield services and well equipment. Similarly higher energy prices have increased the price purchasers are willing to pay for producing properties and increased competition for the properties that are available. These factors make it more difficult to add to the Company's production, and increase the cost of additions. To the extent that new reserves and production are added at these higher prices, the risk to the Company of decreased profitability from future decreases in oil and gas prices is increased.

The Company's derivative activities could result in reduced revenue compared to the level the Company would experience if no derivative instruments were in place. The Company uses derivative instruments to reduce the impact of price movements on revenue. While these derivative instruments protect the Company against the impact of declining prices, they also may limit the positive impact of price increases. As a result the Company may have lower revenues when prices are increasing than might otherwise be the case.

The high level of drilling activity could result in an oversupply of natural gas on a regional or national level resulting in much lower commodity prices. Recently the natural gas market been characterized by excess demand compared to the supplies available. The high level of drilling, combined with reduction in demand resulting from high prices could result in an oversupply of natural gas. On a local level increasing supplies could exceed available pipeline capacity. In both cases the result would probably be lower prices for the natural gas the Company produces and reduced profitability for the Company.

The Company owns interests in and operates more than 2,600 wells and drills many new wells each year. Environmental hazards and unpredictable costs associated with those wells could have a negative impact on the performance of the Company. While many of the wells the Company drills are relatively low risk development wells, the Company also plans to drill exploratory wells to test new areas in coming months. Under the terms of the Company's drilling agreements with its partnerships the Company also bears the risk for the investor partners interests in new wells through an indemnification agreement. The costs associated with problems encountered in drilling, completing and operating wells can be significant, and could adversely affect the profitability of the Company if such problems are encountered.

Changes in the Tax Code could reduce the attractiveness of the Company's partnership investments and reduce the revenues and profitability of those operations. The partnership interests sold by the Company offer investors significant tax benefits under current tax regulations. If the Congress changes the Code and eliminates or reduces those benefits investments in the partnerships would be less attractive to investors and fewer investors might invest.

Increasing interest rates could increase the cost of the Company's borrowing. Higher interest rates would increase the interest costs of the Company's borrowing, and would make additional borrowing less attractive. This could also make potential acquisitions and other activities funded with borrowed money less profitable, potentially reducing the rate of growth of production and reserves. Consequently, the Company's profitability could be reduced.

Critical Accounting Policies and Estimates

We have identified the following policies as critical to our business operations and the understanding of our results of operations. This listing is not a comprehensive list of all of our accounting policies. In many cases, the accounting treatment of a particular transaction is specifically dictated by accounting principles generally accepted in the United States, with no need for management's judgment in their application. There are also areas in which management's judgment in selecting any available alternative would not produce a materially different result. However, certain of our accounting policies are particularly important to the portrayal of our financial position and results of operations and may require the application of significant judgment by our management; as a result, they are subject to an inherent degree of uncertainty. In applying those policies, our management uses its judgment to determine the appropriate assumptions to be used in the determination of certain estimates. Those estimates are based on our historical experience, our observance of trends in the industry, and information available from other outside sources, as appropriate. For a more detailed discussion on the application of these and other accounting policies, see "Note 1 - Summary of significant accounting policies" in our annual financial statements and related notes on Form 10-K/A. Our critical accounting policies and estimates are as follows:

Revenue Recognition

The Company's drilling segment recognizes revenue from our drilling contracts with our publicly registered drilling programs using the percentage of completion method. These contracts are footage rate based and completed within nine to twelve months after the commencement of drilling. The Company provides geological, engineering, and drilling supervision on the drilling and completion process and uses subcontractors to perform drilling and completion services. The percentage of completion method measures the percentage of contract costs incurred to date to the estimated total contract costs for each contract. The Company utilizes this method because reasonably dependable estimates of the total estimated costs can be made. Because the revenue recognized depends on estimates of the final contract costs, which are assessed continually during the term of the contract, recognized revenues are subject to revisions as the contract progresses. Anticipated losses, if any, on uncompleted contracts would be recorded at the time that our estimated costs exceeded the contract revenue. The Company has not experienced any contract losses in 2005 or 2004.

Natural gas marketing is recorded on the gross accounting method. Riley Natural Gas ("Riley"), our marketing subsidiary, purchases gas from many small producers and bundles the gas together to sell in larger amounts to purchasers of natural gas for a price advantage. Riley has latitude in establishing price and discretion in supplier and purchaser selection. Natural gas marketing revenues and expenses reflect the full cost and revenue of those transactions because Riley takes title to the gas it purchases from the various producers and bears the risks and enjoys the benefits of that ownership. Both the realized and unrealized portions of the Riley commodity-based derivative transactions for natural gas sales from marketing activities are included in gas sales from marketing activities or cost of gas marketing activities, as applicable.

Sales of natural gas are recognized when natural gas has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. Natural gas is sold by the Company under contracts with terms ranging from one month to three years. Virtually all of the Company's contracts pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of natural gas and prevailing supply and demand conditions, so that the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. As a result, the Company's revenues from the sale of natural gas will suffer if market prices decline and benefit if they increase. The Company believes that the pricing provisions of its natural gas contracts are customary in the industry.

The Company currently uses the "Net-Back" method of accounting for transportation arrangements of our natural gas sales. The Company sells gas at the wellhead and collects a price and recognizes revenues based on the wellhead sales price since transportation costs downstream of the wellhead are incurred by our customers and reflected in the wellhead price.

Sales of oil are recognized when persuasive evidence of a sales arrangement exists, the oil is verified as produced and is delivered in a stock tank, collection of revenue from the sale is reasonably assured and the sales price is determinable. The Company is currently able to sell all the oil that it can produce under existing sales contracts with petroleum refiners and marketers. The Company does not refine any of its oil production. The Company's crude oil production is sold to purchasers at or near the Company's wells under short-term purchase contracts at prices and in accordance with arrangements that are customary in the oil industry.

Well operations and pipeline income is recognized when persuasive evidence of an arrangement exists, services have been rendered, collection of revenues is reasonably assured and the sales price is fixed or determinable. The Company is paid a monthly operating fee for each well it operates for outside owners including the limited partnerships sponsored by the Company. The fee is competitive with rates charged by other operators in the area. The fee covers monthly operating and accounting costs, insurance and other recurring costs. The Company may also receive additional compensation for special non-recurring activities, such as reworks and recompletions.

Valuation of Accounts Receivable

Management reviews accounts receivable to determine which are doubtful of collection. In making the determination of the appropriate allowance for doubtful accounts, management considers the Company's history of write-offs, relationships and overall credit worthiness of its customers, and well production data for receivables related to well operations.

Accounting for Derivatives Contracts at Fair Value

The Company uses derivative instruments to manage its commodity and financial market risks. Accounting requirements for derivatives are complex; interpretation of these requirements by standard-setting bodies is ongoing. The Company currently does not use hedge accounting treatment for its derivatives.

Derivatives are reported on the Condensed Consolidated Balance Sheets at fair value. Changes in fair value of derivatives that are recorded in earnings in the consolidated statements of income as none of the Company's derivatives qualified for hedge accounting under the provisions of FAS 133.

The measurement of fair value is based on actively quoted market prices, if available. Otherwise, the Company seeks indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, measurement involves judgment and estimates. These estimates are based on valuation methodologies considered appropriate by the Company's management. For individual contracts, the use of different assumptions could have a material effect on the contract's estimated fair value.

Use of Estimates in Long-Lived Asset Impairment Testing

Impairment testing for long-lived assets and intangible assets with definite lives is required when circumstances indicate those assets may be impaired. In performing the impairment test, the Company estimates the future cash flows associated with individual assets or groups of assets. Impairment must be recognized when the undiscounted estimated future cash flows are less than the related asset's carrying amount. In those circumstances, the asset must be written down to its fair value, which, in the absence of market price information, may be estimated as the present value of its expected future net cash flows, using an appropriate discount rate. Although cash flow estimates used by the Company are based on the relevant information available at the time the estimates are made, estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results.

Oil and Gas Properties

Exploration and development costs are accounted for by the successful efforts method.

The Company assesses impairment of capitalized costs of proved oil and gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows on a field-by-field basis using expected prices. Prices utilized in each year's calculation for measurement purposes and expected costs are held constant throughout the estimated life of the properties. If net capitalized costs exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value which would consider future discounted cash flows.

Property acquisition costs are capitalized when incurred. Geological and geophysical costs and delay rentals are expensed as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether the wells have discovered economically producible reserves. If reserves are not discovered, such costs are expensed as dry holes. Development costs, including equipment and intangible drilling costs related to both producing wells and developmental dry holes are capitalized.

Unproved properties or leases are written-off to expense when it is determined that they will expire or be abandoned.

Costs of proved developed properties, exploration and development costs and equipment, are depreciated or depleted by the unit-of-production method based on estimated proved developed producing oil and gas reserves. Property acquisition costs are depreciated or depleted on the unit-of-production method based on estimated proved oil and gas reserves. The Company obtains new reserve reports from an independent petroleum engineer annually as of December 31st of each year. The Company adjusts for any major acquisitions, new drilling and divestures during the year as needed.

Upon sale or retirement of complete fields of depreciable or depletable property, the book value thereof, less proceeds or salvage value, is credited or charged to income. Upon sale of a partial unit of property, the proceeds are credited to accumulated depreciation and depletion.

Deferred Tax Asset Valuation Allowance

Deferred tax assets are recognized for deductible temporary differences, net operating loss carry forwards, and credit carry forwards if it is more likely than not that the tax benefits will be realized. To the extent a deferred tax asset cannot be recognized under the preceding criteria, a valuation of allowance has been established.

The judgments used in applying the above policies are based on management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results may differ from those estimates.

New Accounting Standards

The FASB issued FIN 46, "Consolidation of Variable Interest Entities", in January 2003 and amended the interpretation in December 2003. A variable interest entity (VIE) is an entity in which its voting equity investors lack the characteristics of having a controlling financial interest or where the existing capital at risk is insufficient to permit the entity to finance its activities without receiving additional financial support from other parties. FIN 46 requires the consolidation of entities which are determined to be VIEs when the reporting company determines itself to be the primary beneficiary (the entity that will absorb a majority of the VIE's expected losses, receive a majority of the VIE's residual returns, or both). The amended interpretation was effective for the first interim or annual reporting period ending after March 15, 2004, with the exception of special purpose entities for which the statement was effective for periods ending after December 15, 2003. We have completed a review of our partnership investments and have determined that those entities do not qualify as VIEs.

On December 16, 2004, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 123R (revised 2004), "Share-Based Payment" which is a revision of FASB Statement No. 123, "Accounting for Stock-Based Compensation". Statement 123R supersedes APB opinion No. 25, "Accounting for Stock Issued to Employees", and amends FASB Statement No. 95, "Statement of Cash Flows". Generally, the approach in Statement 123R is similar to the approach described in Statement 123. However, Statement 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their fair values. Pro-forma disclosure is no longer an alternative. The provisions of this statement become effective for our first quarter 2006. Management has not determined the impact that this statement will have on our consolidated financial statements.

Recently Issued Accounting Pronouncements

On March 30, 2005, the FASB issued FASB Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations” (FIN No. 47). This interpretation clarifies that the term “conditional asset retirement obligation” as used in Statement No. 143 refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity incurring the obligation. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. Thus, the timing and/or method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. Uncertainty about the timing and/or method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability, rather than the timing of recognition of the liability, when sufficient information exits. FIN No. 47 will be effective for the Company no later than the end of the fiscal year ended December 31, 2005. The Company does not expect any impact on the Company’s financial position or results of operations upon adoption of FIN No. 47.

On April 4, 2005, the FASB issued FASB Staff Position (FSP) FAS 19-1 "Accounting for Suspended Well Costs." This staff position amends FASB Statement No. 19 "Financial Accounting and Reporting by Oil and Gas Producing Companies" and provides guidance about exploratory well costs to companies which use the successful efforts method of accounting. The position states that exploratory well costs should continue to be capitalized if: 1) a sufficient quantity of reserves are discovered in the well to justify its completion as a producing well and 2) sufficient progress is made in assessing the reserves and the well's economic and operating feasibility. If the exploratory well costs do not meet both of these criteria, these costs should be expensed, net of any salvage value. Additional annual disclosures are required to provide information about management's evaluation of capitalized exploratory well costs. In addition, the FSP requires annual disclosure of: 1) net changes from period to period of capitalized exploratory well costs for wells that are pending the determination of proved reserves, 2) the amount of exploratory well costs that have been capitalized for a period greater than one year after the completion of drilling and 3) an aging of exploratory well costs suspended for greater than one year with the number of wells it related to. Further, the disclosures should describe the activities undertaken to evaluate the reserves and the projects, the information still required to classify the associated reserves as proved and the estimated timing for completing the evaluation. The Company adopted FAS 19-1 during the third quarter of 2005 and will adopt the annual disclosures requirements in the Company's 10-K as of December 31, 2005. The application of this FSP did not have a significant impact on the Company's financial position or results of operations.

In June 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections – a replacement of APB Opinion No. 20 and FASB Statement No. 3,* which replaces Accounting Principles Board Opinion No. 20, *Accounting Changes,* and SFAS No. 3, *Reporting Accounting Changes in Interim Financial Statements,* and changes the requirements for the accounting for and reporting of a change in accounting principle. SFAS No. 154 requires retrospective application for voluntary changes in accounting principle unless it is impracticable to do so, and it applies to all voluntary changes in accounting principle. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. Consequently, we will adopt the provisions of SFAS 154 for our fiscal year beginning January 1, 2006. We currently believe that adoption of the provisions of SFAS No. 154 will not have a material impact on our consolidated financial statements.

In June 2005, the EITF reached a consensus on EITF Issue No. 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights.* This consensus applies to voting right entities not within the scope of FASB Interpretation No. 46(R), *Consolidation of Variable Interest Entities,* in which the investor is the general partner in a limited partnership or functional equivalent. The EITF consensus is that the general partner in a limited partnership is presumed to control that limited partnership regardless of the extent of the general partner's ownership interest and, therefore, should include the limited partnership in its consolidated financial statements. The general partner may overcome this presumption of control and not consolidate the entity if the limited partners have either: (a) the substantive ability to dissolve (liquidate) the limited partnership or otherwise remove the general partner through substantive kick-out rights that can be exercised without having to show cause; or (b) substantive participating rights in managing the partnership. This guidance became immediately effective upon ratification by the FASB on June 2, 2005, for all newly formed limited partnerships and for existing limited partnerships for which the partnership agreements have been modified. For general partners in all other limited partnerships, the guidance is effective no later than the beginning of the first reporting period in fiscal years beginning after December 15, 2005. We do not expect the adoption of this guidance to have a material impact on our consolidated financial statements.

Disclosure Regarding Forward Looking Statements

This Form 10-Q contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical facts included in and incorporated by reference into this Form 10-Q are forward-looking statements. These forward-looking statements are subject to certain risks, trends and uncertainties that could cause actual results to differ materially from those projected. Among those risks, trends and uncertainties are the Company's estimate of the sufficiency of its existing capital sources, its ability to raise additional capital to fund cash requirements for future operations, the uncertainties involved in estimating quantities of proved oil and natural gas reserves, in successfully drilling productive wells and in prospect development and property acquisitions and in projecting future rates of production, the timing of development expenditures and drilling of wells, and the operating hazards attendant to the oil and gas business. In particular, careful consideration should be given to cautionary statements made in this Form 10-Q and in the various reports the Company has filed with the Securities and Exchange Commission. The Company undertakes no duty to update or revise these forward-looking statements.

When used in the Form 10-Q, the words, "expect," "anticipate," "intend," "plan," "believe," "seek," "estimate" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain these identifying words. Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements for a number of important reasons, including those discussed under "Management's Discussions and Analysis of Financial Condition and Results of Operations" and elsewhere in this Form 10-Q.

Item 3. Quantitative and Qualitative Disclosure About Market Rate Risk

Interest Rate Risk

There have been no material changes in the reported market risks faced by the Company since December 31, 2004.

Commodity Price Risk

The Company utilizes commodity-based derivative instruments to manage a portion of its exposure to price risk from its oil and natural gas sales and marketing activities. These instruments consist of NYMEX-traded natural gas futures contracts and option contracts for Appalachian and Michigan production and CIG-based contracts traded by JP Morgan for Colorado production and purchase and sales contracts with customers deemed to be derivatives used by its natural gas marketing company, Riley Natural Gas. These derivative instruments have the effect of locking in for specified periods (at predetermined prices or ranges of prices) the prices the Company will receive for the volume to which the derivative relates and, in the case of RNG, the cost of gas supplies purchased for marketing activities. As a result, while these derivative instruments are structured to reduce the Company's exposure to changes in price associated with the commodity, they also limit the benefit the Company might otherwise have received from price changes associated with the commodity. The Company's policy prohibits the use of oil and natural gas future and option contracts for speculative purposes.

The following tables summarize the open derivative and purchase and sale contracts for Riley Natural Gas and PDC as of September 30, 2005 and September 30, 2004.

Riley Natural Gas
Open Derivatives Contracts

Commodity	Type	Quantity Gas-Mmbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Value
Total Contracts as of September 30, 2005					
Natural Gas	Cash Settled Sale	3,444,000	$7.08	$ 24,392,650	$ (18,292,508)
Natural Gas	Cash Settled Purchase	980,000	$8.12	$ 7,953,380	$ 4,635,487
Natural Gas	Cash Settled Sale Option	80,000	$5.56	$ -	$ 1
Natural Gas	Cash Settled Purchase Option	40,000	$7.06	$ -	$ (253,652)
Natural Gas	Physical Contract Sale	493,388	$7.79	$ 3,843,514	$ (3,133,759)
Natural Gas	Physical Contract Purchase	3,111,300	$7.32	$ 22,785,381	$ 16,897,291
Contracts maturing in 12 months following September 30, 2005					
Natural Gas	Cash Settled Sale	2,724,000	$7.28	$ 19,834,820	$ (15,485,473)
Natural Gas	Cash Settled Purchase	870,000	$8.20	$ 7,129,880	$ 4,266,891
Natural Gas	Cash Settled Sale Option	80,000	$5.56	$ -	$ 1
Natural Gas	Cash Settled Purchase Option	40,000	$7.06	$ -	$ (253,652)
Natural Gas	Physical Contract Sale	469,413	$7.79	$ 3,657,341	$ (3,049,437)
Natural Gas	Physical Contract Purchase	2,481,300	$7.62	$ 18,901,381	$ 14,160,744

Prior Year Total Contracts as of September 30, 2004					
Natural Gas	Cash Settled Sale	3,920,000	$5.51	$ 21,616,540	$ (5,842,600)
Natural Gas	Cash Settled Purchase	1,150,000	$6.11	$ 7,029,540	$ 706,260
Natural Gas	Cash Settled Sale Option	660,000	$5.20	$ -	$ -
Natural Gas	Cash Settled Purchase Option	330,000	$6.97	$ -	$ (124,075)
Natural Gas	Physical Contract Sale	951,399	$7.63	$ 7,263,314	$ 58,859
Natural Gas	Physical Contract Purchase	3,893,900	$5.74	$ 22,339,079	$ 4,569,306

The maximum term over which RNG is managing exposure to the variability of cash flows for commodity price risk
is 37 months.

Petroleum Development Corporation
Open Derivatives Contracts

Commodity	Type	Quantity Gas-Mmbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Value
Total Contracts as of September 30, 2005					
Natural Gas	Purchase	11,754	$6.82	$ 80,182	$ 85,389
Natural Gas	Sale Option	7,776,180	$6.43	$ -	$ 909,974
Natural Gas	Purchase Option	3,053,590	$8.19	$ -	$ (11,334,641)
Crude Oil	Sale Option	38,889	$32.30	$ -	$ 3
Crude Oil	Purchase Option	19,445	$40.00	$ -	$ (506,298)
Contracts maturing in 12 months following September 30, 2005					
Natural Gas	Purchase	11,754	$6.82	$ 80,182	$ 85,389
Natural Gas	Sale Option	6,135,088	$6.45	$ -	$ 602,627
Natural Gas	Purchase Option	2,233,044	$8.02	$ -	$ (9,194,020)
Crude Oil	Sale Option	38,889	$32.30	$ -	$ 3
Crude Oil	Purchase Option	19,445	$40.00	$ -	$ (506,298)
Prior Year Total Contracts as of September 30, 2004					
Natural Gas	Purchase	11,679	$4.82	$ 56,254	$ 22,202
Natural Gas	Sale Option	4,887,080	$4.64	$ -	$ 247,949
Natural Gas	Purchase Option	1,974,075	$5.57	$ -	$ (2,691,500)
Crude Oil	Sale	28,740	$31.63	$ 909,046	$ (489,155)
Crude Oil	Sale Option	172,440	$32.30	$ 5,569,812	$ 50,025
Crude Oil	Purchase Option	86,220	$40.00	$ 3,448,800	$ (649,544)

The maximum term over which PDC is managing exposure to the variability of cash flows for commodity price risk is 18 months.

See "Working Capital" in Management's Discussions of Liquidity and Capital Resources for the effect of these contracts on the Company's Consolidated Balance Sheet.

The average NYMEX closing price for natural gas for the nine months of 2005 and the year 2004 was $7.16 Mmbtu and $6.14 Mmbtu. The average NYMEX closing price for oil for the nine months of 2005 and the year 2004 was $53.40 bbl and $41.44 bbl. Future near-term gas prices will be affected by various supply and demand factors such as weather, government and environmental regulation and new drilling activities within the industry.

Item 4. Controls and Procedures

(a) Evaluation of disclosure controls and procedures

The Company maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in the Company's reports under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to management, including the Company's Chief Executive Officer and Chief Financial Officer, and the Company's Audit Committee and Board of Directors, as appropriate, to allow timely decisions regarding required disclosure. The Company's management, with participation of the Company's Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) as of the end of the period covered by this quarterly report on Form 10-Q.

As previously disclosed in the Company's Amended Annual Report on Form 10-K/A for the year ended December 31, 2004, and in its amended quarterly report on Form 10-Q/A for the quarter ended March 31, 2005, the Company determined that, as of December 31, 2004 and March 31, 2005, there were material weaknesses affecting its internal control over financial reporting and, as a result of those weaknesses, the Company's disclosure controls and procedures were not effective. Based upon the evaluation of the effectiveness of the Company's disclosure controls and procedures as of September 30, 2005, the Company's Chief Executive Officer and Chief Financial Officer concluded that the Company disclosure controls and procedures were not effective.

Remediation of Material Weaknesses in Internal Control

As previously disclosed in the Company's Amended Annual Report on Form 10-K/A for the year ended December 31, 2004, and in its amended quarterly report on Form 10-Q/A for the quarter ended March 31, 2005, the Company determined that, as of the end of the fiscal 2004, there were material weaknesses in its internal control over financial reporting relating to improper accounting of (1) derivatives transactions, (2) oil and gas property, (3) asset retirement obligations, and (4) provision for income taxes. The Company's management and Audit Committee have dedicated significant resources to assessing the underlying issues giving rise to the aforementioned accounting errors and to ensure that proper steps have been and are being taken to improve our internal controls. We have assigned the highest priority to the correction of the related control deficiencies and have taken and will continue to take action to fully correct them. Management is committed to instilling strong control policies and procedures and ensuring that the 'tone at the top' is committed to accuracy and completeness in all financial reporting. The Company's Audit Committee will continually be updated as to the progress and status of the remediation initiatives to ensure they are adequately implemented. As of the date of this filing, while we have corrected the financial statements, we have not completed the remediation of these material weaknesses; however, we believe that the remediation initiatives outlined below, when completed, will be sufficient to eliminate the material weaknesses in internal control over financial reporting as discussed above.

As of the date of this filing, the remediation initiatives management has and will continue to implement include:

- The Company is implementing a training initiative to increase the Company's technical expertise. The programs offered through this training initiative will include basic and advanced oil and natural gas accounting training programs, as well as general accounting, financial reporting (including SEC reporting), and income tax training programs. Also, related to this initiative, the Company has purchased licenses for accounting research software. Additionally, the CFO or a qualified designee will be responsible for the periodic review of the documentation and calculations related to oil and gas properties.

- The Company currently does not use hedge accounting treatment; however, in the future when using hedge accounting, the Company will implement additional controls with respect to accounting for derivative transactions in accordance with SFAS No. 133. These controls include thorough and formal documentation of all potential derivative transactions prior to initiation of the transaction. This documentation will include the hedging relationship, the entity's risk management objective and strategy for undertaking the hedge, including identification of the hedging instrument, the hedged item, the nature of the risk being hedged, and the method of assessing the hedging instrument's effectiveness. The Company is in the process of evaluating derivative accounting software to be implemented to calculate the impact of derivative contracts on the financial statements. The Company will also seek the input of its independent derivative expert to assist with the selection of the derivative accounting software. Additionally, the CFO or a qualified designee will be responsible for the periodic review of the documentation and calculations of derivative transactions. The Company also has utilized a derivative expert to assist the Company in evaluating its current derivative transactions to ensure that they have been properly reported and will utilize derivative experts in the future as needed.
- The Company has re-evaluated and corrected its documentation, policies and procedures, and templates with respect to accounting for its oil and gas properties in compliance with generally accepted accounting principles. The design and effective operation of proper policies and procedures as well as the correction of these documents will ensure the accuracy of oil and gas property valuation in accordance with generally accepted accounting principles. This includes documented procedures to identify significant components of oil and gas property calculations including field designation, reserves and applicable set-up costs. This documentation also includes correcting the carry-forward schedules utilized to calculate the depreciation, depletion and amortization with the correct information and identification of the components of the calculation. Additionally, the CFO or a qualified designee will be responsible for the periodic review of the documentation and accounting for oil and gas properties, including related calculations. Also, the Company plans to utilize an independent specialist to review the Company's accounting for oil and natural gas properties, including the Company's documentation as well as templates. The specialist will be an accounting firm with significant oil and natural gas accounting and income tax experience and SEC experience and will also be utilized in identifying and implementing new accounting standards and review of our income tax reporting procedures.
- The Company has reevaluated and corrected its documentation, policies and procedures, and templates with respect to its accounting for asset retirement obligations. The specialist discussed in the previous paragraph will also be utilized to help verify these practices and implement any new requirements.
- The Company has reevaluated and corrected its documentation, policies and procedures, and templates with respect to its accounting for income taxes and the related disclosures in its financial statements. The Company will utilize a qualified independent tax expert to periodically review the calculation of income taxes and the related disclosures for reporting purposes and to identify and help implement any new rules or regulations.

{b} Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the quarter ended September 30, 2005, that materially affects, or is reasonably likely to materially affect, our internal control over financial reporting. However, subsequent to September 30, 2005, we are in the process of implementing the remedial actions described above.

Although we have taken steps as referred to above to correct the material weaknesses, they were not remediated as of December 31, 2005.

Effective January 1, 2006 the Company reorganized the structure of its accounting department to provide a better distribution of responsibilities and the work load associated with the Company's accounting and financial reporting. As a part of the reorganization, several additional positions were created in the accounting department. The Controller's position was eliminated and new positions for a Director of Accounting Operations and a Director of Financial Reporting were created. The Company's controller was slated to become the Director of Financial Reporting, however, she chose to resign her position with the Company but is continuing to act as a consultant and will continue to perform the same duties until appropriate replacements are trained. The CFO will oversee the responsibilities of the Director of Financial Reporting until a qualified candidate has been hired to fill the position. The Company is currently seeking qualified accountants to fill certain of the new positions. The Company believes that the reorganization, when completed, will allow it to better meet its current financial and accounting obligations and to grow to fill future needs.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings

The Company is not a party to any legal actions that would materially affect the Company's operations or financial statements.

Item 2. Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number Of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
May 1 - May 31, 2005	331,796	$23.75	331,796	1,327,184
Total	331,796	$23.75	331,796	1,327,184

On March 18, 2005 the Company publicly announced the authorization by its Board of Directors to purchase up to 2% of the Company's outstanding common stock (331,796) at fair market value at the date of purchase. At a meeting held June 10, 2005, the Board of Directors of Petroleum Development Corporation approved an amendment of the size of the stock repurchase from 2% to 10% (1,658,980 shares) of the Company's outstanding common stock. Under the program, the Board has discretion as to the dates of purchase and amounts of stock to be purchased and whether or not to make purchases. This program is scheduled to expire on December 31, 2005. See Note 11 to the financial statements above.

Item 6. Exhibits

(a) Exhibits

Exhibit Name	Exhibit Number	Location
Acknowledgement of Independent Registered Public Accounting Firm	23.1	Filed herewith
Rule 13a-14(a)/15d-14(a) Certification by Chief Executive Officer	31.1	Filed herewith.
Rule 13a-14(a)/15d-14(a) Certification by Chief Financial Officer	31.2	Filed herewith.
Title 18 U.S.C. Section 1350 (Section 906 of Sarbanes-Oxley Act of 2002) Certifications by Chief Executive Officer and Chief Financial Officer of Petroleum Development Corporation	32	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.

Petroleum Development Corporation
(Registrant)

Date: January 11, 2006

/s/ Steven R. Williams
Steven R. Williams
Chief Executive Officer and President

Date: January 11, 2006

/s/ Darwin L. Stump
Darwin L. Stump
Chief Financial Officer