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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, 2004

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 XX No __

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 16,565,578 shares of the Company's Common Stock ($.01 par value) were outstanding as of October 31, 2004.

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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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, 2004, the related condensed consolidated statements of income for the three-month and nine-month periods ended September 30, 2004 and 2003, and the related condensed consolidated statements of cash flows for the nine-month periods ended September 30, 2004 and 2003. 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, 2003, 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 February 27, 2004, we expressed an unqualified opinion on those consolidated financial statements in a report that also included an explanatory paragraph referring to changes in accounting principles as discussed in Notes 1 and 13 to these statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2003 is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

KPMG LLP

Pittsburgh, Pennsylvania
November 2, 2004

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Balance Sheets
September 30, 2004 and December 31, 2003

ASSETS

	2004 (Unaudited)	2003
Current assets:		
Cash and cash equivalents	$58,859,700	$80,379,300
Accounts and notes receivable	25,667,500	22,523,600
Inventories	3,908,000	2,557,700
Prepaid expenses	7,647,500	5,907,000
Total current assets	96,082,700	111,367,600
Properties and equipment	290,529,900	265,864,300
Less accumulated depreciation, depletion, and amortization	84,433,700	71,182,100
	206,096,200	194,682,200
Other assets	753,900	672,200
	$302,932,800	$306,722,000

(Continued)

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Balance Sheets, Continued
September 30, 2004 and December 31, 2003

LIABILITIES AND STOCKHOLDERS' EQUITY

	2004 (Unaudited)	2003
Current liabilities:		
Accounts payable and accrued expenses	$57,627,000	$46,267,200
Advances for future drilling contracts	26,478,600	50,458,800
Funds held for future distribution	12,160,800	8,410,900
Total current liabilities	96,266,400	105,136,900
Long-term debt	27,000,000	53,000,000
Other liabilities	3,011,100	2,449,100
Deferred income taxes	27,912,400	21,800,200
Asset retirement obligations	758,200	731,200
Stockholders' equity:		
Common stock par value $0.01 per share; authorized 50,000,000 shares; issued and outstanding 16,287,794 shares and 15,638,733 shares	162,900	156,200
Additional paid-in capital	31,100,100	28,578,100
Retained earnings	121,793,300	96,049,200
Accumulated other comprehensive loss, net	(5,071,600)	(1,178,900)
Total stockholders' equity	147,984,700	123,604,600
	$302,932,800	$306,722,000

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, 2004 and 2003
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
Revenues:				
Oil and gas well drilling operations	$30,394,400	$14,080,100	$89,347,500	$47,444,000
Gas sales from marketing activities	23,983,000	17,686,100	73,451,800	56,644,400
Oil and gas sales	16,117,200	13,088,200	48,172,600	32,866,200
Well operations and pipeline income	2,073,800	1,865,200	5,823,700	5,282,100
Other income	589,000	488,300	1,334,100	1,158,100
	73,157,400	47,207,900	218,129,700	143,394,800
Costs and expenses:				
Cost of oil and gas well drilling operations	26,005,400	11,955,700	76,328,400	39,751,500
Cost of gas marketing activities	23,980,600	17,463,500	72,484,200	55,923,100
Oil and gas production costs	3,952,400	3,986,200	11,894,500	10,303,600
General and administrative expenses	926,300	1,377,300	2,821,400	3,741,600
Depreciation, depletion, and amortization	4,418,800	4,243,200	13,589,800	10,632,400
Interest	252,600	415,000	751,100	911,000
	59,536,100	39,440,900	177,869,400	121,263,200
Income before income taxes and cumulative effect of change in accounting principle	13,621,300	7,767,000	40,260,300	22,131,600
Income taxes	4,929,700	2,563,100	14,516,200	7,303,400
Net income before cumulative effect of change in accounting principle	8,691,600	5,203,900	25,744,100	14,828,200
Cumulative effect of change in accounting principle (net of taxes of $121,700)	-	-	-	(198,600)
Net income	$8,691,600	$5,203,900	$25,744,100	$14,629,600
Basic earnings per common share before accounting change	$ .53	$ .33	$1.60	$ .94
Cumulative effect of change in accounting principle	$ -	$ -	$ -	$(.01)
Basic earnings per common share	$ .53	$ .33	$1.60	$ .93
Diluted earnings per share before accounting change	$ .52	$ .31	$1.56	$ .91
Cumulative effect of change in accounting principle	$ -	$ -	$ -	$(.01)
Diluted earnings per share	$ .52	$ .31	$1.56	$ .90

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, 2004 and 2003
(Unaudited)

	2004	2003
Cash flows from operating activities:		
Net income	$25,744,100	$14,629,600
Adjustments to net income to reconcile to cash provided by operating activities:		
Deferred federal income taxes	8,590,500	4,893,200
Depreciation, depletion & amortization	13,589,800	10,632,400
Cumulative effect of change in accounting principle	-	198,600
Accretion of asset retirement obligation	28,000	27,000
Gain from sale of assets	(5,300)	(144,200)
Leasehold acreage expired or surrendered	291,000	1,364,300
Amortization of stock award	2,800	4,100
Increase in current assets	(3,301,300)	(7,066,100)
(Increase) decrease in other assets	(161,800)	2,087,300
Decrease in current liabilities	(15,078,500)	(8,746,600)
Increase (decrease) in other liabilities	562,000	(1,625,200)
Total adjustments	4,517,200	1,624,800
Net cash provided by operating activities	30,261,300	16,254,400
Cash flows from investing activities:		
Capital expenditures	(26,458,100)	(48,194,500)
Proceeds from sale of leases to partnerships	1,178,800	1,040,800
Proceeds from sale of fixed assets	68,900	162,000
Net cash used in investing activities	(25,210,400)	(46,991,700)
Cash flows from financing activities:		
Net (retirement of) proceeds from long-term debt	(26,000,000)	21,000,000
Proceeds from stock option exercises	2,178,600	-
Repurchase and cancellation of treasury stock	(2,749,100)	(748,700)
Net cash (used in) provided by financing activities	(26,570,500)	20,251,300
Net decrease in cash and cash equivalents	(21,519,600)	(10,486,000)
Cash and cash equivalents, beginning of period	80,379,300	51,023,500
Cash and cash equivalents, end of period	$58,859,700	$ 40,537,500

See accompanying notes to unaudited condensed consolidated financial statements.

1. Accounting Policies

Reference is hereby made to the Company's Annual Report on Form 10-K for 2003, 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.

2. Stock Compensation

The Company has adopted SFAS No. 123, "Accounting for Stock-Based Compensation." SFAS 123 allows entities to continue to measure compensation cost for stock-based awards using the intrinsic value based method of accounting prescribed by APB Opinion No. 25, "Accounting for Stock Issued to Employees," and to provide pro forma net income and pro forma earnings per share disclosures as if the fair value based method defined in SFAS 123 had been applied. The Company has elected to continue to apply the provisions of APB 25 and provide the pro forma disclosure provisions of SFAS 123. For stock options granted, the option price was not less than the market value of shares on the grant date, therefore, no compensation cost has been recognized. No options were granted during the nine months ended September 30, 2004 or September 30, 2003. All options were fully vested prior to January 1, 2003. Had compensation cost been determined under the fair value provisions of SFAS 123, the Company's net income and earnings per share would have been the following on a pro forma basis:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
Net income, as reported	$8,691,600	$5,203,900	$25,744,100	$14,629,600
Deduct total stock-based employee compensation expense determined under fair-value-based method for all rewards, net of tax	-	-	-	-
Pro forma net income	$8,691,600	$5,203,900	$25,744,100	$14,629,600
Basic earnings per share as reported	$ .53	$ .33	$1.60	$ .93
Pro forma basic earnings per share	$ .53	$ .33	$1.60	$ .93
Diluted earnings per share as reported	$ .52	$ .31	$1.56	$ .90
Pro forma diluted earnings per share	$ .52	$ .31	$1.56	$ .90

3. Basis of Presentation

The Management of the Company believes that all adjustments (consisting of only normal recurring accruals) necessary to a fair statement of the results of such periods have been made. The results of operations for the nine months ended September 30, 2004 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
Weighted average common shares outstanding	16,284,827	15,636,787	16,140,358	15,670,092
Weighted average common and common equivalent shares outstanding	16,694,637	16,294,616	16,542,623	16,186,849
Net income before cumulative effect of change in accounting principle	$8,691,600	$ 5,203,900	$25,744,100	$14,828,200
Cumulative effect of change in accounting principle (net of taxes of $121,700)	-	-	-	(198,600)
Net income	$8,691,600	$5,203,900	$25,744,100	$14,629,600
Basic earnings per common share before accounting change	$ .53	$ .33	$ 1.60	$.94
Cumulative effect of change in accounting principle	$ -	$ -	$ -	$(.01)
Basic earnings per common share	$ .53	$ .33	$ 1.60	$ .93
Diluted earnings per share before accounting change	$ .52	$ .31	$ 1.56	$ .91
Cumulative effect of change in accounting principle	$ -	$ -	$ -	$(.01)
Diluted earnings per share	$ .52	$ .31	$ 1.56	$ .90

6. Supplemental Disclosure of Non-Cash Financing Activities

The Company received stock with a value of $1,408,350 from certain employees upon exercise of employee stock options. The Company also received a current tax benefit of approximately $3 million related to the exercising of stock options. The benefit was recorded as an increase in additional paid in capital and a decrease in current taxes payable.

7. Business Segments (Thousands)

The Company'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 2,600 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. Segment information for the three and nine months ended September 30, 2004 and 2003 is as follows: (All numbers presented below are in thousands.)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
REVENUES				
Drilling and Development	$30,394	$14,080	$89,348	$47,444
Natural Gas Marketing	23,983	17,686	73,452	56,645
Oil and Gas Sales	16,117	13,088	48,172	32,866
Well Operations and Pipeline Income	2,074	1,865	5,824	5,282
Unallocated amounts (1)	589	489	1,334	1,158
Total	$73,157	$47,208	$218,130	$143,395

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
SEGMENT INCOME BEFORE INCOME TAXES				
Drilling and Development	$4,389	$ 2,124	$13,019	$7,692
Natural Gas Marketing	1	116	962	361
Oil and Gas Sales	8,947	6,189	25,966	15,630
Well Operations and Pipeline Income	965	721	2,846	2,172
Unallocated amounts (2)				
General and Administrative expenses	(926)	(1,378)	(2,821)	(3,742)
Interest expense	(252)	(415)	(751)	(911)
Other (1)	497	410	1,039	930
Total	$13,621	$ 7,767	$40,260	$ 22,132

	September 30, 2004	December 31, 2003
SEGMENT ASSETS		
Drilling and Development	$44,825	$ 62,546
Natural Gas Marketing	22,291	17,006
Oil & Gas Sales	204,251	204,849
Well Operations and Pipeline Income	17,344	11,602
Unallocated amounts		
Cash	1,847	800
Other	12,375	9,919
Total	$302,933	$306,722

(1) Includes 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.

8. Comprehensive Income

Comprehensive income includes net income and certain items recorded directly to shareholders' equity and classified as Other Comprehensive Income. The following table illustrates the calculation of comprehensive income for the nine months ended September 30, 2004 and 2003.

	2004	2003
Net Income before cumulative effect of change in accounting principle	$ 25,744,100	$ 14,828,200
Cumulative effect on prior years of SFAS 143 - "Accounting for Asset Retirement Obligations" (net of taxes of $121,700)	-	(198,600)
Net income	25,744,100	14,629,600
Other Comprehensive Income (loss) (net of tax):		
Reclassification adjustment for settled contracts included in net income (net of tax of $106,600, and $603,200, respectively)	167,500	984,100
Change in fair value of outstanding hedging positions (net of tax of $ 2,585,000 and $108,000, respectively)	(4,060,200)	(176,200)
Other Comprehensive Income (loss)	(3,892,700)	807,900
Comprehensive Income	$21,851,400	$15,437,500

9. 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 hedging instruments or the counterparties to the Company's gas marketing contracts not perform. Such nonperformance is not anticipated. There were no counterparty default losses in the first three quarters of 2004 or the year 2003.

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 investors, is currently approximately $6.3 million. The Company believes it has adequate liquidity to meet this obligation.

The Company is not party to any legal action that would materially affect the Company's results of operations or financial condition.

10. Common Stock Repurchase

On March 13, 2003 the Company publicly announced the authorization by its Board of Directors to repurchase up to 5% of the Company's common stock (785,000 shares) at fair market value at the date of purchase. 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, 2004. The following activity has occurred since inception of the plan on March 13, 2003 until September 30, 2004.

Month of Purchase	March, 2003	April, 2003	September, 2003
Average Price paid per share	$6.08	$6.48	$11.15
Broker/Dealer	McDonald Investments	McDonald Investments	McDonald Investments
Number of Shares Purchased	46,500	49,900	12,800
Remaining Number of Shares to Purchase	738,500	688,600	675,800

In addition to the stock repurchase program discussed above the Company purchased the following shares:

During the quarter ended March 31, 2004 the Compensation Committee of the Board of Directors approved a repurchase of 48,650 shares of common stock from one of the Company's officers. The repurchase price of the common stock was the closing price on the date of the repurchase of $26.61 per share and totaled $1,294,600 which approximated the tax savings to be realized by the Company as a result of the exercise of said officer's non-qualified stock options in the first quarter of 2004. Such treasury stock was subsequently cancelled.

During the quarter ended June 30, 2004 the Company repurchased 50,487 shares from the estate of one of the Company's former officers in accordance with terms of the former officer's employment agreement. The repurchase price of the stock was $27.73 per share (the 90-day average prior to the repurchase per contract). The repurchase totaled $1,400,000 of which $1,000,000 was funded by life insurance proceeds. The life insurance proceeds were recorded as other income in the fourth quarter of 2003. The Company also repurchased 1,703 shares from an employee upon retirement from the Company. Such treasury stock was subsequently cancelled.

11. Change in Accounting Principle

In June 2001, the Financial Accounting Standards Board issued SFAS No. 143, "Accounting for Asset Retirement Obligations" that requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. This statement is effective for fiscal years beginning after June 15, 2002. The Company adopted SFAS No. 143 on January 1, 2003 and recorded a net asset of $271,800 and a related liability of $592,100 (using a 6% discount rate) and a cumulative effect of change in accounting principle on prior years of $198,600 (net of income taxes of $121,700).

12. Acquisition of Oil and Gas Properties

During the second quarter of 2003 the Company completed the purchase of natural gas properties in the Denver-Julesburg Basin in northeastern Colorado for $28 million from Williams Production RMT Company, a subsidiary of The Williams Companies, Inc. of Tulsa, OK. The effective date of the purchase was April 1, 2003. Funding for the acquisition was provided from the Company’s bank credit facility with Bank One N.A. and BNP Paribas.

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

Overview

The Company has recorded historically strong revenues, income and cash flow for both the third quarter and the first nine months of 2004. 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 both for sales of Company-owned production and for gas purchased and sold by Riley Natural Gas, our natural gas marketing subsidiary. 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, revenues and profits 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. Similarly higher oil and natural gas prices also increased the cost of purchasing gas for resale in the Company's gas marketing unit.

The increased profitability and cash flow from operations allowed the company to reduce its long term debt and to continue to invest in capital projects. The majority of the capital investment was for oil and gas drilling and development activities. The Company also constructed an office building in Colorado for the Company's field operations in the area.

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, 2004 Compared with September 30, 2003

Revenues

Total revenues for the three months ended September 30, 2004 were $73.2 million compared to $47.2 million for the three months ended September 30, 2003, an increase of approximately $26.0 million or 55.1 percent. Such increase was a result of increased drilling revenues, sales from gas marketing activities, oil and gas sales and well operations and pipeline income.

Drilling Revenues

Drilling revenues for the three months ended September 30, 2004 were $30.4 million compared to $14.1 million for the three months ended September 30, 2003, an increase of approximately $16.3 million or 115.6 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 2004 with advances for future drilling from June 30, 2004 of $23.4 million compared with advances for future drilling of $12.9 million at the beginning of the third quarter of 2003. During the third quarter of 2004 the Company funded two drilling program partnerships with total subscriptions of $36.0 million compared to one program funded during the third quarter of 2003 for $17.3 million. These programs commenced drilling operations shortly after funding. 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.

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, 2004 were $24.0 million compared to $17.7 million for the three months ended September 30, 2003, an increase of approximately $6.3 million or 35.6 percent. Such increase was due to higher volumes of natural gas sold and higher average sales prices.

Oil and Gas Sales

Oil and gas sales from the Company's producing properties for the three months ended September 30, 2004 were $16.1 million compared to $13.1 million for the three months ended September 30, 2003 an increase of $3.0 million or 22.9 percent. The increase was due to increased volumes sold at higher average sales prices of oil and natural gas. The volume of natural gas sold for the three months ended September 30, 2004 was 2.6 million Mcf at an average sales price of $5.08 per Mcf compared to 2.4 million Mcf at an average sales price of $4.55 per Mcf for the three months ended September 30, 2003. Oil sales were 88,000 barrels at an average sales price of $33.66 per barrel for the three months ended September 30, 2004 compared to 80,000 barrels at an average sales price of $28.42 per barrel for the three months ended September 30, 2003. The increase in natural gas volumes was the result of the Company's increased investment in oil and gas properties, recompletions of existing wells, two fourth quarter 2003 acquisitions of oil and gas properties in Colorado and Kansas and the investment in oil and gas properties we own in our public drilling program partnerships.

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, 2004			Three Months Ended September 30, 2003		
	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)
Appalachian Basin	1,589	458,657	468,191	1,121	485,968	492,694
Michigan Basin	1,301	445,013	452,819	1,616	449,457	459,153
Rocky Mountains	85,414	1,682,360	2,194,844	77,367	1,442,556	1,906,758
Total	88,304	2,586,030	3,115,854	80,104	2,377,981	2,858,605
Average Price	$33.66	$5.08	$5.17	$28.42	$4.55	$4.58

Our financial results depend upon many factors, particularly the price of natural gas and our ability to market our production on economically attractive terms. Price volatility in the natural gas and oil markets has remained prevalent in the last few years and can have a material impact on our financial results. Natural gas prices declined dramatically at the end of 2001 and during the entire first quarter of 2002. However, in the second quarter of 2002, the Company saw a significant strengthening of natural gas prices in its Appalachian and Michigan producing areas. Natural gas prices in Colorado remained low for most of 2002. In the fourth quarter of 2002 and continuing in 2003 and 2004, Colorado prices began to increase, although they continue to trail prices in other areas. The Company 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. On May 1st of 2003, the Kern River pipeline expansion was completed and placed into service. The Kern River Pipeline Company has announced that the additional facilities added about 900 million cubic feet per day of capacity for deliveries to Arizona, Nevada and southern California. This represents almost 30% of the prior pipeline capacity from the region to the West Coast and other markets outside the region. The Company believes that the completion and start-up of the pipeline eliminated or reduced the local supply surplus, leading to improved natural gas prices in the region. Since the startup of the new Kern River pipeline the Colorado Interstate Gas price index has improved to a range of from 78% to 91% for an average of 86% of the NYMEX price, levels consistent with historical price relationships before the local demand/pipeline capacity problem. The Company has commodity price hedging contracts for oil and natural gas production from October 2004 through December 2005 to protect against possible short-term price weaknesses.

Oil and Gas Hedging Activities

Because of uncertainty surrounding natural gas prices we have used various hedging instruments to manage some of the impact of fluctuations in prices. Through December of 2005 we have in place a series of floors and ceilings and hedges 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, 2004 the Company averaged natural gas volumes sold of 862,000 Mcf per month and oil sales of 29,400 barrels per month. The current positions in effect on the Company's share of production are shown in the following table.

		Floors		Ceilings	
Month Set	Month	Monthly Quantity Mmbtu	Contract Price	Monthly Quantity Mmbtu	Contract Price
	NYMEX Based Hedges - (Appalachian and Michigan Basins)				
1/04	Oct 2004	122,000	$5.00	-	-
10/03	Oct 2004	81,000	$4.00	81,000	$5.65
5/04	Nov 2004 - Mar 2005	180,000	$5.67	90,000	$7.00
2/04	Apr 2005 - Oct 2005	122,000	$4.28	61,000	$5.00
	Rocky Mountain Region				
	Colorado Interstate Gas (CIG) Based Hedges (Piceance Basin)				
10/03	Oct 2004	25,000	$3.20	25,000	$4.70
1/04	Oct 2004	25,000	$4.17	-	-
5/04	Nov 2004 - Mar 2005	60,000	$5.04	30,000	$6.00
2/04	Apr 2005- Oct 2005	33,000	$3.10	16,000	$4.43
	Colorado Interstate Gas (CIG) Based Hedges (Wattenberg Field)				
7/04	Nov 2004 - Mar 2005	80,000	$5.00	40,000	$6.20
	NYMEX Based Hedges (NECO)				
6/03	Oct 2004 - Dec 2004	150,000	$4.50	-	-
7/04	Jan 2005 - Mar 2005	150,000	$5.32	-	-
2/04	Apr 2005 - Oct 2005	150,000	$4.26	75,000	$5.00
	Oil hedges (Wattenberg Field)				
	Month	Monthly Quantity barrels	Contract Price		
2/04	Oct 2004 - Dec 2004	10,000	$31.63	-	-
		Floors		Ceilings	
8/04	Jan 2005 - Dec 2005	15,000	$32.30	7,500	$40.00

Well Operations, Pipeline and Other Income

Well operations and pipeline income for the three months ended September 30, 2004 was $ 2.1 million compared to $1.9 million for the three months ended September 30, 2003, an increase of approximately $200,000 or 10.5 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 for the three months ended September 30, 2004 was $589,000 compared to $488,000 for the three months ended September 30, 2003.

Costs and Expenses

Costs and expenses for the three months ended September 30, 2004 were $59.5 million compared to $39.4 million for the three months ended September 30, 2003, an increase of approximately $20.1 million or 51.0 percent. Such increase was primarily the result of increased cost of oil and gas well drilling operations, cost of gas marketing activities, and depreciation, depletion and amortization.

Oil and Gas Well Drilling Operations Costs

Oil and gas well drilling operations costs for the three months ended September 30, 2004 were $26.0 million compared to $12.0 million for the three months ended September 30, 2003, an increase of approximately $14.0 million or 116.7 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, 2004 was 14.4% compared with 15.1% for the three months ended September 30, 2003, a decrease in gross margin of 0.7%. Such decrease was due to increasing well drilling costs particularly the cost of well fracturing and rising steel costs for casing and other well equipment. For competitive reasons, the company does not plan to increase charges to its investor partners at this time and as a result anticipates a continuation of lower margins in 2004 compared to the prior year.

Cost of Gas Marketing Activities

The costs of gas marketing activities for the three months ended September 30, 2004 were $24.0 million compared to $17.5 million for the three months ended September 30, 2003, an increase of $6.5 million or 37.1 percent. The increase was due to 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 was approximately a break even for the three months ended September 30, 2004 compared to an income before income taxes of $116,000 for the three months ended September 30, 2003. Based on the nature of the Company's gas marketing activities, hedging did not have a significant impact on the Company's net margins from marketing activities during either period.

Oil and Gas Production Costs

Oil and gas production costs from the Company's producing properties remained approximately the same at $4.0 million for both periods. Lifting cost per Mcfe increased from $1.01 per Mcfe during the three months ended September 30, 2003 to $1.10 per Mcfe during the three months ended September 30, 2004, primarily as a result of production taxes on higher average prices of gas and oil sold. These lifting cost increases were offset by other production cost declines.

General and Administrative Expenses

General and administrative expenses for the three months ended September 30, 2004 were $926,000, compared to $1.4 million for the three months ended September 30, 2003, a decrease of approximately $474,000, or 33.9 percent. Such decrease was due to the change of and restructuring of executives' compensation offset in part by increased administrative activity associated with an expanding Company.

Depreciation, Depletion, and Amortization

Depreciation, depletion, and amortization costs for the three months ended September 30, 2004 increased to $4.4 million from approximately $4.2 million for the three months ended September 30, 2003, an increase of approximately $200,000 or 4.8 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, 2004 was $253,000 compared to $415,000 for the three months ended September 30, 2003, a decrease of $162,000 or 39.0 percent. Such decrease was due to lower average outstanding balances of our credit facility offset in part by higher interest rates. The Company utilizes its daily cash balances to reduce its line of credit to lower its costs of interest. The average outstanding debt balance for the three months ended September 30, 2004 was $11.4 million compared to $36.1 million for the three months ended September 30, 2003.

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes increased from approximately 33 percent to 36.2 percent primarily as a result of the application of higher tax rates due to significantly increased earnings of the Company during 2004 and other miscellaneous permanent differences which are not expected in 2004.

Net income and Earnings Per Share

Net income for the three months ended September 30, 2004 was $8.7 million compared to a net income of $5.2 million for the three months ended September 30, 2003, an increase of approximately $3.5 million or 67.3 percent.

Diluted earnings per share for the three months ended September 30, 2004 was $ .52 per share compared to $ .31 per share for the three months ended September 30, 2003, an increase of $ .21 per share or 67.7 percent.

Nine Months Ended September 30, 2004 Compared with September 30, 2003

Revenues

Total revenues for the nine months ended September 30, 2004 were $218.1 million compared to $143.4 million for the nine months ended September 30, 2003, an increase of approximately $74.7 million or 52.1 percent. Such increase was a result of increased drilling revenues, sales from gas marketing activities, oil and gas sales and well operations and pipeline income.

Drilling Revenues

Drilling revenues for the nine months ended September 30, 2004 were $89.3 million compared to $47.4 million for the nine months ended September 30, 2003, an increase of approximately $41.9 million or 88.4 percent. Such increase was due to the increased drilling funds raised through the Company's Public Drilling Programs. The Company started the year of 2004 with advances for future drilling from December 31, 2003 of $50.5 million compared with advances for future drilling of $37.3 million at the beginning of the year of 2003. During the first nine months of 2004 the Company funded three drilling programs with total subscriptions of $65.0 million compared to funding two drilling program partnerships during the first nine months of 2003 with total subscriptions of $25.8 million. The programs commenced drilling operations shortly after funding. We believe in part that this increase results from higher oil and natural gas prices which have improved the performance of our prior programs helping to increase our current drilling program sales.

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, 2004 were $73.5 million compared to $56.6 million for the nine months ended September 30, 2003, an increase of approximately $16.9 million or 29.9 percent. Such increase was due to higher volumes of natural gas sold, along with higher average sales prices.

Oil and Gas Sales

Oil and gas sales from the Company's producing properties for the nine months ended September 30, 2004 were $48.2 million compared to $32.9 million for the nine months ended September 30, 2003 an increase of $15.3 million or 46.5 percent. The increase was due to significantly increased volumes sold at higher average sales prices of oil and natural gas. The volume of natural gas sold for the nine months ended September 30, 2004 was 7.76 million Mcf at an average sales price of $5.00 per Mcf compared to 6.1 million Mcf at an average sales price of $4.46 per Mcf for the nine months ended September 30, 2003. Oil sales were 288,000 barrels at an average sales price of $32.59 per barrel for the nine months ended September 30, 2004 compared to 195,000 barrels at an average sales price of $28.05 per barrel for the nine months ended September 30, 2003. The increase in natural gas volumes was the result of the Company's increased investment in oil and gas properties, primarily the Williams property acquisition in the second quarter of 2003, recompletions of existing wells, two fourth quarter 2003 acquisitions of oil and gas properties in Colorado and Kansas and the investment in oil and gas properties we own in our public drilling program partnerships.

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, 2004			Nine Months Ended September 30, 2003		
	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)
Appalachian Basin	3,931	1,346,915	1,370,501	3,135	1,459,414	1,478,224
Michigan Basin	4,305	1,314,829	1,340,659	4,910	1,382,532	1,411,992
Rocky Mountains	280,308	5,093,748	6,775,596	187,194	3,297,830	4,420,994
Total	288,544	7,755,492	9,486,756	195,239	6,139,776	7,311,210
Average Price	$32.59	$5.00	$5.08	$28.05	$4.46	$4.50

Our financial results depend upon many factors, particularly the price of natural gas and our ability to market our production on economically attractive terms. Price volatility in the natural gas and oil markets has remained prevalent in the last few years and can have a material impact on our financial results. Natural gas prices declined dramatically at the end of 2001 and during the entire first quarter of 2002. However, in the second quarter of 2002, the Company saw a significant strengthening of natural gas prices in its Appalachian and Michigan producing areas. Natural gas prices in Colorado remained low for most of 2002. In the fourth quarter of 2002 and continuing in 2003 and 2004, Colorado prices began to increase, although they continue to trail prices in other areas. The Company 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. On May 1st of 2003, the Kern River pipeline expansion was completed and placed into service. The Kern River Pipeline Company has announced that the additional facilities added about 900 million cubic feet per day of capacity for deliveries to Arizona, Nevada and southern California. This represents almost 30% of the prior pipeline capacity from the region to the West Coast and other markets outside the region. The Company believes that the completion and start-up of the pipeline eliminated or reduced the local supply surplus, leading to improved natural gas prices in the region. Since the startup of the new Kern River pipeline the Colorado Interstate Gas price index has improved to a range of from 83% to over 90% of the NYMEX price, levels consistent with historical price relationships before the local demand/pipeline capacity problem. The Company has commodity price hedging contracts for oil and natural gas production from October 2004 through December 2005 to protect against possible short-term price weaknesses. See Management's Discussion and Analysis for the three months ended September 30, 2004 compared with September 30, 2003 for a complete schedule of current hedging positions.

Well Operations, Pipeline and Other Income

Well operations and pipeline income for the nine months ended September 30, 2004 was $5.8 million compared to $5.3 million for the nine months ended September 30, 2003, an increase of approximately $500,000 or 9.4 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 for the nine months ended September 30, 2004 was $1.3 million compared to $1.2 million for the nine months ended September 30, 2003.

Costs and Expenses

Costs and expenses for the nine months ended September 30, 2004 were $177.9 million compared to $121.3 million for the nine months ended September 30, 2003, an increase of approximately $56.6 million or 46.7 percent. Such increase was primarily the result of increased cost of oil and gas well drilling operations, cost of gas marketing activities, oil and gas production costs and depreciation, depletion and amortization.

Oil and Gas Well Drilling Operations Costs

Oil and gas well drilling operations costs for the nine months ended September 30, 2004 were $76.3 million compared to $39.8 million for the nine months ended September 30, 2003, an increase of approximately $36.5 million or 91.7 percent. Such increase was due to the higher levels of drilling activity from our Public Drilling Programs referred to above. In addition, the gross margin on the drilling activities for the nine months ended September 30, 2004 was 14.6% compared with 16.2% for the nine months ended September 30, 2003, a decrease in gross margin of 1.6%. Such decrease was due to increasing well drilling costs particularly the cost of well fracturing and rising steel costs for casing and other well equipment. For competitive reasons the company does not plan to increase charges to its investor partners at this time and as a result anticipates a continuation of lower margins in 2004 compared to the prior year.

Cost of Gas Marketing Activities

The cost of gas marketing activities for the nine months ended September 30, 2004 was $72.5 million compared to $55.9 million for the nine months ended September 30, 2003, an increase of $16.6 million or 29.7 percent. The increase was due to 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 improved from $361,000 for the nine months ended September 30, 2003 to $962,000 for the nine months ended September 30, 2004. Based on the nature of the Company's gas marketing activities, hedging did not have a significant impact on the Company's net margins from marketing activities during either period.

Oil and Gas Production Costs

Oil and gas production costs from the Company's producing properties for the nine months ended September 30, 2004 were $11.9 million compared to $10.3 million for the nine months ended September 30, 2003, an increase of approximately $1.6 million or 15.5 percent. Such increase was due to the increased production costs on the increased volumes 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 $0.99 per Mcfe during the nine months ended September 30, 2003 to $1.03 per Mcfe during the nine months ended September 30, 2004.

General and Administrative Expenses

General and administrative expenses for the nine months ended September 30, 2004 were $2.8 million compared to $3.7 million for the nine months ended September 30, 2003, a decrease of approximately $900,000 or 24.3 percent. Such decrease was due to the change of and restructuring of executives' compensation offset in part by increased administrative activity associated with an expanding Company.

Depreciation, Depletion, and Amortization

Depreciation, depletion, and amortization costs for the nine months ended September 30, 2004 increased to $13.6 million from approximately $10.6 million for the nine months ended September 30, 2003, an increase of approximately $3.0 million or 28.3 percent. Such increase was due to the significantly increased production and investment in oil and gas properties by the Company.

Interest Expense

Interest costs for the nine months ended September 30, 2004 was $751,000 compared to $911,000 for the three months ended September 30, 2003, a decrease of $160,000 or 17.6 percent. Such decrease is due to lower average outstanding balances of our credit facility offset in part by higher interest rates. The Company utilizes its daily cash balances to reduce its line of credit to lower its cost of interest. The average outstanding debt balance for the nine months ended September 30, 2004 was $11.9 million compared to $20.6 million for the nine months ended September 30, 2003.

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes increased from approximately 33 percent to 36.1 percent primarily as a result of the application of higher tax rates due to significantly increased earnings of the Company during 2004 and other miscellaneous permanent differences which are not expected in 2004.

Net income and Earnings Per Share

Net income for the nine months ended September 30, 2004 was $25.7 million compared to a net income of $14.6 million for the nine months ended September 30, 2003, an increase of approximately $11.1 million or 76.0 percent.

Diluted earnings per share for the nine months ended September 30, 2004 was $1.56 per share compared to $0.90 per share for the nine months ended September 30, 2003, an increase of $.66 per share or 73.3 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, well drilling and operating activities from the Company's public drilling programs, 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.

Natural Gas Pricing and Pipeline Capacity

Natural gas and oil prices have been volatile in the past, and the Company anticipates continued volatility in the future. Currently, the NYMEX futures reflect a market expectation of continuing strong natural gas prices at Henry Hub. Although prices look strong for the remainder of 2004, natural gas storage levels are above normal levels following a period when storage levels had been at five-year lows. The Company believes this situation creates the possibility of periods of both low prices and continued high prices.

Natural gas prices declined dramatically at the end of 2001 and during the entire first quarter of 2002. However, in the second quarter of 2002, the Company saw a significant strengthening of natural gas prices in its Appalachian and Michigan producing areas. Natural gas prices in Colorado remained low for most of 2002. In the fourth quarter of 2002 and continuing in 2003 and 2004, Colorado prices began to increase, although they continue to trail prices in other areas. The Company 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. On May 1st of 2003, the Kern River pipeline expansion was completed and placed into service. The Kern River Pipeline Company has announced that the additional facilities added about 900 million cubic feet per day of capacity for deliveries to Arizona, Nevada and southern California. This represents almost 30% of the prior pipeline capacity from the region to the West Coast and other markets outside the region. The Company believes that the completion and start-up of the pipeline eliminated or reduced the local supply surplus, leading to improved natural gas prices in the region. Since the startup of the new Kern River pipeline the Colorado Interstate Gas price index has improved to a range of from 83% to over 90% of the NYMEX price, levels consistent with historical price relationships before the recent local demand/pipeline capacity problem.

Oil and Gas Hedging Activities

Because of the uncertainty surrounding natural gas and oil prices we have used various hedging instruments to manage some of the impact of fluctuations in gas prices. Through December 2005 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 current hedging positions.

The Company hedges prices 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.

Oil Pricing

Oil prices have strengthened since the middle of 2003. While oil prices are influenced by supply and demand, global geopolitics may be the single most important determinant. Since the percentage of the Company's production reflected by oil sales has increased to approximately 20% during the nine months of 2004, variations in oil prices will have a greater impact on the Company than in the past. See previous pages in this Management's Discussion and Analysis for a complete schedule of current hedging positions.

Public Drilling Programs

The Company's four drilling program partnerships of 2004 have now all been funded ahead of schedule and earlier than in 2003.

The following is a summary of the partnerships funded during 2004 and 2003:

	2004		2003	
Partnership	Amount	Month Closed	Amount	Month Closed
A - Partnership	$29.0 million	April	$ 8.5 million	April
B - Partnership	$18.0 million	July	$17.3 million	September
C - Partnership	$18.0 million	August	$17.5 million	November
D - Partnership	$35.0 million	October	$35.0 million	December
Total	$100.0 million		$78.3 million	

The Company will open its first 2005 Partnership, the PDC 2005-A Limited Partnership on January 3, 2005 with maximum allowable subscriptions of $40.0 million and a scheduled closing date of February 28, 2005. At this time the Company plans to offer for sale $115 million of partnership interests during 2005.

The Company posts daily the amount of subscriptions that have been sold in the current partnership at its website, www.petd.com, under the heading of "Drilling Program".

The Company invests, as its equity contribution to each drilling partnership, an additional sum of 22% of the aggregate investor subscriptions received for that particular drilling partnership. As a result, the Company is subject to substantial cash commitments at the closing of each drilling partnership. No assurance can be made that the Company will continue to receive recent levels of funding from future programs.

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 $6.3 million. The Company has adequate liquidity to meet this obligation. During the first nine months of 2004 the Company has spent $347,400 under this provision.

Drilling Activity

Through the first three quarters of 2004 the Company drilled along with its public drilling fund partnerships a total of 103 wells with only one developmental dry hole. The Company drilled 75 successful wells in its Wattenberg field in the Denver-Julesberg Basin and 28 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 2004 partnership drilling activity in these two areas.

In early October 2004, the Company began drilling on a planned 15 well program on its northeast Colorado properties (NECO). The wells are being drilled on locations created by the regulatory approval of a reduction in well spacing from 80 to 40 acres on the properties the Company acquired in Yuma County in 2003. As of October 31, 2004, eleven wells had been drilled and one well had been completed. The Company expects all eleven wells to be productive based on the results of logs and other data.

On August 16, 2004, the Company began drilling the Fox Federal 1-13 well in Moffat County, Colorado. This well is an exploratory well to test the Mesaverde formation in the western Sand Wash Basin. The well was drilled to its planned total depth of 12,778 feet on October 27th and pipe has been run for a planned completion in the target zone. The Company accounts for its oil and gas properties under the successful efforts method. Under this method the cost of drilling an exploratory well is capitalized pending determination of whether the well has discovered economically producible reserves. If such reserves are not discovered the costs are expensed as a dry hole. The cost to date on this well is approximately $2.5 million. Both the NECO and the exploratory test well are being funded by the Company’s capital budget without partnership participation.

Common Stock Repurchase Program

On March 13, 2003 the Company publicly announced a common stock repurchase program to repurchase up to 5% of the Company's outstanding common stock (785,000 shares) expiring on December 31, 2004. From inception of the program until September 30, 2004, the Company has repurchased 109,200 shares at an average price of $6.86 per share. The Company intends to fund this repurchase of common stock through internally generated cash flow.

Long-Term Debt

The Company has a credit facility with J. P. Morgan (formerly Bank One, NA) and BNP Paribas of $100 million subject to adequate oil and natural gas reserves. Currently the borrowing base is set at $80 million while the Company's total oil and gas reserves calculated under this method is in excess of $100 million. As of September 30, 2004 the Company had activated $60 million of this facility. As of September 30, 2004, the outstanding balance on the line of credit was $27.0 million of which $10.0 million was subject to an interest rate swap at a rate of 8.39% and $17.0 million was subject to a prime rate of 4.75%. The above interest rate swap expired on October 12, 2004 at which time the Company will benefit from lower effective interest rate on $10 million of its outstanding credit balance. The line of credit is at prime, with LIBOR alternatives available at the discretion of the Company. No principal payments are required until the credit agreement expires. In the second quarter of 2004, the banks and the Company extended the expiration date of the credit agreement until July 3, 2008.

Contractual Obligations

Contractual obligations and due dates are as follows:

Payments due by period

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-Term Debt	$27,000,000	$ -	$ -	$27,000,000	$ -
Operating Leases	590,000	215,300	261,500	113,200	-
Asset Retirement Obligation	758,200	-	50,000	50,000	658,200
Other Liabilities	3,011,100	115,000	230,000	230,000	2,436,100
Total	$31,359,300	$330,300	$541,500	$27,393,200	$3,094,300

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 62 public partnerships, the Company has liability for any potential casualty losses in excess of the partnership assets and insurance. 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 on the first of 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 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 hedging activities could result in reduced revenue compared to the level the Company would experience if no hedges were in place. The Company uses hedges to reduce the impact of price movements on revenue. While these hedges 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.

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. Our critical accounting policies and estimates are as follows:

Revenue Recognition

We recognize revenue from drilling contracts using the percentage-of-completion method based upon costs incurred to date compared to our estimate of the total contract costs. Under percentage-of-completion, we make estimates of the total contract costs to be incurred, and to the extent these estimates change, the amount of revenue recognized could be affected. Anticipated losses, if any, on uncompleted contracts are recorded at the time our estimated costs exceed the contract revenue. The Company has not experienced any contract losses for any periods presented in these financial statements.

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.

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.

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.

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 and hedging activities are complex; interpretation of these requirements by standard-setting bodies is ongoing.

Derivatives are reported on the Condensed Consolidated Balance Sheets at fair value. Changes in fair value of derivatives that are not designated as accounting hedges are recorded in earnings.

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. In addition, for hedges of forecasted transactions, the Company must estimate the expected future cash flows of the forecasted transactions, as well as evaluate the probability of the occurrence and timing of such transactions. Changes in conditions or the occurrence of unforeseen events could affect the timing of recognition in earnings for changes in fair value of certain hedging derivatives.

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.

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

Depreciation, Depletion and Amortization

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

Costs of proved properties including leasehold acquisition, exploration and development costs and equipment are depreciated or depleted by the unit-of-production method based on estimated proved developed oil and gas reserves.

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 is not expected to be realized, a valuation 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. See additional discussions in this Management's Discussion and Analysis.

New Accounting Standards

In June 2001, the Financial Accounting Standard Board issued SFAS No. 143, "Accounting for Asset Retirement Obligations" that required entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. This statement was effective for fiscal years beginning after June 15, 2002. The Company adopted SFAS No. 143 on January 1, 2003 and recorded a net asset of $271,800 and a related liability of $592,100 (using a 6% discount rate) and a cumulative effect of change in accounting principle on prior years of $198,600 (net of taxes of $121,700).

In December 2002, the FASB issued SFAS 148, "Accounting for Stock-Based Compensation - Transition and Disclosure", an amendment of FASB Statement No. 123. This statement amended SFAS No. 123, Accounting for Stock-Based Compensation, to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this statement amended the disclosure requirements of SFAS 123 to require prominent disclosures in both annual and interim financial statements. Disclosures required by this standard are included in the notes to these financial statements.

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.

Recently Issued Accounting Pronouncements

We have been made aware of an issue regarding the application of provisions of Statement of Financial Accounting Standards (SFAS) 141, "Business Combinations" and SFAS 142, "Goodwill and Other Intangible Assets," to companies in the extractive industries, including oil and gas companies. The issue was whether SFAS 142 requires registrants to reclassify cost associated with mineral rights, including both proved and unproved leasehold acquisition costs, as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs. Historically, the Company and other oil and gas companies have included the cost of these oil and gas leasehold interests as part of oil and gas properties and provided the disclosures required by SFAS 69, "Disclosures about Oil and Gas Producing Activities."

Also under consideration was whether SFAS 142 requires registrants to provide the additional disclosure for intangible assets for costs associated with mineral rights. This issue as it pertains to oil and gas companies was referred to the FASB staff, and the staff issued a proposed FASB Staff Position ("FSP") on the matter on July 19, 2004. On September 2, 2004, the FASB issued FSP 142.2, "application of FASB Statement No. 142, Goodwill and Other Intangible Assets, to Oil- and Gas- Producing Entities," which concluded that the scope exception in paragraph 8(b) of Statement 142 extends to the balance sheet classification and disclosure provisions for drilling and mineral rights of oil- and gas- producing entities. Therefore, there are no balance sheet reclassifications or additional disclosure requirements necessary.

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 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 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, 2003.

Commodity Price Risk

The Company sells its natural gas and oil subject to market sensitive contracts, the price of which may greatly increase or decrease with market forces beyond our control. The NYMEX monthly closing price for natural gas during 2004 has ranged from $5.08 per Mmbtu to $7.63 per Mmbtu while oil has ranged from $33.02 per Bbl to $54.92 per Bbl during the same period. The average NYMEX closing price for natural gas for the years 2003 and 2002 was $5.39 Mmbtu and $3.22 Mmbtu, the average NYMEX closing price for oil for the years 2003 and 2002 was $30.98 bbl and $26.98 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.

The Company utilizes commodity-based derivative instruments as hedges 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. These hedging arrangements 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 hedge relates and, in the case of RNG, the cost of gas supplies purchased for marketing activities. As a result, while these hedging arrangements are structured to reduce the Company's exposure to changes in price associated with the hedged commodity, they also limit the benefit the Company might otherwise have received from price changes associated with the hedged 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 futures and options contracts for Riley Natural Gas and PDC as of September 30, 2004 and September 30, 2003.

Riley Natural Gas
Open Futures Contracts

Commodity	Type	Quantity Gas-Mmbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Value
Total Contracts as of September 30, 2004					
Natural Gas	Sale	3,920,000	$5.51	$21,616,540	($5,842,600)
Natural Gas	Purchase	1,150,000	$6.11	$7,029,540	$706,260
Natural Gas	Sale Option	660,000	$5.20		$0
Natural Gas	Purchase Option	330,000	$6.97		($124,075)
Contracts maturing in 12 months following September 30, 2004					
Natural Gas	Sale	2,540,000	$5.69	$14,456,880	($3,295,600)
Natural Gas	Purchase	740,000	$6.03	$4,464,360	$547,890
Natural Gas	Sale Option	580,000	$5.16		$0
Natural Gas	Purchase Option	290,000	$6.96		($124,075)
Prior Year Total Contracts as of September 30, 2003					
Natural Gas	Sale	2,650,000	$4.46	$11,829,480	($969,430)
Natural Gas	Purchase	750,000	$4.70	$3,524,240	$12,030

The maximum term over which RNG is hedging exposure to the variability of cash flows for commodity price risk is 33 months.

Petroleum Development Corporation
Open Futures Contracts

Commodity	Type	Quantity Gas-Mmbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Value
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		$0
Natural Gas	Purchase Option	1,974,075	$5.57		($2,103,011)
Oil	Sale	28,740	$31.63	$909,046	($489,155)
Oil	Sale Option	172,440	$32.30	$5,569,812	$0
Oil	Purchase Option	86,220	$40.00	$3,448,800	($453,086)
Contracts maturing in 12 months following September 30, 2004					
Natural Gas	Purchase	11,679	$4.82	$56,254	$22,202
Natural Gas	Sale Option	4,570,090	$4.68		$0
Natural Gas	Purchase Option	1,815,580	$5.62		($1,876,651)
Oil	Sale	28,740	$31.63	$909,046	($489,155)
Oil	Sale Option	129,330	$32.30	$4,177,359	$0
Oil	Purchase Option	64,665	$40.00	$2,586,600	($391,870)
Prior Year Total Contracts as of September 30, 2003					
Natural Gas	Sale	52,948	$3.80	$201,202	($33,527)
Natural Gas	Sale Option	2,946,920	$4.40	$0	$110,360
Natural Gas	Purchase Option	400,785	$5.18	$0	($134,855)
Oil	Sale	17,802	$30.00	$534,060	$22,431

The maximum term over which PDC is hedging exposure to the variability of cash flows for commodity price risk is 15 months.

Item 4. Controls and Procedures

Under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, the Company has evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Exchange Act Rule 13a-14(c)) as of the end of this fiscal quarter, and, based on their evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these disclosure controls and procedures are effective in all material respects, including those to ensure that information required to be disclosed in reports filed or submitted under the Securities Exchange Act is recorded, processed, summarized, and reported, within the time periods specified in the Commission's rules and forms, and is accumulated and communicated to management, including the Company's Chief Executive Officer and Chief Financial Officer, as appropriate to allow for timely disclosure. There have been no significant changes in our internal control over financial reporting or in other factors that have materially affected or are reasonably likely to materially affect these controls that occurred during the Company's last fiscal quarter and subsequent to the date of their evaluation.

While we believe that we currently have adequate internal control procedures in place, we are still exposed to potential risks from recent legislation requiring companies to evaluate and auditors to attest to management's assertions related to controls under Section 404 of the Sarbanes-Oxley Act of 2002. We are evaluating and further documenting our internal controls systems in order to allow management to report on, and our Registered Independent Public Accounting Firm to attest to, our internal controls, as required by Section 404 of the Sarbanes-Oxley Act. We are currently performing the system and process evaluation and testing required in an effort to comply with the management certification and auditor attestation requirements of Section 404. Due to ongoing evaluation and testing of our internal controls and the uncertainties of the interpretation of these new requirements, there can be no assurance that the process will be completed in the time frame allowed, or that there may not be significant deficiencies or material weaknesses that would be required to be reported.

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. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 4. Submission of Matters to a Vote of Security Holders

None.

Item 6. Exhibits

Exhibit Name	Exhibit Number	Location
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.
Section 1350 Certification by Chief Executive Officer	32.1	Filed herewith.
Section 1350 Certification by Chief Financial Officer	32.2	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: November 4, 2004

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

Date: November 4, 2004

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