PETROLEUM DEVELOPMENT CORP
Form 10-Q/A
December 23, 2005

CONFORMED COPY

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q/A

Amendment No. 1 to Form 10-Q

[X] Quarterly Report Pursuant to Section 13 or 15(d) of

the Securities Exchange Act of 1934

For the period ended March 31, 2005

OR

[ ] Transition Report Pursuant to Section 13 of 15(d) of

the Securities Exchange Act of 1934

For the transition period from ____ to

Commissions 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: 16,589,824 shares of the Company's Common Stock ($.01 par value) were outstanding as of April 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

Overview

As previously reported on Form 10-K/A as filed with the Securities and Exchange Commission on December 13, 2005, the Company identified that certain derivative transactions, certain aspects of the Company's oil and gas property accounting including methods used to calculate depreciation for oil and gas properties and possible impairments of the carrying values of those properties, incorrect adoption of an accounting standard and certain aspects of its income tax provision were accounted for improperly. Accordingly this amendment to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 (the "Form 10-Q") of Petroleum Development Corporation (the "Company") is being filed in order to restate the condensed consolidated financial statements as of March 31, 2005 and 2004 and for the quarters ended March 31, 2005 and 2004 and to make corresponding changes to Item 2, Management's Discussion and Analysis of Financial Condition and Results of Operations, and Item 4, Controls and Procedures. Certain restated prior periods as previously reported on Form 10-K/A for 2004 are reflected in this Form 10-Q/A and noted as restated. See restatement Note 10 on Page 13 of this filing.

This non-cash restatement had the following effect on Net Income:

	Quarter Ended March 31,	
	(Unaudited)	(Unaudited)
(In thousands)	2005	2004
Net income as previously reported	$13,338	$8,439
Adjustments to net income	(2,698)	(733)
Restated net income	$10,640	$7,706

This non-cash restatement had the following effect on Stockholders' Equity:

	As of March 31,	
	(Unaudited)	(Unaudited)
(In thousands)	2005	2004
Stockholders' equity as previously reported	$ 173,818	$ 134,330
Adjustments to Stockholders' equity	(9,040)	(10,576)
Restated Stockholders' equity	$ 164,778	$ 123,754

No attempt has been made in this Form 10-Q/A to update other disclosures presented in the Form 10-Q, except as required to reflect the effects of the restatement. This Form 10-Q/A does not reflect events occurring after the filing to the Form 10-Q or modify or update these disclosures, including exhibits to the Form 10-Q affected by subsequent events. Information not affected by the restatement is unchanged and reflects the disclosures made at the time of the original filing of the Form 10-Q. This Form 10-Q/A includes, however, as Exhibits 31.1, 31.2, and 32.1 new certifications of the Company's Chief Executive Officer and Chief Financial Officer, as required by applicable rules. Accordingly, this Form 10-Q/A should be read in conjunction with the Company's filings made with the Securities and Exchange Commission subsequent to the filing of the Form 10-Q, including any amendments to those filings.

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History of Accounting Issues

Please refer to the Annual Report on Form 10-K/A for the year ended December 31, 2004, for more information.

As a part of its preparation of the financial statements for the quarter ended June 30, 2005, the Company undertook a review of its accounting for oil and gas derivatives. The Company uses derivative instruments as a means of reducing financial exposure to fluctuating oil and gas prices and interest rates. The Company included changes from period to period in the fair value of derivatives classified as cash flow hedges ("Hedges") as increases and decreases to Accumulated Other Comprehensive Income ("AOCI") as allowed by Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("FAS 133"). This Hedge accounting treatment is allowed for certain derivatives, including the types of derivatives used by the Company to reduce exposure to changes in oil and gas prices associated with the sale of oil and gas production and for its natural gas marketing operations and interest rates. In order to qualify for Hedge accounting treatment, specific standards and documentation requirements must be met. The Company believed that its longstanding derivative accounting treatment was permitted under FAS 133. However, after a review of the applicable derivative accounting rules, the Company's accounting policies and documentation of the Company's derivatives, management determined that the Company's derivatives did not qualify for Hedge accounting under FAS 133. The management of the Company reported its determination to the Audit Committee and with the approval of the Committee postponed the filing of its second quarter financial statements until the appropriate accounting could be determined and completed.

In conjunction with the work to correct the Hedge accounting, the Company conducted a thorough review of its financial statements and accounting policies. As a result of the review additional issues were identified that were incorrectly accounted for and needed to be corrected. After determining the impact of the required changes the Company determined that restatements of previously filed financial reports were necessary. These previously filed financial reports should not be relied upon. Descriptions of the errors corrected in this restatement follow:

1. The Company revised its accounting for its derivative transactions, primarily due to the reasons set forth below. The Company used hedge accounting for derivative positions that did not qualify for hedge accounting. These errors began in the first quarter of 2001, the effective date of FAS 133, and continued through the first quarter of 2005.

a. The Company did not have sufficient documentation required for these derivatives to qualify for hedge accounting treatment and did not test them periodically for effectiveness as required by FAS 133.

b. The Company did not record the fair value of certain natural gas purchases and sales contracts which were deemed to be derivatives on its consolidated balance sheet, and changes in fair value were not recorded in earnings.

c. The Company reported the fair value of derivative transactions entered into on behalf of its affiliated partnerships on the balance sheet net of the amount due to/from the partnerships. The fair value of these derivative transactions should have been reported at gross.

2. The Company revised its accounting for oil and gas properties primarily due to the following reasons.

a. The Company's division of its oil and gas properties into fields for calculation of depreciation and depletion and for the determination of impairments was not consistent with applicable rules in FAS 19. According to FAS 19, a field is defined to be "an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition". In accounting for its oil and gas properties, the Company included areas that should have been treated as separate fields as part of a single field. The financial impacts of corrections to divide the Company's oil and gas properties into revised fields were included in the restated financial statements.

b. It was determined that certain policies and procedures the Company followed for calculating quarterly depreciation were incorrect. The Company utilized the previous annual oil and gas reserve reports to estimate quarterly depreciation and adjusted the yearly depreciation based upon the new oil and gas reserve report at the end of the next year. However, each interim period's depreciation must stand on its own and should not be adjusted at the year end upon the issuance of a new oil and gas reserve report. The financial impacts of corrections to calculate each interim period's depreciation on its own were included in the restated financial statements.

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c. The Company also used its proved developed reserves, as defined by Securities and Exchange Commission rules, to calculate depreciation. The Company's proved developed reserves included the anticipated recompletion of the Codell formation in Wattenberg Field in Colorado as well as behind pipe zones in the Appalachian Basin. After reviewing the rules, the Company concluded that both the future estimated costs and the reserves from these "behind pipe reserves" should be excluded in calculating the depreciation amounts. This change resulted in increases in depreciation compared to the method previously used by the Company until the recompletions and behind pipe reserves are completed. The financial impacts of corrections to exclude both the future estimated costs and the reserves from these "behind pipe reserves" in calculating depreciation amounts were included in the restated financial statements.

3. The Company revised its accounting for its asset retirement obligations due to the following reason.

a. The Company interpreted FAS No. 143 as requiring the recording of a liability based on the probable occurrence of certain conditional future events. The Company incorrectly based its estimates of future disposal costs of wells on its historical record of disposing of its wells in ways that transferred asset retirement costs to other parties. The Company has concluded that a liability should be recognized when a legal obligation exists, regardless of conditional future events, and that the full fair value of potential future disposal costs should have been recorded despite the Company's historical practice of transferring most of the obligation to other parties. This error began in the first quarter of 2003, the effective date of FAS No.143, and continued through the first quarter of 2005 and is being corrected through this restatement.

4. The Company revised its accounting for its provision for income taxes in its financial statements due to the following reason.

a. The Company incorrectly determined the portion of the percentage depletion of oil and gas properties for tax purposes which was treated as a permanent difference in the calculation of its tax provision, and incorrectly determined the classification of certain accrued and deferred income tax balances.

During the review and its determination of the magnitude of the errors, management of the Company reported its progress to the Audit Committee, KPMG LLP and to the Board of Directors. On the basis of its analysis of the errors, the management recommended to the Audit Committee and the Board of Directors on October 17, 2005 that previously reported financial results should be restated to reflect the correction of the errors. The Audit Committee agreed with this recommendation. Pursuant to the recommendation of the Audit Committee, the Board of Directors determined at its meeting on October 17, 2005 that the previously reported results for Petroleum Development Corporation be restated to correct the errors in the accounting for derivatives and in the Company's oil and gas property accounting. In light of the restatement the Board of Directors also determined that the financial statements and other information containing the errors should no longer be relied upon.

Based on the information to date, these accounting issues did not influence incentive or other compensation in the past. Going forward the adjustments in the restated financials will not be used to influence positively any person's compensation.

Restatement

In response to the issues raised by the review of the Company's accounting policies and procedures described above:

1. We have completed a review of the documentation and accounting for derivative transactions used by the Company for its commodity based derivative transactions and interest rate swap.

2. We will account for existing and future derivative transactions as non-hedges unless they meet all of the requirements for treatment as cash flow hedges including the appropriate documentation.

3. We have revised our division of properties into fields to correspond with the definition of "fields" according to FAS 19.

4. We have revised our policies and procedures for calculating depreciation, depletion and amortization to correct the errors previously identified.

5. We have revised our policies and procedures for calculating asset retirement obligations to correct errors previously identified.

6. We have revised our policies and procedures for calculating our income tax provision to correct errors previously identified.

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7. We have implemented extensive employee training and purchased additional financial and tax reporting software programs.

8. We have obtained the services of a derivatives expert and are in the process of obtaining an oil and gas accounting and income tax specialist for consulting and review services.

We have restated the previously issued financial statements to reverse the effects of the incorrect use of hedge accounting, the errors in oil and gas property accounting, the error in calculating the asset retirement obligations, and the error in income taxes.

Effects of the Restatement

The following tables set forth the effects of the restatement with respect to the quarters ended March 31, 2005 and 2004.

Effects on Statements of Income

Income (expense)(in thousands; per-share amounts in dollars)	Quarter Ended March 31, (Unaudited) 2005	(Unaudited) 2004
Depreciation, depletion, and amortization	$ (32)	$ (36)
Asset retirement obligations	$ (104)	$ (97)
Disqualification of hedge accounting	(4,147)	(1,013)
Provision for income taxes	1,585	413
Net decrease in reported net income	$ (2,698)	$ (733)
Basic, as reported	$ 0.80	$ 0.53
Adjustment	(0.16)	(0.04)
Basis, as restated	$ 0.64	$ 0.49
Diluted, as reported	$ 0.80	$ 0.52
Adjustment	(0.16)	(0.05)
Diluted, as restated	$ 0.64	$ 0.47

As set forth in Item 4 of this Form 10-Q/A and more fully described in item 9A of the Annual Report on Form 10-K/A filed by the Company with respect to the year ended December 31, 2004, the Company has determined that its disclosure controls and procedures were not effective as of March 31, 2005.

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 March 31, 2005, and the related condensed consolidated statements of income and cash flows for the three-month periods ended March 31, 2005 and 2004. These condensed consolidated financial statements are the responsibility of the Company's management.

We conducted our reviews 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 reviews, 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 13, 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 note 10 to the condensed consolidated financial statements the Company has restated the condensed consolidated balance sheets as of March 31, 2005 and December 31, 2004, and the condensed consolidated statements of income and cash flows for the three month periods ended March 31, 2005 and 2004.

KPMG LLP

Pittsburgh, Pennsylvania

May 5, 2005, except as to note 10, which is as of December 16, 2005

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Balance Sheets

March 31, 2005 and December 31, 2004

ASSETS

	2005 (Unaudited) (Restated)	2004 (Restated)
Current assets:		
Cash and cash equivalents	$ 94,629,100	$ 77,735,300
Accounts and notes receivable	36,247,100	36,065,300
Inventories	3,837,600	1,657,300
Prepaid expenses	8,819,100	9,878,900
Total current assets	143,532,900	125,336,800
Properties and equipment	319,677,500	299,748,700
Less accumulated depreciation, depletion and amortization	97,000,200	92,165,400
	222,677,300	207,583,300
Other assets	2,667,700	2,108,200
	$ 368,877,900	$ 335,028,300

(Continued)

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Balance Sheets, Continued

March 31, 2005 and December 31, 2004

LIABILITIES AND STOCKHOLDERS' EQUITY

	2005 (Unaudited) (Restated)	2004 (Restated)
Current liabilities:		
Accounts payable and accrued expenses	$ 78,527,500	$ 69,696,600
Advances for future drilling contracts	54,421,100	42,497,300
Funds held for future distribution	15,404,400	12,911,800
Total current liabilities	148,353,000	125,105,700
Long-term debt	18,000,000	21,000,000
Other liabilities	5,086,400	3,927,500
Deferred income taxes	24,500,700	22,976,300
Asset retirement obligations	8,160,100	7,998,200
Stockholders' equity:		
Common stock par value $0.01 per share; authorized 50,000,000 shares; issued and outstanding 16,589,824 shares and 16,589,824 shares	165,800	165,800
Additional paid-in capital	37,684,300	37,684,300
Retained earnings	127,692,400	117,052,500
Unamortized stock award	(764,800)	(882,000)
Total stockholders' equity	164,777,700	154,020,600
	$ 368,877,900	$ 335,028,300

See accompanying notes to unaudited condensed consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Statements of Income

Three Months ended March 31, 2005 and 2004

(Unaudited)

	2005 (Restated)	2004 (Restated)

Revenues:		
Oil and gas well drilling operations	$ 32,351,200	$ 29,499,300
Gas sales from marketing activities	17,522,000	22,058,900
Oil and gas sales	18,663,700	16,316,200
Well operations and pipeline income	2,112,400	1,837,500
Other income	6,213,800	58,100
Total revenues	76,863,100	69,770,000
Costs and expenses:		
Cost of oil and gas well drilling operations	27,629,000	25,355,700
Cost of gas marketing activities	17,901,600	21,889,700
Oil and gas production and well operations cost	4,163,400	3,906,100
General and administrative expenses	1,617,500	994,200
Depreciation, depletion, and amortization	4,856,900	4,544,400
Total costs and expenses	56,168,400	56,690,100
Income from operations	20,694,700	13,079,900
Interest expense	147,800	209,600
Oil and gas price risk management loss, net	3,659,100	830,000
Income before income taxes	16,887,800	12,040,300
Income taxes	6,247,900	4,334,400
Net income	$ 10,639,900	$ 7,705,900
Basic earnings per common share	$ 0.64	$ 0.49
Diluted earnings per common share	$ 0.64	$ 0.47

See accompanying notes to unaudited condensed consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows

Three Months Ended March 31, 2005 and 2004

(Unaudited)

	2005 (Restated) (a)	2004 (Restated) (a)

Cash flows from operating activities:		
Net income	$10,639,900	$ 7,705,900
Adjustments to net income to reconcile to cash provided by (used in) operating activities:		
Deferred federal income taxes	1,524,400	2,373,800
Depreciation, depletion & amortization	4,856,900	4,544,400
Accretion of asset retirement obligation	115,000	105,700
(Gain)/loss from sale of assets	(5,163,100)	3,000
Leasehold acreage expired or surrendered	9,100	51,000
Amortization of stock award	117,200	900
Unrealized loss on derivative transactions	4,147,500	1,012,900
Decrease (increase) in current assets	4,966,400	(20,600)
Decrease in other assets	13,000	18,800
Increase (decrease) in current liabilities	13,273,700	(28,915,700)
(Decrease) increase in other liabilities	(870,400)	168,900
Total adjustments	22,989,700	(20,656,900)
Net cash provided by (used in) operating activities	33,629,600	(12,951,000)
Cash flows from investing activities:		
Capital expenditures	(20,099,500)	(1,825,800)
Proceeds from sale of leases to partnerships	195,500	624,100
Proceeds from sale of assets	6,168,200	22,400
Net cash used in investing activities	(13,735,800)	(1,179,300)
Cash flows from financing activities:		
Net retirement of long-term debt	(3,000,000)	(11,000,000)
Proceeds from stock option exercises	-	1,685,700
Repurchase and cancellation of treasury stock	-	(1,294,600)
Net cash used in financing activities	(3,000,000)	(10,608,900)
Net increase (decrease) in cash and cash equivalents	16,893,800	(24,739,200)
Cash and cash equivalents, beginning of period	77,735,300	80,379,300
Cash and cash equivalents, end of period	$94,629,100	$ 55,640,100

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 (used in) operating activities is the same as the original Form 10-Q filing.

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PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Notes to Condensed Consolidated Financial Statements

March 31, 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. This amendment to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 (the "Form 10-Q") of Petroleum Development Corporation (the "Company") is being filed in order to restate the condensed consolidated financial statements as of March 31, 2005 and 2004 and for the quarters ended March 31, 2005 and 2004 and to make corresponding changes to Item 2, Management's Discussion and Analysis of Financial Condition and Results of Operations, and Item 4, Controls and Procedures. The Company has previously filed an amended annual report on Form 10-K/A for 2004 to restate prior periods. Certain of those restated prior periods are reflected in this Form 10-Q/A and noted as restated. See restatement Note 10 on Page 13 of this filing.

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 in 2005 would have been $23,800. There would have been no impact on reported net income in 2004.

Three Months Ended

	March 31	
	2005 (Restated)	2004 (Restated)
Net income, as reported	$ 10,639,900	$ 7,705,900
Stock-based employee compensation expense included in reported net income, net of related tax effects	73,800	600
Deduct total stock-based employee compensation expense determined under fair-value-based method for all awards, net of tax	(97,600)	(600)
Pro forma net income	$ 10,616,100	$ 7,705,900
Basic earnings per share as reported	$ 0.64	$ 0.49
Pro forma basic earnings per share	$ 0.64	$ 0.49
Diluted earnings per share as reported	$ 0.64	$ 0.47
Pro forma diluted earnings per share	$ 0.63	$ 0.47

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 to a fair statement of the results of such periods have been made. The results of operations for the three months ended March 31, 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 is as follows for the three months ended March 31, 2005 and 2004:

	2005 (Restated)	2004 (Restated)
Weighted average common shares outstanding	16,589,824	15,861,897
Weighted average common and common equivalent shares outstanding	16,642,888	16,304,526
Net income	$ 10,639,900	$ 7,705,900
Basic earnings per share	$ 0.64	$ 0.49
Diluted earnings per share	$ 0.64	$ 0.47

6. Business Segments

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 approximately 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 months ended March 31, 2005 and 2004 as restated is as follows: (All amounts presented below are in thousands.)

	2005 (Restated)	2004 (Restated)
REVENUES		
Drilling and Development	$ 32,351	$ 29,499
Natural Gas Marketing	17,582	22,068
Oil and Gas Sales	18,664	16,316
Well Operations and Pipeline Income	2,113	1,838
Unallocated amounts (1)	6,153	49
Total	$ 76,863	$ 69,770

	2005 (Restated)	2004 (Restated)

SEGMENT INCOME (LOSS) BEFORE INCOME TAXES			
Drilling and Development	$	4,722	$ 4,143
Natural Gas Marketing		(321)	176
Oil and Gas Sales		7,019	8,055
Well Operations and Pipeline Income		1,230	920
Unallocated amounts (2)			
General and Administrative expenses		(1,618)	(994)
Interest expense		(148)	(210)
Other (1)		6,004	(50)
Total	$	16,888	$ 12,040
		March 31, 2005 (Restated)	December 31, 2004 (Restated)
SEGMENT ASSETS			
Drilling and Development	$	65,239	$ 64,348
Natural Gas Marketing		29,482	31,234
Oil & Gas Sales		246,339	211,255
Well Operations and Pipeline Income		18,996	16,518
Unallocated amounts			
Cash		33	112
Other		8,789	11,561
Total	$	368,878	$ 335,028

(1) Includes interest on investments and partnership management fees, and during the three months ended

March 31, 2005 includes a lease sale with a gain of $5.2 million, which are not allocated in assessing segment performance.

(2) Items which are not allocated in assessing segment performance.

7. Sale of Undeveloped Acreage

On January 28, 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 is required to remit $1.0 million to the original lessor, unless it constructs certain facilities adjacent to this undeveloped property subject to certain timing conditions. The Company at this time cannot determine if it will be able to comply with this provision, therefore a $1.0 million accrual has been established and the pre-tax gain on the sale was reduced to $5.2 million. This gain has been included in "Other Income" in the accompanying income statement and amounted to an after-tax effect on Earnings Per Share of $.20.

8. 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 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 quarter 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), 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 $7.5 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 three months ended March 31, 2005 and 2004, the Company paid partnerships a total of $124,200 and $97,200 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 March 31, 2005, the Company has an outstanding commitment for $672,750.

The Company drilled one exploratory well in 2004 (Fox Federal #1-13) and drilled another in the first quarter of 2005 (Coffeepot Springs #24-34). The Fox Federal #1-13 has been completed and testing was underway, however, the well has not been classified as successful or dry. Testing of this well was suspended in January due to lease restrictions on the Federal lease. We expect to resume testing late in the second quarter of 2005. The cost of this well as of April 30, 2005 is $4.5 million. The Coffeepot Springs #24-34 has been drilled to total depth and is scheduled to be fractured in the next few weeks and has not been classified as successful or dry. The cost of this well as of April 30, 2005 is $2.6 million. If either of these wells is determined to be a dry hole, its cost will be expensed in the period when the determination is made as required by the successful efforts method of accounting.

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.

9. Subsequent Event

On April 27, 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 will record a gain of approximately $1.5 million in the second quarter of 2005. The transaction was effective April 1, 2005.

10. 2005 Restatement

During the course of our preparation of Company's second quarter financial statements for 2005, we identified errors with respect to the Company's use of hedge accounting for certain transactions under Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended (FAS 133). We identified errors in our interpretation of Statements of Financial Accounting Standards No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies (FAS 19) in regards to the Company's calculation of depreciation and potential impairment of its oil and gas properties. We discovered an error in our adoption of

Statement of Financial Accounting Standards No. 143, Asset Retirement Obligations (FAS 143) for the Company's oil and gas well retirement obligations. We also identified errors in the calculation of our provision for income taxes. A description of these errors follows:

- The Company revised its accounting for its derivative transactions, primarily due to the reasons set forth below. The Company used hedge accounting for derivative positions that did not qualify for hedge accounting. These errors began in the first quarter of 2001, the effective date of FAS 133, and continued through the first quarter of 2005.

    a. The Company did not have sufficient documentation required for these derivatives to qualify for hedge accounting treatment and did not test them periodically for effectiveness as required by FAS 133.
    b. The Company did not record the fair value of certain natural gas purchases and sales contracts which were deemed to be derivatives on its consolidated balance sheet, and changes in fair value were not recorded in earnings.
    c. The Company reported the fair value of derivative transactions entered into on behalf of its affiliated partnerships on the balance sheet net of the amount due to/from the partnerships. The fair value of these derivative transactions should have been reported at gross.

- The Company revised its accounting for oil and gas properties primarily due to the following reasons.

a. The Company's division of its oil and gas properties into fields for calculation of depreciation and depletion and for the determination of impairments was not consistent with applicable rules in FAS 19. According to FAS 19, a field is defined to be "an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition". In accounting for its oil and gas properties, the Company included areas that should have been treated as separate fields as part of a single field. The financial impacts of corrections to divide the Company's oil and gas properties into revised fields were included in the restated financial statements.

b. It was determined that certain policies and procedures the Company followed for calculating quarterly depreciation were incorrect. The Company utilized the previous annual oil and gas reserve reports to estimate quarterly depreciation and adjusted the yearly depreciation based upon the new oil and gas reserve report at the end of the next year. However, each interim period's depreciation must stand on its own and should not be adjusted at the year end upon the issuance of a new oil and gas reserve report. The financial impacts of corrections to calculate each interim period's depreciation on its own were included in the restated financial statements.

c. The Company also used its proved developed reserves, as defined by Securities and Exchange Commission rules, to calculate depreciation. The Company's proved developed reserves included the anticipated recompletion of the Codell formation in Wattenberg Field in Colorado as well as behind pipe zones in the Appalachian Basin. After reviewing the rules, the Company concluded that both the future estimated costs and the reserves from these "behind pipe reserves" should be excluded in calculating the depreciation amounts. This change resulted in increases in depreciation compared to the method previously used by the Company until the recompletions and behind pipe reserves are completed. The financial impacts of corrections to exclude both the future estimated costs and the reserves from these "behind pipe reserves" in calculating depreciation amounts were included in the restated financial statements.

- The Company revised its accounting for its asset retirement obligations due to the following reason.

a. The Company interpreted FAS No. 143 as requiring the recording of a liability based on the probable occurrence of certain conditional future events. The Company incorrectly based its estimates of future disposal costs of wells on its historical record of disposing of its wells in ways that transferred asset retirement costs to other parties. The Company has concluded that a liability should be recognized when a legal obligation exists, regardless of conditional future events, and that the full fair value of potential future disposal costs should have been recorded despite the Company's historical practice of transferring most of the obligation to other parties. This error began in the first quarter of 2003, the effective date of FAS No.143, and continued through the first quarter of 2005 and is being corrected through this restatement.

- The Company revised its accounting for its provision for income taxes in its financial statements due to the following reason.

a. The Company incorrectly determined the portion of the percentage depletion of oil and gas properties for tax purposes which was treated as a permanent difference in the calculation of its tax provision, and incorrectly determined the classification of certain accrued and deferred income tax balances.

Effects of the Restatement

This restatement also impacted or made changes to the following condensed consolidated financial statement footnotes, Note 2, 5, 6, and added Note 10, 2005 Restatement.

The following tables set forth the effects of the restatement relating to the derivatives transactions, oil and gas property accounting, asset retirement obligations and provision for income taxes on the affected line items within the Company's previously reported unaudited Condensed Consolidated Statements of Income for the quarters ended March 31, 2005 and 2004.

Summary of Effects on Statement of Income

	Quarter Ended March 31,	
	2005	2004
Income (expense)(in thousands);		
Depreciation, depletion, and amortization	$ (32)	$ (36)
Asset retirement obligations	(104)	(97)
Disqualification of the use of hedge accounting(1)	(4,147)	(1,013)
Provision for income taxes	1,585	413
Net decrease in reported net income	$ (2,698)	$ (733)

(1) The errors in accounting for the Company's derivatives effected the income statement line items as outlined below:

	Quarter Ended March 31,	
	2005	2004
Gas sales from marketing activities	$ (6,779)	$ (1,399)
Oil and gas sales	201	120
Cost of gas marketing activities	6,090	965
Interest expense	-	131
Oil and gas price risk management loss, net	(3,659)	(830)
Net decrease in reported net income	$ (4,147)	$ (1,013)

The effect of the restatement on the quarterly financial statements by line item follows;

	March 31, 2005		December 31, 2004	
	(in thousands)			
	As previously reported	As restated	As previously reported	As restated
Condensed Consolidated Balance Sheet Data:				
Accounts and notes receivable	$ 29,932	$ 36,247	$ 33,903	$ 36,065
Prepaid assets	3,861	8,819	7,334	9,879
Total current assets	132,260	143,533	120,630	125,337
Total properties and equipment	328,230	319,678	308,348	299,749
Accumulated depreciation, depletion and amoritization	93,144	97,000	88,341	92,165
Net properties and equipment	235,086	222,677	220,007	207,583
Other assets	729	2,668	757	2,108
Total assets	368,075	368,878	341,393	335,028
Accounts payable and accrued expenses	70,355	78,528	65,757	69,697
Total current liabilities	140,181	148,353	121,166	125,106
Other liabilities	5,072	5,086	3,927	3,928
Deferred income taxes	30,209	24,501	29,843	22,976
Asset retirement obligations	795	8,160	784	7,998
Retained earnings	143,448	127,692	130,110	117,053
Accumulated other comprehensive loss, net of tax	(6,715)	-	(2,405)	-
Total stockholders' equity	173,818	164,778	164,673	154,021
Total liabilities and stockholders' equity	368,075	368,878	341,393	335,028
For the three months ended March 31,	2005		2004	
(in thousands, per share amounts in dollars)	As previously reported	As restated	As previously reported	As restated
Condensed Consolidated Statement of Income Data:				
Gas sales from marketing activities	$ 24,301	$ 17,522	$ 23,457	$ 22,059
Oil and gas sales	18,463	18,664	16,196	16,316
Total revenues	83,442	76,863	71,049	69,770
Cost of gas marketing activities	23,992	17,902	22,855	21,890
Depreciation, depletion and amortization	4,825	4,857	4,508	4,544
Income from operations	-	20,695	-	13,080
Interest expense	44	148	244	210
Oil and gas price risk management loss, net	-	3,659	-	830
Income before income taxes	21,171	16,888	13,187	12,040
Income taxes	7,833	6,248	4,747	4,334
Net income	1,338	10,640	8,439	7,706
Per share amounts (in dollars)				
Basic earnings per share	$ 0.80	$ 0.64	$ 0.53	$ 0.49
Diluted earnings per share	$ 0.80	$ 0.64	$ 0.52	$ 0.47

Consolidated Statement of Cash Flows:

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

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

2005 Restatement

As previously mentioned under "Explanatory Note - 2005 Restatement" on Page 1 and Note 10 on Page 13 of this Form 10-Q/A, the Company's Quarterly Report on Form 10-Q for the three months ended March 31, 2005 and 2004 is being amended to correct errors in the Company's accounting for derivative transactions, certain aspects of the Company's oil and gas property accounting including methods used to calculate depreciation for oil and gas properties, incorrect adoption of FAS 143 accounting for asset retirement obligations and income taxes. The restatement had no effect on our cash flows.

Results of Operations

The Company has recorded historically strong revenues, income and cash flow for the first quarter 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 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.

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

Three Months Ended March 31, 2005 Compared with March 31, 2004

Revenues

Total restated revenues for the three months ended March 31, 2005 were $76.9 million compared to a restated $69.8 million for the three months ended March 31, 2004, an increase of approximately $7.1 million or 10.2 percent. Such increase was primarily the result of the $5.2 million gain on the sale of undeveloped acreage.

Drilling Revenues

Drilling revenues for the three months ended March 31, 2005 were $32.4 million compared to $29.5 million for the three months ended March 31, 2004, an increase of approximately $2.9 million or 9.8 percent. Such increase was due to the increased drilling funds raised through the Company's Public Drilling Programs. The Company started the first quarter of 2005 with advances for future drilling from December 31, 2004 of $42.5 million. The Company funded its first drilling partnership of the year in the first quarter with $40 million in subscriptions and commenced drilling of the partnership wells late in the first quarter. 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

Restated natural gas sales from the marketing activities of Riley Natural Gas (RNG), the Company's gas marketing subsidiary for the three months ended March 31, 2005 were $17.5 million compared to $22.1 million for the three months ended March 31, 2004, a decrease of approximately $4.6 million or 20.8 percent. Such decrease was due to unrealized losses on derivative transactions which amounted to $6.8 million and $1.4 million for the three months ended March 31, 2005 and 2004, respectively.

Oil and Gas Sales

Restated oil and gas sales from the Company's producing properties for the three months ended March 31, 2005 were $18.7 million compared to a restated $16.3 million for the three months ended March 31, 2004, an increase of $2.4 million or 14.7 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 March 31, 2005 was 2.7 million Mcf at an average restated sales price of $5.27 per Mcf compared to 2.6 million Mcf at an average restated sales price of $4.94 per Mcf for the three months ended March 31, 2004. Oil sales were 100,900 barrels at an average restated sales price of $44.19 per barrel for the three months ended March 31, 2005 compared to 104,000 barrels at an average restated sales price of $32.32 per barrel for the three months ended March 31, 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 March 31, 2005			Three Months Ended March 31, 2004		
	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)*	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)*
Appalachian Basin	1,099	451,052	457,646	1,204	457,218	464,442
Michigan Basin	982	412,548	418,440	1,151	443,962	450,868
Rocky Mountains	98,815	1,832,635	2,425,525	101,781	1,721,812	2,332,498
Total	100,896	2,696,235	3,301,611	104,136	2,622,992	3,247,808
Average Price (restated)	$44.19	$5.27	$5.65	$32.32	$4.94	$5.02

*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 October of 2006 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 March 31, 2005 the Company averaged natural gas volumes sold of 899,000 Mcf per month and oil sales of 33,600 barrels per month. The positions in effect on May 6, 2005 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 Derivatives - (Appalachian and Michigan Basin)					
2/04	Apr 2005 - Oct 2005	122,000	$4.28	61,000	$5.00
3/05	Apr 2005 - Oct 2005	39,000	$5.75	19,500	$8.37
1/05	Nov 2005 - Mar 2006	156,000	$5.00	78,000	$8.50
3/05	Apr 2006 - Oct 2006	78,000	$5.50	39,000	$7.40
Colorado Interstate Gas (CIG) Based Derivatives (Piceance Basin)					
2/04	Apr 2005 - Oct 2005	33,000	$3.10	16,000	$4.43
3/05	Apr 2005 - Oct 2005	38,000	$4.75	19,000	$8.12
1/05	Nov 2005 - Mar 2006	60,000	$4.50	30,000	$7.15
3/05	Apr 2006 - Oct 2006	42,000	$4.50	21,000	$7.25
NYMEX Based Derivatives (NECO Area)					
2/04	Apr 2005 - Oct 2005	150,000	$4.26	75,000	$5.00
1/05	Nov 2005 - Mar 2006	150,000	$5.00	75,000	$8.45
4/05	Apr 2006 - Oct 2006	150,000	$5.00	75,000	$8.62
Oil - NYMEX Based (Wattenberg Field)					
		Bbls		Bbls	
8/04	Apr 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 March 31, 2005 were $2.1 million compared to $1.8 million for the three months ended March 31, 2004, an increase of approximately $300,000 or 16.7 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 March 31, 2005 was $6.2 million compared to $58,000 for the three months ended March 31, 2004, an increase of $6.1 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 January 2005 for a pre-tax profit of $5.2 million, along with management fees collected from the funding of our 2005-A drilling partnership and interest earned on higher average cash balances.

Costs and Expenses

Restated costs and expenses for the three months ended March 31, 2005 were $56.2 million compared to a restated $56.7 million for the three months ended March 31, 2004, a decrease of approximately $500,000 or 0.9 percent.

Oil and Gas Well Drilling Operations Costs

Oil and gas well drilling operations costs for the three months ended March 31, 2005 were $27.6 million compared to $25.4 million for the three months ended March 31, 2004, an increase of approximately $2.2 million or 8.7 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 March 31, 2005 was 14.6% compared with 14.0% for the three months ended March 31, 2004, an increase in gross margin of 0.6%. For the first two partnerships in 2005, the Company has raised its footage-based drilling rates it charges to its Public Drilling Partnerships to correspond with the rising well fracturing and steel costs for casing and other well equipment.

Cost of Gas Marketing Activities

The restated costs of gas marketing activities for the three months ended March 31, 2005 were $17.9 million compared to a restated $21.9 million for the three months ended March 31, 2004, a decrease of $4.0 million or 18.3 percent. Such decrease was due primarily to an increase in the unrealized gain on derivatives from $965,000 at March 31, 2004 compared to $6.1 million at March 31, 2005. Income before income taxes for the Company's natural gas marketing subsidiary decreased from an income of $176,000 for the three months ended March 31, 2004 to a loss of $321,000 for the three months ended March 31, 2005, as a result of the unrealized derivative loss, discussed previously under "Natural Gas Marketing Activities".

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 March 31, 2005 were $4.2 million compared to $3.9 million for the three months ended March 31, 2004, an increase of approximately $300,000 or 7.7 percent. Such increase was due to increased production costs and severance and property taxes on the increased volumes and 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 $.98 to $1.09 per Mcfe 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.

General and Administrative Expenses

General and administrative expenses for the three months ended March 31, 2005 were $1,617,000, compared to $994,000 for the three months March 31, 2004, an increase of approximately $623,000, or 62.7 percent. The increase was due to the costs of complying with the various provisions of Sarbanes Oxley, in particular with Section 404 (Internal Controls), which amounted to $550, 000 for the three months ended March 31, 2005.

Depreciation, Depletion, and Amortization

Restated depreciation, depletion, and amortization costs for the three months ended March 31, 2005 increased to $4.9 million from approximately a restated $4.5 million for the three months ended March 31, 2004, an increase of approximately $400,000 or 8.9 percent. Such increase was due to the increased production and investment in oil and gas properties by the Company.

Interest Expense

Restated interest expense for the three months ended March 31, 2005 was $148,000 compared to $210,000 for the three months ended March 31, 2004, a decrease of $62,000 or 29.5 percent. Such decrease was due to significantly lower average outstanding balances of our credit facility offset in part by higher interest rates and increased accretion related to Asset Retirement Obligations. 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 March 31, 2005 was $867,000 compared to $12.1 million for the three months ended March 31, 2004.

Oil and Gas Price Risk Management Loss, Net

For the three months ended March 31, 2005, the Company had restated unrealized losses of $3,458,600 and realized losses of $200,500 compared to the three months ended March 31, 2004 balance which was comprised of unrealized losses of $710,000 and realized losses of $120,000. The 2005 change is the result of increasing natural gas prices. Oil and gas price risk management loss, net is comprised of both the realized and unrealized portions of the Company's commodity based derivative transactions for its oil and gas production (this line item does not include commodity based derivative transactions related to transactions from marketing activities). The Company views these transactions as financial tools used for risk management and cash flow planning.

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes increased from approximately 36 percent to 37 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

Restated net income for the three months ended March 31, 2005 was $10.6 million compared to a restated net income of $7.7 million for the three months ended March 31, 2004, an increase of approximately $2.9 million or 37.7 percent.

Restated diluted earnings per share for the three months ended March 31, 2005 was $0.64 per share compared to a restated $0.47 per share for the three months ended March 31, 2004, an increase of $0.17 per share or 36.2 percent.

Liquidity and Capital Resources

The 2005 restatement, addressed earlier, has no impact on the Company's liquidity and capital resources. The Company funds its operations through a combination of cash flow from operations including profits from drilling partnerships and use of the Company's credit facility.

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 for 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 prices. Through October of 2006 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. See previous pages in this Management's Discussion and Analysis for a schedule of derivative instruments.

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 quarter 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 quarter. 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 to date. 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 quarter of 2005.

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

The third and final partnership of 2005 is scheduled to close later in the year with maximum subscriptions of $35 million. If the Company sells $35 million in the third 2005 partnership, the total subscriptions in 2005 will be $115 million compared to $100 million for 2004. 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 this level of funding from these or future programs.

Substantially all of the Company's drilling programs contain a repurchase provision allowing Investors to request that the Company repurchase their partnership units at any time beginning with the third anniversary after 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 and subject to the Company's financial ability to do so. The maximum annual 10% repurchase obligation, if requested by the investors, is currently approximately $7.5 million. The Company has adequate liquidity to meet this obligation. During the first three months of 2005, the Company spent $59,300 under this provision.

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".

Drilling Activity

During the first three months 2005, the Company drilled along with its public drilling fund partnerships a total of 38 successful wells. The Company drilled 29 successful wells in its Wattenberg field in the Denver-Julesburg Basin and nine 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.

In the first quarter of 2005, the Company also drilled for its own account a four-well program on 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 in 2003.

The Company drilled one exploratory well in 2004 (Fox Federal #1-13) and drilled another one in the first quarter of 2005 (Coffeepot Springs #24-34). The Fox Federal #1-13 has been completed and testing was underway but the well has not been classified as successful or dry. Testing of this well was suspended in January due to lease restrictions on the Federal lease. We expect to resume testing late in the second quarter of 2005. The cost of this well as of April 30, 2005 is $4.5 million. The Coffeepot Springs #24-34 has been drilled to total depth and is scheduled to be fractured in the next few weeks and has not been classified as successful or dry. The cost of this well as of April 30, 2005 is $2.6 million. If either of these wells is determined to be a dry hole, its cost will be expensed in the period when the determination is made as required by the successful efforts method of accounting. Currently the Company plans to retain most if not all of the working interest in the exploratory wells, since the Company partnerships focus on developmental activities and are allowed only limited participation in exploratory drilling.

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 three 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 three months ended March 31, 2005 are presented below:

Property acquisition cost:	
Proved undeveloped properties	$ 3,776,700
Producing properties	72,600
Development costs	13,098,400
Exploration costs	2,575,400
	$ 19,523,100

Common Stock Repurchase Program

At a meeting held on Friday, March 18, 2005, the Board of Directors of Petroleum Development Corporation approved a stock repurchase plan to allow the Company to repurchase up to 2% of the Company's common stock in 2005. The Company intends at a minimum to purchase adequate shares to insure no dilution from employee stock compensation plans and may also make open market purchases from time to time.

Working Capital

Although the Working Capital of the Company as of March 31, 2005 is a negative $4.8 million this amount included a liability of $14.2 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 upon settlement, and will not require additional expenditures of cash upon settlement since it will be funded with proceeds from the sale of future production.

Long-Term Debt

The Company has a credit facility with Chase Bank NA and BNP Paribas of $100 million subject to and secured by adequate levels of oil and gas reserves. The current total borrowing base is $80.0 million of which the Company has activated $60 million of the facility. The Company is required to pay a commitment fee of 1/4 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. No principal payments are required until the credit agreement expires on July 3, 2008.

As of March 31, 2005, the outstanding balance was $18,000,000. 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, maintenance of certain working capital and tangible net worth ratios along with a restriction on the payment of dividends. As of March 31, 2005, the Company was in compliance with all financial covenants in the credit agreement. As of the filing of this Form 10-Q/A the Company was in compliance with all financial covenants in the credit agreement except for timely filing of the June 30, 2005 and September 30, 2005 Form 10-Q's. The Company has received bank waivers to extend the filing of the June 30, 2005 Form 10-Q and the September 30, 2005 Form 10-Q until December 31, 2005.

Contractual Obligations

Contractual obligations as of March 31, 2005 and due dates are as follows:

Contractual Obligations	Total	Less than 1 year	1-3 Years	3-5 Years	More than 5 years
Long-Term Debt	$ 18,000,000	$ -	$ -	$ 18,000,000	$ -
Operating Leases	816,700	299,700	331,200	139,800	46,000
Asset Retirement Obligations	8,160,000	50,000	100,000	100,000	7,910,000
Drilling Rig Commitment	672,800	672,800	-	-	-
Derivative Agreements	15,770,000	14,228,800	1,541,200	-	-
Other Liabilities	3,097,100	40,000	250,000	250,000	2,557,100
Total	$ 46,516,600	$ 15,291,300	$ 2,222,400	$ 18,489,800	$ 10,513,100

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 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 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 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 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 in addition to the increased drilling costs, 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 derivatives were in place. The Company uses derivatives to reduce the impact of price movements on revenue. While these derivatives 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 2,700 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 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 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 and hedging activities 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 Consolidated Balance Sheets at fair value. Changes in fair value of derivatives are recorded in earnings in the restated consolidated statements of income as none of the Company's derivatives qualified for hedge accounting under the provisions of FAS No. 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 producing 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 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 guidance in the FSP is required to be applied to the first reporting period beginning after April 4, 2005 on a prospective basis to existing and newly capitalized exploratory well costs. The Company does not expect the application of this FSP to have a significant impact on the Company's financial position or results of operations.

Disclosure Regarding Forward Looking Statements

Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995

Statements, other than historical facts, contained in this Quarterly Report on Form 10-Q/A, including statements of estimated oil and gas production and reserves, drilling plans, future cash flows, anticipated capital expenditures and Management's strategies, plans and objectives, are "forward looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Although the Company's management believes that its forward looking statements are based on reasonable assumptions, it cautions that such statements are subject to a wide range of risks and uncertainties incidental to the exploration for, acquisition, development and marketing of oil and gas, and it can give no assurance that its estimates and expectations will be realized. Important factors that could cause actual results to differ materially from the forward looking statements include, but are not limited to, changes in production volumes, worldwide demand, and commodity prices for petroleum natural resources; the timing and extent of the Company's success in discovering, acquiring, developing and producing oil and gas reserves; the Company's ability to acquire leases and drilling rigs at reasonable prices; the Company's ability to raise funds through its Partnership Drilling Programs; risks incident to the drilling and operation of oil and gas wells; future production and development costs; the effect of existing and future laws, governmental regulations and the political and economic climate of the United States; the effect of derivative activities; and conditions in the capital markets. Other risk factors are discussed elsewhere in this Form 10-Q/A.

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/A.

Item 3. <u>Quantitative and Qualitative Disclosure About Market Rate Risk</u>

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, CIG-based contracts traded by JP Morgan for Colorado production and purchase and sales contracts with customers deemed to be derivatives. 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 sales contracts for Riley Natural Gas and PDC as of March 31, 2005 and 2004.

Riley Natural Gas
Restated Open Derivative Contracts

Commodity	Type	Quantity Gas-Mmbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Value
Total Contracts as of March 31, 2005					
Natural Gas	Cash Settled Sale	3,947,000	$ 6.10	$ 24,072,530	$ (6,875,781)
Natural Gas	Cash Settled Purchase	710,000	$ 6.48	$ 4,602,990	$ 1,007,870
Natural Gas	Cash Settled Sale Option	320,000	$ 5.42		$ 6,492
Natural Gas	Cash Settled Purchase Option	160,000	$ 7.06		$ (150,218)
Natural Gas	Physical Contract Sale	553,211	$ 7.82	$ 4,325,544	$ (489,742)
Natural Gas	Physical Contract Purchase	3,928,100	$ 6.40	$ 25,149,432	$ 6,543,287
			12		
Natural Gas	Cash Settled Sale	2,947,000	$ 6.36	$ 18,734,450	$ (4,889,375)
Natural Gas	Cash Settled Purchase	610,000	$ 6.62	$ 4,037,140	$ 846,990
Natural Gas	Cash Settled Sale Option	320,000	$ 5.42		$ 6,492
Natural Gas	Cash Settled Purchase Option	160,000	$ 7.06		$ (150,218)
Natural Gas	Physical Contract Sale	446,531	$ 7.83	$ 3,497,873	$ (475,039)
Natural Gas	Physical Contract Purchase	2,928,100	$ 6.63	$ 19,420,636	$ 4,712,624

Prior Year Total Contracts as of March 31, 2004					
Natural Gas	Cash Settled Sale	3,380,000	$ 4.77	$ 16,115,800	$ (3,286,000)
Natural Gas	Cash Settled Purchase	580,000	$ 4.90	$ 2,402,300	$ 397,400
Natural Gas	Cash Settled Sale Option	360,000	$ 4.75		$ 35,682
Natural Gas	Cash Settled Purchase Option	180,000	$ 6.74		$ (66,246)
Natural Gas	Physical Contract Sale	413,005	$ 6.25	$ 2,583,230	$ (87,842)
Natural Gas	Physical Contract Purchase	3,391,700	$ 5.09	$ 17,274,524	$ 2,861,496

The maximum term over which RNG is managing exposure to the variability of cash flows for commodity price risk is 27 months.

Petroleum Development Corporation
Restated Open Derivative Contracts

Commodity	Type	Quantity Gas-Mmbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Value
Total Contracts as of March 31, 2005					
Natural Gas	Purchase	35,100	$ 6.58	$ 230,802	$ 46,554
Natural Gas	Sale Option	6,328,416	$ 4.72		$ 259,811
Natural Gas	Purchase Option	3,164,208	$ 7.08		$ (4,305,774)
Crude Oil	Sale Option	118,341	$ 32.30		3,818
Crude Oil	Purchase Option	59,171	$ 40.00		(981,930)
Contracts maturing in 12 months following March 31, 2005					
Natural Gas	Purchase	35,100	$ 6.58	$ 230,802	$ 46,554
Natural Gas	Sale Option	4,996,176	$ 4.68		$ 141,062
Natural Gas	Purchase Option	2,498,088	$ 6.74		$ (4,116,699)
Crude Oil	Sale Option	118,341	$ 32.30		$ 3,818
Crude Oil	Purchase Option	59,171	$ 40.00		$ (981,930)
Prior Year Total Contracts as of March 31, 2004					
Natural Gas	Purchase	34,400	$ 4.69	$ 160,700	$ 44,500
Natural Gas	Sale Option	4,643,900	$ 4.24		$ -
Natural Gas	Purchase Option	1,681,000	$ 5.11		$ (529,500)
Crude Oil	Sale Option	88,600	$ 31.63		$ (236,600)

The maximum term over which PDC is managing exposure to the variability of cash flows for commodity price risk is 19 months.

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

The average NYMEX closing price for natural gas for the first quarter of 2005 and the year 2004 was $6.27 Mmbtu and $6.14 Mmbtu. The average NYMEX closing price for oil for the first quarter of 2005 and the year 2004 was $47.90 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 Annual Report on Form 10-K/A for the year ended December 31, 2004, the Company determined that, as of the end of the 2004 fiscal year, 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 March 31, 2005, the Company's Chief Executive Officer and Chief Financial Officer concluded that the Company disclosure controls and procedures were not effective. Management had previously concluded that the Company's disclosure controls and procedures were effective as of March 31, 2005. However, in connection with the restatement of the Company's quarterly condensed consolidated financial statements as of and for the quarter ended March 31, 2005, as fully described in Note 10 of the financial statements, management determined that the material weaknesses described below existed as of March 31, 2005.

Material Weaknesses in Internal Control Over Financial Reporting

The following items were corrected in this amended Form 10-Q.

- The Company revised its accounting for its derivative transactions, primarily due to the reasons set forth below. The Company used hedge accounting for derivative positions that did not qualify for hedge accounting. These errors began in the first quarter of 2001, the effective date of FAS 133, and continued through the first quarter of 2005.

a. The Company did not have sufficient documentation required for these derivatives to qualify for hedge accounting treatment and did not test them periodically for effectiveness as required by FAS 133.

b. The Company did not record the fair value of certain natural gas purchases and sales contracts which were deemed to be derivatives on its consolidated balance sheet, and changes in fair value were not recorded in earnings.

c. The Company reported the fair value of derivative transactions entered into on behalf of its affiliated partnerships on the balance sheet net of the amount due to/from the partnerships. The fair value of these derivative transactions should have been reported at gross.

- The Company revised its accounting for oil and gas properties primarily due to the following reasons.

a. The Company's division of its oil and gas properties into fields for calculation of depreciation and depletion and for the determination of impairments was not consistent with applicable rules in FAS 19. According to FAS 19, a field is defined to be "an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition". In accounting for its oil and gas properties, the Company included areas that should have been treated as separate fields as part of a single field. The financial impacts of corrections to divide the Company's oil and gas properties into revised fields were included in this restated financial statement.

b. It was determined that certain policies and procedures the Company followed for calculating quarterly depreciation were incorrect. The Company utilized the previous annual oil and gas reserve reports to estimate quarterly depreciation and adjusted the yearly depreciation based upon the new oil and gas reserve report at the end of the next year. However, each interim period's depreciation must stand on its own and should not be adjusted at the year end upon the issuance of a new oil and gas reserve report. The financial impacts of corrections to calculate each interim period's depreciation on its own were included in this restated financial statement.

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c. The Company also used its proved developed reserves, as defined by Securities and Exchange Commission rules, to calculate depreciation. The Company's proved developed reserves included the anticipated recompletion of the Codell formation in Wattenberg Field in Colorado as well as behind pipe zones in the Appalachian Basin. After reviewing the rules, the Company concluded that both the future estimated costs and the reserves from these "behind pipe reserves" should be excluded in calculating the depreciation amounts. This change resulted in increases in depreciation compared to the method previously used by the Company until the recompletions and behind pipe reserves are completed. The financial impacts of corrections to exclude both the future estimated costs and the reserves from these "behind pipe reserves" in calculating depreciation amounts were included in this restated financial statement.

- The Company revised its accounting for its asset retirement obligations due to the following reason.

a. The Company interpreted FAS No. 143 as requiring the recording of a liability based on the probable occurrence of certain conditional future events. The Company incorrectly based its estimates of future disposal costs of wells on its historical record of disposing of its wells in ways that transferred asset retirement costs to other parties. The Company has concluded that a liability should be recognized when a legal obligation exists, regardless of conditional future events, and that the full fair value of potential future disposal costs should have been recorded despite the Company's historical practice of transferring most of the obligation to other parties. This error began in the first quarter of 2003, the effective date of FAS No.143, and continued through the first quarter of 2005 and is being corrected through this restatement.

- The Company revised its accounting for its provision for income taxes in its financial statements due to the following reason.

a. The Company incorrectly determined the portion of percentage depletion of oil and gas properties for tax purposes which was treated as a permanent difference in the calculation of its tax provision, and incorrectly determined the classification of certain accrued and deferred income tax balances.

Remediation of Material Weaknesses in Internal Control

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

As previously reported, there was no change in our internal control over financial reporting during the quarter ended March 31, 2005, that materially affects, or is reasonably likely to materially affect, our internal control over financial reporting. However, subsequent to June 30, 2005, we are in the process of implementing the remedial actions described above.

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

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None.

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

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None.

Item 6. Exhibits

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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.
Section 1350 Certification by Chief Executive Officer and Chief Financial Officer	32.1	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:	December 23, 2005	/s/ Steven R. Williams
		Steven R. Williams
		Chief Executive Officer
Date:	December 23, 2005	/s/ Darwin L. Stump
		Darwin L. Stump
		Chief Financial Officer