PETROLEUM DEVELOPMENT CORP
Form 10-Q
November 09, 2006

CONFORMED COPY

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-Q

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

the Securities Exchange Act of 1934

For the period ended September 30, 2006

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 [X] No [ ]

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 14,772,129 shares of the Company's Common Stock ($.01 par value) were outstanding as of October 30, 2006.

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes [ ] No [X]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer" and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated Filer [ ] Accelerated filer [X] Non-accelerated filer [ ]

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

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PART I - FINANCIAL INFORMATION

Item 1. Financial Statements (unaudited)

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders

Petroleum Development Corporation:

We have reviewed the accompanying condensed consolidated balance sheet of Petroleum Development Corporation and subsidiaries as of September 30, 2006, the related condensed consolidated statements of income for the three-month and nine-month periods ended September 30, 2006 and 2005, the related condensed consolidated statement of stockholders' equity for the nine-month period ended September 30, 2006, and the related condensed consolidated statements of cash flows for the nine-month periods ended September 30, 2006 and 2005. 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 the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Petroleum Development Corporation and subsidiaries as of December 31, 2005, 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 May 24, 2006, 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 two 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, 2005, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

As discussed in note 13 to the condensed consolidated financial statements, the Company has restated the condensed consolidated statement of income for the three and nine-month periods ended September 30, 2005.

KPMG LLP

Pittsburgh, Pennsylvania

November 9, 2006

Petroleum Development Corporation

Condensed Consolidated Balance Sheets

(in thousands, except share and per share data)

	September 30, 2006 (Unaudited)	December 31, 2005
Assets		
Current assets:		
Cash and cash equivalents	$ 8,220	$ 90,110
Restricted cash	3,571	1,501
Accounts receivable	41,847	49,779
Accounts receivable - affiliates	1,987	7,234
Inventories	4,008	5,055
Fair value of derivatives	8,729	10,382
Other current assets	13,717	4,640
Total current assets	82,079	168,701
Properties and equipment, net	389,754	277,158
Designated cash - property acquisitions	300,000	-
Other assets	1,589	3,226
Total Assets	$ 773,422	$ 449,085
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued expenses	$ 107,289	$ 107,762
Fair value of derivatives	3,616	18,425
Advances for future drilling contracts	10,351	49,999
Funds held for future distribution	18,946	18,346
Total current liabilities	140,202	194,532
Long-term debt	85,000	24,000
Deferred gain on sale of leaseholds	25,600	-
Other liabilities	7,002	7,116
Deferred income taxes	139,375	26,889
Asset retirement obligation	9,224	8,283
Total liabilities	406,403	260,820
Commitments and contingent liabilities		
Stockholders' equity:		
Common stock, par value $.01 per share; authorized 50,000,000 shares; issued 16,140,225 shares and issued and outstanding 16,281,923 shares	161	163
Additional paid-in capital	20,579	30,423
Retained earnings	388,765	158,504
Unamortized stock award	-	(825)
Treasury stock, at cost - 1,035,089 shares	(42,486)	-
Total stockholders' equity	367,019	188,265
Total Liabilities and Stockholders' Equity	$ 773,422	$ 449,085

See accompanying notes to condensed consolidated financial statements.

Petroleum Development Corporation

Condensed Consolidated Statements of Income

(Unaudited; in thousands except per share data)

	Three Months Ended September 30, 2006	2005 (Restated)(1)	Nine Months Ended September 30, 2006	2005 (Restated)(1)
Revenues:				
Oil and gas well drilling operations (2)	$ 2,659	$ 32,267	$ 11,682	$ 85,744
Gas sales from marketing activities	30,374	14,970	101,445	58,409
Oil and gas sales	29,663	28,414	86,139	68,620
Well operations and pipeline income	2,530	2,291	7,306	6,286
Other	1,964	7	1,986	3,079
Total revenues	67,190	77,949	208,558	222,138
Costs and expenses:				
Cost of oil and gas well drilling operations (2)	4,257	28,734	11,888	73,121
Cost of gas marketing activities	29,883	14,269	100,121	58,349
Oil and gas production and well operations cost	9,961	6,379	23,627	15,067
Exploration cost	940	136	3,735	5,000
General and administrative expense	4,423	1,646	13,070	4,528
Depreciation, depletion, and amortization	8,322	5,120	22,554	14,822
Total costs and expenses	57,786	56,284	174,995	170,887
Gain on sale of leaseholds (3)	328,000	-	328,000	6,216
Income from operations	337,404	21,665	361,563	57,467
Interest income	3,427	202	4,159	621
Interest expense	(34)	(26)	(232)	(88)
Oil and gas price risk management gain (loss), net	2,912	(9,922)	8,714	(12,723)
Income before income taxes	343,709	11,919	374,204	45,277
Income taxes	132,795	4,413	143,943	16,753
Net income	$ 210,914	$ 7,506	$ 230,261	$ 28,524
Basic earnings per common share	$ 13.44	$ 0.46	$ 14.47	$ 1.74
Diluted earnings per common share	$ 13.38	$ 0.46	$ 14.40	$ 1.73

(1) See Note 13.
(2) See Note 12.
(3) See Note 14.

See accompanying notes to condensed consolidated financial statements.

Petroleum Development Corporation

Condensed Consolidated Statement of Stockholders' Equity

(Unaudited, dollars in thousands)

	Common Stock Issued						
	Number of Shares	Amount	Additional Paid-In Capital	Retained Earnings	Treasury Stock at Cost	Unamortized Stock Award	Total
Balance, December 31, 2005	16,281,923	$ 163	$ 30,423	$ 158,504	$ -	$ (825)	$ 188,265
Reclassification of unearned compensation pursuant to SFAS 123(R) adoption	-	-	(825)	-	-	825	-
Exercise of stock options	8,000	-	31	-	-	-	31
Issuance of stock awards	113,207	1	(1)	-	-	-	-
Forfeiture of stock awards	(4,736)	-	-	-	-	-	-
Stock-based compensation expense	-	-	1,101	-	-	-	1,101
Purchase of treasury stock	-	-	-	-	(52,639)	-	(52,639)
Treasury stock retirement	(258,169)	(3)	(10,150)	-	10,153	-	-
Net income	-	-	-	230,261	-	-	230,261
Balance, September 30, 2006	16,140,225	$ 161	$ 20,579	$ 388,765	$ (42,486)	$ -	$ 367,019

See accompanying notes to condensed consolidated financial statements.

Petroleum Development Corporation

Condensed Consolidated Statements of Cash Flows

(Unaudited, in thousands)

	Nine Months Ended September 30, 2006	2005
Cash flows from operating activities:		
Net income	$ 230,261	$ 28,524
Adjustments to net income to reconcile to cash (used in)provided by operating activities:		
Deferred income taxes	112,486	6,684
Depreciation, depletion & amortization	22,554	14,822
Accretion of asset retirement obligation	380	345
Dry hole costs	1,769	5,000
Gain from sale of leaseholds	(328,000)	(6,216)
Gain from sale of assets	(64)	(1,654)
Expired and abandoned leases	24	396
Amortization of stock award	1,101	427
Unrealized (gain) loss on derivative transactions	(7,305)	9,416
Increase in restricted cash	(2,070)	(950)
Increase in current assets	(968)	(16,411)
Increase in other assets	(90)	(1,205)
(Decrease) increase in current liabilities	(43,396)	6,043
Increase (decrease) in other liabilities	3,412	(463)
Net cash (used in) provided by operating activities	(9,906)	44,758
Cash flows from investing activities:		
Capital expenditures	(135,017)	(53,969)
Proceeds from sale of leaseholds	353,600	6,216
Increase in designated cash for property acquisitions	(300,000)	-
Proceeds from sale of leases to partnerships	1,184	1,575
Proceeds from sale of assets	17	3,365
Net cash used in investing activities	(80,216)	(42,813)
Cash flows from financing activities:		
Proceeds from debt	232,000	54,000
Retirement of debt	(171,000)	(61,000)
Payment of debt issuance costs	(160)	-
Proceeds from stock option exercises	31	-
Purchase of treasury stock	(52,639)	(7,879)
Net cash provided by (used in) financing activities	8,232	(14,879)
Net decrease in cash and cash equivalents	(81,890)	(12,934)
Cash and cash equivalents, beginning of period	90,110	77,735
Cash and cash equivalents, end of period	$ 8,220	$ 64,801
Supplemental disclosures of cash flow information:		
Cash paid during the period for:		
Income taxes	$ 46,478	$ 7,050
Interest	$ 280	$ 436

See accompanying notes to condensed consolidated financial statements.

Petroleum Development Corporation

Notes to Condensed Consolidated Financial Statements

September 30, 2006

(Unaudited)

1. General

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Petroleum Development Corporation, together with its subsidiaries, (the Company) is an independent energy company engaged primarily in the exploration, development, production and marketing of natural gas and oil. Since it began oil and gas operations in 1969, the Company has grown primarily through exploration and development activities, the acquisition of producing natural gas and oil wells and the expansion of its natural gas marketing activities.

The accompanying condensed consolidated financial statements have been prepared without audit in accordance with accounting principles generally accepted in the United States of America for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the Securities and Exchange Commission (SEC). Accordingly, pursuant to such rules and regulations, certain notes and other financial information included in audited financial statements were condensed or omitted. In the opinion of management, the condensed consolidated financial statements contain all adjustments (consisting of only normal recurring adjustments) necessary to present fairly the Company's financial position, results of operations and cash flows for the interim periods presented. The interim results of operations for the nine months ended September 30, 2006, and the interim cash flows for the same interim period, are not necessarily indicative of the results to be expected for the full year or any other future period.

The accompanying unaudited condensed consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2005, as filed with the SEC on May 31, 2006.

As described in the Company's Annual Report on Form 10-K for the year ended December 31, 2005, the Company restated its condensed consolidated statements of income for each of the quarterly periods ended March 31, 2005, June 30, 2005, and September 30, 2005. The restatement was to correct certain revenues and expenses to properly reflect the elimination of transactions between the Company and Company-sponsored limited partnerships. The corrections resulted in the reduction of revenues and expenses of equal amounts. The restatement had no effect on income from operations, net income, earnings per share, cash flows, proved oil and gas reserves or the Company's financial position. Only those amounts described below reclassifying amounts to conform to current periods presentation have changed subsequent to the Company filing its 2005 Annual Report on Form 10-K. See Note 13 for further disclosure.

Certain prior period amounts were reclassified to conform to the current presentation. The reclassifications had no impact on reported net earnings, earnings per share or stockholders' equity. Accretion expense related to the Company's asset retirement obligation in the amount of $0.2 million, $0.1 million and $0.3 million for the six months ended June 30, 2006, and the three months and nine months ended September 30, 2005, respectively, has been reclassified from interest expense, a non-operating expense, to oil and gas production and well operations cost, a component of income from operations. Interest income in the amount of $0.7 million, $0.2 million and $0.6 million for the six months ended June 30, 2006, and the three months and nine months ended September 30, 2005, respectively, has been reclassified from other revenue, a component of income from operations, to interest income, a non-operating income. As a result of these reclassifications, income from operations decreased by corresponding amounts with no impact on net income. Additionally, a gain from sale of leaseholds in the amount of $6.2 million for the nine months ended September 30, 2005, has been reclassified from other revenue to gain on sale of leaseholds with no impact on income from operations.

2. Accounting Policies

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Restricted Cash

In July 2006, the Company established a trust in the amount of $300 million with a qualified intermediary in conjunction with its sale of undeveloped leaseholds and corresponding "like-kind exchange" agreement. As of September 30, 2006, $300 million remains in the trust and is reflected in designated cash as a non-current asset in the condensed consolidated balance sheet. Interest earned on the trust account of $3.0 million is reflected in restricted cash as a current asset and will be available to the Company for operating purposes in January 2007 and is not subject to a like-kind exchange. See Note 14 for further disclosure. Additionally, the Company is required to maintain margin deposits with brokers for outstanding derivative contracts. As of September 30, 2006, and December 31, 2005, cash in the amount of $0.6 million and $1.5 million, respectively, was on deposit.

Revenue Recognition

The Company's drilling segment recognizes revenue from our drilling contracts with our sponsored drilling programs using the percentage of completion method based upon the percentage of contract costs incurred to date to the estimated total contract costs for each contract. The Company utilizes this method since reasonably dependable estimates of the total estimated costs can be made and recognized revenues are subject to revisions as a contract progresses, the term of which can range from three to twelve months. In addition, the Company offers its drilling services under two types of contractual arrangements, cost-plus or footage-based service contracts, which result in differing risk and reward relationships, and hence, different revenue reporting policies pursuant to EITF 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent.*

The first cost-plus drilling service arrangement was initially entered into in late 2005 with drilling activity commencing in the first quarter of 2006. Although the Company acts as a principal in the transaction and takes title to products and services acquired necessary for drilling, the Company acts as an agent, with little risk of loss during the performance of the drilling activities. Consistent with the provisions of EITF 99-19, the Company's services provided under the cost-plus drilling agreements are reported net of recovered costs. The Company entered into its second cost-plus drilling arrangement in September 2006 and commenced drilling immediately. It is the Company's intent that all future drilling arrangements will be on a cost-plus basis.

Footage-based contracts provide for the drilling, completion and equipping of wells at footage rates and are 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 and accordingly has risk of loss in performing services under these arrangements. As such, the Company reports revenue under these agreements gross of related expenses. Anticipated losses, if any, on uncompleted contracts are recorded at the time that our estimated costs exceed the estimated contract revenue. As of September 30, 2006, the loss contract reserve was $0.4 million.

Natural gas marketing is reported on the gross accounting method. Riley Natural Gas (RNG), 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. RNG 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 RNG takes title to the gas it purchases from the various producers and bears the risks and rewards of that ownership. Both the realized and unrealized gains or losses of the RNG 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 contract 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 are 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 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.

Stock Based Compensation

The Company accounts for stock based compensation pursuant to SFAS 123(R) - *Share Based Payment.* SFAS 123(R), which requires an entity to recognize at the grant date, the fair value of stock options and other equity based compensation issued to employees in the statement of income. The value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service periods in the Company's consolidated statements of income. Compensation expense attributable to awards granted prior to the adoption of SFAS 123(R) is recognized over the requisite service period for each separately vesting portion and awards granted subsequent to the adoption are recognized using the straight-line method over the vesting period of the entire award.

The Company utilizes a Black-Scholes option pricing model to measure the fair value of stock options granted to employees. The Company's determination of fair value of share-based payment awards on the date of grant using the model is affected by the Company's stock price as well as assumptions regarding a number of highly complex and subjective variables. These variables include, but are not limited to the Company's expected stock price volatility over the expected term of the awards, and actual and projected employee stock option exercise behaviors. In addition, forfeitures are required to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates. Although the fair value of employee stock options is determined in accordance with SFAS 123(R) and SAB 107 using a Black-Scholes option-pricing model, that value may not be indicative of the fair value observed in a willing buyer/willing seller market transaction. The Company is responsible for determining the assumptions used in estimating the fair value of its share-based payment awards.

3. Recent Accounting Pronouncements

Recently Issued Accounting Standards

In September 2006, the FASB issued SFAS No. 157, *Accounting for Fair Value Measurements*. SFAS No. 157 defines fair value, establishes a framework for measuring fair value within generally accepted accounting principles (GAAP) and expands required disclosure about fair value measurements. SFAS 157 does not expand the use of fair value in any new circumstances. The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Company does not expect the new standard to have any material impact on its consolidated financial statements.

In September 2006, the Staff of the Securities and Exchange Commission issued Staff Accounting Bulletin (SAB) No. 108, *Financial Statements - Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*. SAB 108 provides guidance on how prior year misstatements should be taken into consideration when quantifying misstatements in current year financial statements for purposes of determining whether current year's financial statements are materially misstated. SAB 108 requires registrants to quantify misstatements using both an income statement ("rollover") and balance sheet ("iron curtain") approach and evaluate whether either approach results in a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. If prior year errors that had been previously considered immaterial now are considered material based on either approach, no restatement is required so long as management properly applied its previous approach and all relevant facts and circumstances were considered. If prior years are not restated, the cumulative effect adjustment is recorded in opening accumulated earnings as of the beginning of the fiscal year of adoption. SAB 108 is effective for fiscal years ending on or after November 15, 2006, with earlier adoption encouraged. The Company does not expect SAB 108 to have a material impact on its consolidated financial statements.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement 109*, which prescribes a comprehensive model for accounting for uncertainty in tax positions. FIN 48 provides that the tax effects from an uncertain tax position can be recognized in our financial statements, only if the position is more likely than not of being sustained on audit by the Internal Revenue Service, based on the technical merits of the position. The provisions of FIN 48 will become effective for the Company as of January 1, 2007. The cumulative effect, if any, of applying the provisions of FIN 48 will be accounted for as an adjustment to retained earnings. The Company is currently evaluating the impact of adopting FIN 48 on its consolidated financial statements.

Recently Adopted Accounting Standards

In June 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections - a replacement of APB Opinion No. 20 and FASB Statement No. 3*, which replaces Accounting Principles Board Opinion (APB) No. 20, "Accounting Changes", and SFAS 3, "Reporting Accounting Changes in Interim Financial Statements", and changes the requirements for the accounting for and reporting of a change in accounting principle. SFAS 154 requires retrospective application for voluntary changes in accounting principle unless it is impracticable to do so, and it applies to all voluntary changes in accounting principle in addition to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The adoption of the provisions of SFAS 154 in the first quarter of 2006 did not have a material impact on the Company's condensed consolidated financial statements.

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On January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123(R), *Share-Based Payment*, to account for stock-based employee compensation. See Note 5 to condensed consolidated financial statements for a discussion of the adoption of SFAS 123(R) and its impact on the Company's condensed consolidated financial statements.

4. Earnings Per Share

Computation of earnings per common and common equivalent share is as follows for the three and nine months ended September 30, 2006 and 2005: (in thousands, except for per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Weighted average common shares outstanding	15,690	16,272	15,913	16,434
Dilutive effect of share-based compensation:				
Unamortized portion of restricted stock	20	7	16	4
Stock options	54	54	59	47
Weighted average common and common equivalent shares outstanding	15,764	16,333	15,988	16,485
Net income	$ 210,914	$ 7,506	$ 230,261	$ 28,524
Basic earnings per common share	$ 13.44	$ 0.46	$ 14.47	$ 1.74
Diluted earnings per common share	$ 13.38	$ 0.46	$ 14.40	$ 1.73

For the three and nine months ended September 30, 2006, the effects of stock options representing 20,354 common shares were excluded from the calculation of diluted earnings per share as their inclusion would have been antidilutive. For the three and nine months ended September 30, 2005, there were no stock options excluded from the calculation of diluted earnings per share.

5. Stock-Based Compensation

On January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123 (revised 2004), *Share - Based Payment* (SFAS 123(R)), to account for stock-based employee compensation. Among other items, SFAS 123(R) eliminates the use of APB Opinion No. 25 (APB 25) and the intrinsic value method of accounting for equity compensation and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards in their financial statements. We elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in our financial statements over the remaining requisite service period for each separately vesting portion. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense, based on the fair value on the date of grant or modification, will be recognized in our financial statements on a straight-line basis over the vesting period for the entire award. To the extent compensation cost relates to employees directly involved in oil and natural gas acquisition, exploration and development activities, such amounts are capitalized to properties and equipment. Amounts not capitalized to properties and equipment are recognized in the appropriate cost and expense line item in the statements of income. Prior to the adoption of SFAS 123(R), we followed the intrinsic value method in accordance with APB 25 to account for employee stock-based compensation. Prior period financial statements have not been restated for the adoption of SFAS 123(R) under the modified prospective method.

The adoption of SFAS 123(R) required the unamortized stock award recorded under APB 25 related to stock-based compensation awards as of January 1, 2006, in the amount of $0.8 million to be eliminated against additional paid-in-capital.

Total compensation cost charged against income for the Company's plans was $0.4 million and $1.1 million for the three and nine months ended September 30, 2006, and $0.1 million and $0.3 million for the three and nine months ended September 30, 2005, respectively. Compensation capitalized as part of properties and equipment for the three and nine months ended September 30, 2006, was immaterial.

Prior to January 1, 2006, we accounted for our employee stock options using the intrinsic value method prescribed by APB 25. The table below provides the effect on net income and earnings per share as if the Company had applied the fair value based method recognition provisions of SFAS 123 to record stock-based compensation for the three and nine months ended September 30, 2005:

	Three Months Ended September 30, 2005		Nine Months Ended September 30, 2005	
Net Income:				
As reported	$	7,506	$	28,524
Add: Stock-based compensation expense included in reported net income, net of tax		107		269
Deduct: Total stock-based compensation expense determined under fair value based method for all awards, net of tax		(131)		(340)
Pro forma net income	$	7,482	$	28,453
Basic earnings per common share:				
As reported	$	0.46	$	1.74
Pro forma	$	0.46	$	1.73
Diluted earnings per common share:				
As reported	$	0.46	$	1.73
Pro forma	$	0.46	$	1.73

The fair value of options awarded is estimated using the Black-Scholes option pricing model using the assumptions noted in the following table. Expected volatility is based on the Company's historical volatility. The expected life of an award is estimated using historical exercise behavior data. The risk-free interest rate is based on the U.S. Treasury yields in effect at the time of grant and extrapolated to approximate the expected life of the award. The Company does not expect to pay dividends and is restricted from doing so based on its current credit facility. The Company did not grant any option awards in 2005.

	Nine Months Ended September 30, 2006
Expected volatility	39.5%
Expected life (in years)	5.9
Risk-free interest rate	4.3%
Dividend yield	0%

Weighted-average grant date fair value per share	$19.65

Restricted Stock

The Company began issuing shares of restricted common stock to employees in 2004. The fair value of the awards issued is determined based on the fair market value of the shares on the date of grant. This value is amortized over the vesting period, ratably over four years from the date of grant for employees and three years for directors.

The following table provides a summary of restricted stock activity for the nine months ended September 30, 2006:

	Restricted Shares		Weighted Average Grant-Date Fair Value
Non-vested restricted stock at December 31, 2005	38,430	$	32.68
Granted	113,207		40.50
Vested	(13,758)		27.58
Forfeited	(4,736)		40.05
Non-vested restricted stock at September 30, 2006	$ 133,143	$	39.60

Restricted stock awards granted during the nine months ended September 30, 2006, consist of 82,380 common shares to employees and 30,827 common shares to executive officers and directors of the Company's Board.

As of September 30, 2006, there was $4.3 million of total unrecognized compensation cost related to non-vested restricted stock. The cost is expected to be recognized over a weighted average period of 3.3 years.

Stock Options

The Company granted stock options in previous years under several stock compensation plans. Outstanding options expire ten years from the date of grant and become exercisable ratably over a four year period.

The following table provides information related to stock option activity for the nine months ended September 30, 2006.

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (years)	Aggregate Intrinsic Value (a) (thousands)
Outstanding at December 31, 2005	73,880	$ 11.96		
Granted	20,354	43.74		
Exercised	(8,000)	3.88		
Forfeited or expired	-	-		
Outstanding September 30, 2006	86,234	$ 20.21	5.6	$ 1,775
Exercisable at September 30, 2006	53,220	$ 7.18	3.6	$ 1,741

(a) The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option.

The aggregate intrinsic value of stock options exercised during the nine months ended September 30, 2006, was $0.3 million. There were no options exercised during the nine months ended September 30, 2005.

As of September 30, 2006, there was $0.5 million of total unrecognized compensation cost related to non-vested stock options. The cost is expected to be recognized over a weighted average period of 3 years.

6. Properties and Equipment (in thousands)

	September 30, 2006	December 31, 2005
Properties and Equipment:		
Oil and gas properties (successful efforts method of accounting)	$ 490,264	$ 365,379
Pipelines	12,287	11,512
Transportation and other equipment	8,337	6,383
Land and buildings	4,917	3,981
Construction in progress	7,670	1,509
	523,475	388,764
Less accumulated depreciation, depletion and amortization	133,721	111,606
Properties and equipment, net of accumulated depreciation, depletion and amortization	$ 389,754	$ 277,158

Interest related to the construction of qualifying assets is capitalized as part of the construction cost, which totaled $0.7 million and $1.1 million for the three and nine months ended September 30, 2006, respectively. No interest was capitalized in 2005.

7. Long-Term Debt

The Company has a credit facility with J. P. Morgan and BNP Paribas of $200 million subject to and secured by required levels of oil and gas reserves. The current borrowing base, based upon current oil and gas reserves, is $135 million. Effective September 18, 2006, the Company elected to increase the amount it had activated by $55 million, from $80 million to $135 million. There were no additional changes to the credit facility at this time or throughout 2006. The Company is required to pay a commitment fee of 0.25 to 0.375 percent per annum 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 November 4, 2010. The credit facility agreement contains certain financial covenants which require the Company to maintain a certain current ratio. At September 30, 2006, the Company was not in compliance with the current ratio covenant. The Company has received a waiver from the banks to waive the covenant violation at September 30, 2006.

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 and oil sales to a few customers. The Company sells natural gas to various public utilities, natural gas marketers, industrial and commercial customers.

The Company is 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 2005 or the nine months ended September 30, 2006.

The Company is a party to an exploration agreement with an unaffiliated party. The agreement requires the Company to drill a minimum of 25 wells through June 30, 2007. For each well the Company fails to drill prior to June 30, 2007, the Company will be required to pay liquidated damages equal to $125,000 per un-drilled well, for a maximum contingency of $3.1 million. As of September 30, 2006, no wells have been drilled pursuant to the agreement.

In connection with the Company's sale of undeveloped leaseholds in July 2006, the Company is obligated to either drill 16 wells on specifically identified acreage over the next three years or pay liquidated damages of $1.6 million per un-drilled well for a total contingent obligation of $25.6 million, which is reflected on the condensed consolidated balance sheet as a deferred gain on sale of leaseholds. See Note 14 for additional disclosure related to the sale.

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% contingent repurchase obligation, if requested by investors, is currently approximately $12.8 million. The Company believes it has adequate liquidity to meet this obligation should it arise. During 2005 and the nine months ended September, 2006, the Company paid $0.4 million and $0.5 million, respectively, under this provision for the repurchase of partnership units. No amounts were accrued at December 31, 2005, or September 30, 2006.

The Company's drilling programs dating back to 1996 contain a performance supplement that requires the Company to remit a payment equal to one-half of its share of net revenue from the partnership to the investing partners if certain levels of performance are not met. During each of the nine months ended September 30, 2006 and 2005, the Company paid the partnerships a total of $0.6 million in accordance with the provision. The related accrued liability as of September 30, 2006, was $0.4 million and is included as a component of accrued expenses in the condensed consolidated balance sheet; no amounts were accrued as of December 31, 2005. As of September 30, 2006, based upon current oil and gas reserve reports of the partnerships with this provision, the Company estimates its maximum obligation pursuant to this contingency is $4.2 million.

As managing general partner of 76 partnerships, the Company is liable for any potential casualty losses in excess of the partnership assets and insurance. The Company's management believes the casualty insurance coverage carried by the Company and its subcontractors is adequate to meet this potential liability.

In order to secure the services for certain drilling rigs, the Company made commitments to the drilling contractors which call for a minimum commitment of $24,000 daily for a specified period of time if the Company ceases to use the drilling rigs, an event that is not anticipated to occur, and a maximum commitment of $55,400 daily for a specified period of time for daily use of the drilling rigs. As of September 30, 2006, commitments for these three separate contracts expire in November 2008, July 2009 and May 2010. As of September 30, 2006, the Company has an outstanding minimum commitment for $21.2 million and an outstanding maximum commitment for $54.5 million.

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

9. Common Stock Buyback Program

On January 13, 2006, the Company announced that its Board of Directors authorized the purchase of up to 10% (1,627,500 shares) of the Company's common stock during 2006. Stock purchases under this program were made in the open market or in private transactions, at times and in amounts that management deemed appropriate. The Company was authorized to terminate or limit the stock purchase program at any time. For the nine months ended September 30, 2006, the Company purchased 1,293,258 shares at a cost of $52.6 million ($40.70 average price paid per share), including 100,000 shares from an executive officer of the Company at a cost of $4.1 million ($40.66 price paid per share). On October 20, 2006, the Company completed its January 2006 program, purchasing in the open market throughout October an additional 334,242 shares at a cost of $13.7 million ($40.93 average price paid per share). Total shares purchased pursuant to the program were 1,627,500 common shares at a cost of $66.3 million. All shares purchased in accordance with the program and remaining in treasury stock as reflected in the condensed consolidated balance sheet at September 30, 2006, have subsequently been retired.

On October 16, 2006, the Board of Directors of the Company approved a second 2006 purchase program authorizing the Company to purchase up to 10% (1,477,109 shares) of the Company's then outstanding common stock through April 2008. Stock purchases under this program may be made in the open market or in private transactions, at the time and in amounts that management deems appropriate. The Company may terminate or limit the stock purchase program at any time. No purchases have been made pursuant to this program as of the date of this filing.

10. Business Segments

The Company's operating activities are 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 2,950 wells from which it derives oil and gas working interests. The Company charges Company-sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. All material inter-company accounts and transactions between segments have been eliminated. Segment information for the three and nine months ended September 30, 2006 and 2005, is as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005 (Restated)(3)	2006	2005 (Restated)(3)
REVENUES				
Drilling and development	$ 2,659	$ 32,267	$ 11,682	$ 85,744
Natural gas marketing	30,374	14,970	101,445	58,409
Oil and gas sales	29,663	28,414	86,139	68,620
Well operations and pipeline income	2,530	2,291	7,306	6,286
Unallocated amounts (1)	1,964	7	1,986	3,079
Total	$ 67,190	$ 77,949	$ 208,558 #	$ 222,138

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005 (Restated)(3)	2006	2005 (Restated)(3)
SEGMENT INCOME (LOSS) BEFORE INCOME TAXES				
Drilling and development	$ (1,598)	$ 3,533	$ (206)	$ 12,623
Natural gas marketing	663	759	1,801	250
Oil and gas sales (2)	15,010	9,139	50,774	25,734
Well operations and pipeline income	770	393	1,801	2,705

Unallocated amounts (1)				
General and administrative expense	(4,423)	(1,646)	13,070)	(4,528)
Gain on sale of leaseholds	328,000	-	328,000	6,216
Interest income	3,252	142	3,676	425
Interest expense	(34)	(26)	(232)	(88)
Other	2,069	(375)	1,660	1,940
Total	$ 343,709	$ 11,919	$ 374,204	$ 45,277

SEGMENT ASSETS	September 30, 2006	December 31, 2005
Drilling and development	$ 23,570	$ 89,030
Natural gas marketing	28,453	56,518
Oil & gas sales	361,473	256,621
Well operations and pipeline income	27,692	31,407
Unallocated amounts (1)		
Cash	657	3,383
Designated cash - property acquisitions	300,000	-
Other	31,577	12,126
Total	$ 773,422	$ 449,085

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

(2) Includes exploration costs.

(3) See Note 13 for further discussion.

11. Suspended Well Costs

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The following table provides a summary of capitalized exploratory well costs, included in properties and equipment, for the nine months ended September 30, 2006. (dollars in thousands)

	Amount	Number of Wells
Beginning balance at December 31, 2005	$ 1,918	2
Additions to capitalized exploratory well costs pending the determination of proved reserves	11,039	11
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(12,429)	(10)
Capitalized exploratory well costs charged to expense	-	-
Ending balance at September 30, 2006	$ 528	3

At September 30, 2006, none of the wells awaiting the determination of proved reserves have been capitalized for a period greater than one year.

12. Drilling Revenues and Costs of Oil and Gas Drilling Operations

As described in Note 2, the Company changed the type of drilling arrangement it has with its sponsored partnerships. Effective with the last partnership of 2005, which started drilling in the first quarter of 2006, the Company changed from footage-based contracts to cost-plus contracts. The elimination of risk of loss with the new cost-plus contracts does not allow the Company to report revenue for the total contract price of the arrangement but rather only the gross profit from the contract. The new cost-plus contracts impacted the three and nine months ended September 30, 2006, by reducing both drilling revenues and drilling costs for each period by $8.4 million and $34.9 million, respectively.

13. 2005 Restatement

As described in the Company's Annual Report on Form 10-K for the year ended December 31, 2005, we restated our condensed consolidated statements of income for each of the quarterly periods ended March 31, 2005, June 30, 2005, and September 30, 2005. The restatement was to correct certain revenues and expenses to properly reflect the elimination of transactions between the Company and Company-sponsored limited partnerships. The corrections resulted in the reduction of revenues and expenses of equal amounts. The restatement had no effect on income from operations, net income, earnings per share, cash flows, proved oil and gas reserves or the Company's financial position. Only those amounts described in Note 1 reclassifying amounts to conform to current periods presentation have changed subsequent to the Company filing its 2005 Annual Report on Form 10-K.

As presented in our 2005 Form 10-K, the following table sets forth the effect of the restatement on the affected line items within the Company's previously reported condensed consolidated statement of income for the three-month and nine-month periods ended September 30, 2005 (unaudited, in thousands).

	Three Months Ended September 30, 2005		Nine Months Ended September 30, 2005	
Condensed Consolidated Statements of Income Data:	As previously reported	As restated	As previously reported	As restated
Revenues:				
Oil and gas well drilling operations	$ 39,711	$ 32,267	$ 108,118	$ 85,744
Well operations and pipeline income	2,483	2,291	6,840	6,286
Other income (1)	209	209	9,996	9,916
Total revenues	85,787	78,151	251,984	228,975
Costs and expenses:				
Cost of oil and gas well drilling operations	$ 36,178	$ 28,734	$ 95,496	$ 73,121
Oil and gas production and well operations costs (1)	6,455	6,263	15,357	14,722
Total costs and expenses (1)	63,804	56,168	193,551	170,542
Income from operations (1)	$ 21,983	$ 21,983	$ 58,433	$ 58,433

(1) See Note 1 for discussion regarding reclassification of certain revenue and expense amounts.

14. Sale of Undeveloped Leaseholds

On July 20, 2006, the Company sold to an unaffiliated company a portion of its undeveloped leasehold located in Grand Valley Field, Garfield County, Colorado. The sale encompassed 100% of the working interest in approximately 8,700 acres, including approximately 6,400 acres of the Company's Chevron leasehold and 2,300 acres of the Company's Puckett Land Company leasehold. The Company retained approximately 475 undeveloped locations on 10 acre spacing on the Grand Valley Field leasehold in addition to all of its producing properties in the field. The proceeds from the sale were $353.6 million.

During the third quarter of 2006, the Company recorded a gain on sale of leaseholds of $328 million and a deferred gain on sale of leaseholds of $25.6 million. The Company is obligated to either drill 16 wells on specifically identified acreage over the next three years or pay liquidated damages of $1.6 million per un-drilled well. The Company expects to drill the wells for its own benefit and, as such, will record the costs of the wells drilled in accordance with its oil and gas properties accounting policy. For each well the Company drills, the Company will recognize $1.6 million of the deferred gain when drilling is complete. Alternatively, should the Company not first drill the wells, the unaffiliated company has the option to drill the wells for its benefit and, should it decide to exercise its option, with each well drilled, the Company would recognize both $1.6 million of the amount deferred and $0.4 million to be paid to the Company by the unaffiliated company.

In conjunction with the sale, the Company entered into a "like-kind exchange" (LKE) agreement, in accordance with Section 1031 of the Internal Revenue Code, with a "qualified intermediary." Proceeds in the amount of $300 million were transferred directly to the qualified intermediary to be held in trust pursuant to the terms of the LKE agreement. The Company has identified and is in the process of evaluating suitable like-kind property. The Company has until January 17, 2007, to close any acquisitions to take advantage of the federal income tax deferral benefits of a LKE transaction.

15. Subsequent Event - Acquisition of Unioil

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On October 19, 2006, the Company entered in an agreement with Unioil, an independent energy company with properties in northern Colorado and southern Wyoming, in which the Company will make a cash tender

offer to acquire all of Unioil's outstanding common shares (9,541,469) for $1.91 per share for a total transaction cost of $18.2 million. Unioil shareholders representing approximately 82% of Unioil's total outstanding common shares have agreed to tender their shares in the offer.

The Company commenced with the tender offer on November 3, 2006, and the offer will remain open for at least twenty business days pursuant to applicable rules of the Securities and Exchange Commission. The offer is subject to the satisfaction of certain customary closing conditions. It is the Company's intent, immediately following the termination of the offering period, to acquire any Unioil common shares not tendered in the offer for cash in the amount equal to the offer price of $1.91 per share. Upon completion of the merger, Unioil will become a wholly-owned subsidiary of the Company. The acquisition does not qualify for treatment as a LKE transaction and for this reason the proceeds from the July 2006 sale of undeveloped leasehold and held in trust pursuant to a LKE agreement, as described in more detail in Note 14 above, will not be used to consummate the transaction.

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

Management Overview

Net income for the three months ended September 30, 2006, was $210.9 million, compared to $7.5 million for the same prior year period, an increase of $203.4 million. Diluted earnings per share for the three months ended September 30, 2006, increased to $13.38 per share from $0.46 per share for the same prior year period. The increase is the result of increased net income, primarily due to the gain on sale of leaseholds, and in part by a decrease in the number of common shares outstanding. See Note 14 to condensed consolidated financial statements.

For the nine months ended September 30, 2006, net income was $230.3 million compared to $28.5 million for the same prior year period, an increase of $201.8 million. Diluted earnings per share for the current nine-month period was $14.40, an increase of $12.67 per share compared to $1.73 per share for the nine months ended September 30, 2005. The increase is the result of increased net income, primarily due to the gain on sale of leaseholds, and in part by a decrease in the number of common shares outstanding.

2005 Restatement

As described in the Company's Annual Report on Form 10-K for the year ended December 31, 2005, we restated our condensed consolidated statements of income for each of the quarterly periods ended March 31, 2005, June 30, 2005, and September 30, 2005. The restatement was to correct certain revenues and expenses to properly reflect the elimination of transactions between the Company and Company-sponsored limited partnerships. The corrections resulted in the reduction of revenues and expenses of equal amounts. The restatement had no effect on income from operations, net income, earnings per share, cash flows, proved oil and gas reserves or the Company's financial position. Only those amounts described in Note 1 to condensed consolidated financial statements reclassifying amounts to conform to current periods presentation have changed subsequent to the Company filing its 2005 Annual Report on Form 10-K. See Note 13 to condensed consolidated financial statements.

Results of Operations

Three Months Ended September 30, 2006, Compared to Three Months Ended September 30, 2005

Revenues

Total revenues for the three months ended September 30, 2006, were $67.2 million compared to a restated $77.9 million for the same prior year period, a decrease of $10.7 million or 13.7%. The decrease was primarily attributable to a decline in drilling revenues of $29.6 million, partially offset by an increase in oil and gas sales from gas marketing activities of $15.4 million and other revenue of $2.0 million. See Note 12 to the condensed consolidated financial statements and the discussion below titled "Drilling Operations" for the impact the new cost-plus drilling arrangements and related accounting had on our drilling revenues for third quarter 2006.

Costs and Expenses

Costs and expenses for the three months ended September 30, 2006, were $57.8 million compared to a restated $56.3 million for the same prior year period, an increase of $1.5 million. The increase was primarily the result of increases in cost of gas marketing activities, oil and gas production and well operations costs, general and administrative expenses, and depreciation, depletion and amortization offset in part by decreased cost of oil and gas well drilling operations. See Note 12 to the condensed consolidated financial statements and the discussion below titled "Drilling Operations" for the impact the new cost-plus drilling arrangements and related accounting had on our drilling expenses for third quarter 2006.

Drilling Operations

Beginning in first quarter 2006, the Company, in addition to its footage-based drilling arrangements, began recognizing revenues for its cost-plus drilling arrangements with its partnerships. The cost-plus drilling arrangements became effective with the private program partnership funded by the Company in late December 2005 and continued in the 2006 partnership funded on September 1, 2006. Revenue from oil and gas well drilling operations for the three months ended September 30, 2006, were $2.7 million, net of $8.4 million of costs related to drilling arrangements accounted for on the cost-plus basis, compared to a restated $32.3 million for the same prior year period, a decrease of $29.6 million. The decrease was due to lower volumes of partnership activity along with the Company's change in type of drilling contract. The Company started third quarter 2006 with advances for future drilling at June 30, 2006, of $6.4 million and the Company completed its first drilling partnership of 2006 in the third quarter 2006 with approximately $90 million in subscriptions and commenced drilling of the partnership wells on September 1, 2006.

The new cost-plus contracts impacted the current year period by reducing drilling revenues and drilling costs by $8.4 million, as outlined in the table below (in millions):

	Three months ended September 30, 2006			2005
	Drilling Service Revenue/Cost	Direct Reimbursed Cost	Revenue/Cost including reimbursement from Partnerships	Drilling Service Revenue/Cost
Oil and gas well drilling operations	$ 2.7	$ 8.4	$ 11.1	$ 32.3
Total revenues	$ 67.2	$ 8.4	$ 75.6	$ 77.9
Cost of oil and gas well drilling operations	$ 4.3	$ 8.4	$ 12.7	$ 28.7

Total costs and expenses	$ 57.8	$ 8.4	$ 66.2	$ 56.3
Income from operations	$ 337.4		$ 337.4	$ 21.7

Cost of oil and gas well drilling operations decreased $24.4 million to $4.3 million for the three months ended September 30, 2006, from a restated $28.7 million in the same prior year period. The decrease was partially due to the Company's revenue reporting for its new cost-plus drilling arrangements, which reduced drilling costs by $8.4 million for the current year period, and an overall reduction in drilling activities with the partnerships as noted above. See Note 12 to condensed consolidated financial statements.

Although the Company changed to cost-plus drilling arrangements with its new partnerships, prior footage-based contracts realized a loss of $1.2 million during the third quarter of 2006. This loss, along with lower volumes of partnership activity, contributed to the loss of $1.6 million in the drilling and development segment for the current year period compared to income of $3.5 million in the prior year period. See Note 10 to condensed consolidated financial statements.

On September 1, 2006, the Company closed, with subscriptions of approximately $90 million, its first 2006 partnership, Rockies Region 2006 Limited Partnership. The Company, as its managing general partner, contributed in cash a total of $38.9 million to the total capital of the partnership. Approximately $118 million, net of program commissions and related expenses, will be available for future drilling activities. Drilling operations commenced on September 1, 2006, and will continue into the first quarter of 2007.

Natural Gas Marketing Activities

Natural gas sales from the marketing activities of Riley Natural Gas (RNG), the Company's gas marketing subsidiary, for the three months ended September 30, 2006, were $30.4 million compared to $15.0 million for the same prior year period, an increase of $15.4 million or 102.7%. The increase was due to higher volumes of natural gas sold and unrealized gains on derivative transactions, which were $1.8 million for the three months ended September 30, 2006, partially offset by lower average sales prices compared to unrealized losses of $16.3 million for the three months ended September 30, 2005. The costs of gas marketing activities for the three months ended September 30, 2006, were $29.9 million compared to $14.3 million for the three months ended September 30, 2005, an increase of $15.6 million or 109.1%. The increase was due to higher volumes of natural gas purchased and unrealized losses on derivative transactions, which were $1.5 million for the three months ended September 30, 2006, partially offset by lower average purchase prices compared to unrealized gains on derivative transactions of $16.3 million for the three months ended September 30, 2005. Income before income taxes for the Company's natural gas marketing subsidiary decreased from a profit of $0.8 million for the three months ended September 30, 2005, to a $0.7 million profit for the three months ended September 30, 2006.

Oil and Gas Sales

Oil and gas sales from the Company's producing properties for the three months ended September 30, 2006, were $29.7 million compared to $28.4 million for the same prior year period, an increase of $1.3 million or 4.6%. The increase was primarily due to increased volumes partially offset by lower average sales prices of natural gas. Oil sales benefited by an increase in both volume and price, whereas a decrease in natural gas price more than offset the increase in volume. The volume of natural gas sold for the three months ended September 30, 2006, was 3.3 Bcf at an average sales price of $6.05 per Mcf compared to 2.7 Bcf at an average sales price of $8.07 per Mcf for the three months ended September 30, 2005. Oil sales were 168,500 barrels at an average sales price of $57.42 per barrel for the three months ended September 30, 2006, compared to 119,000 barrels at an average sales price of $54.66 per barrel for the three months ended September 30, 2005. The increase in natural gas and oil volumes was the result of the Company's increased investment in oil and gas properties, primarily recompletions of existing wells, significant increased number of wells drilled for our own account, and the investment in oil and gas properties we own in our drilling program partnerships.

Oil and Gas Production

The Company's oil and natural gas production by area of operations along with average sales price (excluding derivative gains/losses) is presented below:

	Three Months Ended September 30, 2006			Three Months Ended September 30, 2005		
	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)*	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)*
Appalachian Basin	441	327,499	330,145	1,218	394,982	402,290
Michigan Basin	1,281	355,624	363,310	1,177	379,824	386,886
Rocky Mountains	166,821	2,620,421	3,621,347	116,170	1,941,513	2,638,533
Total	168,543	3,303,544	4,314,802	118,565	2,716,319	3,427,709
Average Sales Price	$ 57.42	$ 6.05	$ 6.87	$ 54.66	$ 8.07	$ 8.29

*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 the Rocky Mountain Region continue to trail prices which we receive for our Appalachian and Michigan gas, which are based upon the New York Mercantile Exchange (NYMEX). The Company's management believes the lower prices in the Rocky Mountain Region, including Colorado, reflect the higher costs to move gas to major market areas compared to Michigan and the Appalachian Basin resulting in lower price compared to the eastern areas. In May 2003, a pipeline expansion project was completed, leading to improved natural gas prices in the region, which reduced 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 2007, we have in place a series of floors and ceilings on a portion of our natural gas production. Under the arrangements, if the applicable index rises above the ceiling price, we pay the counterparty; however, if the index drops below the floor, the counterparty pays us. During the three months ended September 30, 2006, the Company averaged natural gas volumes sold of 1.1 Bcf per month and oil sales of 56,000 barrels per month. The positions in effect as of October 31, 2006, on the Company's share of production by area are shown in the following table.

		Floors		Ceilings	
Month Set	Contract Term	Monthly Quantity Gas-Mmbtu Oil-Barrels	Contract Price	Monthly Quantity Gas-Mmbtu Oil-Barrels	Contract Price
-	-	-	-	-	-

Colorado Interstate Gas (CIG) Based Derivatives (Piceance Basin)					
Mar 2005	Oct-06	42,000	$ 4.50	21,000	$ 7.25
Jul 2005	Oct-06	27,500	5.50	13,750	7.63
Jul 2005	Nov 2006 - Mar 2007	27,500	6.00	13,750	8.40
Feb 2006	Nov 2006 - Mar 2007	60,000	6.50	-	-
Sep 2006	Nov 2006 - Mar 2007	137,500	4.00	-	-
Feb 2006	Apr 2007 - Oct 2007	44,000	5.50	-	-
Sep 2006	Apr 2007 - Oct 2007	194,500	4.50	-	-
NYMEX Based Derivatives - (Appalachian and Michigan Basins)					
Mar 2005	Oct-06	78,000	$ 5.50	39,000	$ 7.40
Jul 2005	Oct-06	61,000	6.25	30,000	8.98
Jul 2005	Nov 2006 - Mar 2007	68,000	7.00	34,000	9.27
Feb 2006	Nov 2006 - Mar 2007	34,000	8.00	-	-
Feb 2006	Nov 2006 - Mar 2007	34,000	8.50	34,000	13.73
Feb 2006	Apr 2007 - Oct 2007	34,000	7.00	-	-
Feb 2006	Apr 2007 - Oct 2007	34,000	7.50	34,000	10.83
Sep 2006	Apr 2007 - Oct 2007	44,400	6.25	-	-
Panhandle Based Derivatives (NECO)					
Mar 2005	Oct-06	150,000	$ 5.00	75,000	$ 8.62
Jul 2005	Nov 2006 - Mar 2007	150,000	6.50	75,000	8.56
Feb 2006	Apr 2007 - Oct 2007	60,000	6.00	-	-
Feb 2006	Apr 2007 - Oct 2007	60,000	6.50	60,000	9.80
Oil-NYMEX Based (Wattenburg/ND)				-	
Sept 2006	Nov 2006 - Oct 2007	12,350	$ 50.00	-	$ -

Oil and Gas Production and Well Operations Costs

Oil and gas production and well operations costs from the Company's producing properties for the three months ended September 30, 2006, were $10.0 million compared to a restated $6.4 million for the three months ended September 30, 2005, an increase of $3.6 million or 56.2%. The increase was primarily attributable to increased production costs and severance and property taxes on the increased volumes and higher sales prices of oil sold, along with the increased number of wells and pipeline activity by the Company. Lifting cost per Mcfe increased from $1.31 to $1.50 per Mcfe which was primarily due to well workovers and production enhancements work performed.

Exploration Cost

For the three months ended September 30, 2006, exploration costs increased to $0.9 million from $0.1 million for the same prior year period. The increase is primarily attributable to an increase of $0.7 million in geological and geophysical (G&G) costs, which relate to an exploratory seismic program initiated in the second quarter of 2006 on the Company's northeast Colorado properties. The Company expects to incur additional G&G costs in the fourth quarter of 2006. For the current quarter, the Company incurred $0.1 million in dry hole costs for wells previously identified as such.

Well Operations and Pipeline Income

Well operations and pipeline income for the three months ended September 30, 2006, was $2.5 million compared to a restated $2.3 million for the same prior year period, an increase of $0.2 million or 8.7%. The 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 Revenues

Other revenues for the three months ended September 30, 2006, was $2.0 million with an immaterial amount for the same prior year period. The increase was due to management fee income from partnership subscriptions related to the partnership closed on September 1, 2006.

General and Administrative Expenses

General and administrative expenses for the three months ended September 30, 2006, were $4.4 million compared to $1.6 million for the same prior year period, an increase of $2.8 million. The increase was due to costs related to the restatement of the Company-sponsored partnerships' financial statements and increased payroll and payroll related costs. The Company expects these costs to remain at current period levels into 2007.

Depreciation, Depletion, and Amortization

Depreciation, depletion, and amortization costs for the three months ended September 30, 2006, increased to $8.3 million from $5.1 million for the same prior year period, an increase of $3.2 million. The increase was due to the 26% increase in production, significant investments, totaling $130.0 million, in oil and gas properties by the Company in the first nine months this year, and increased per unit cost of depreciation, depletion and amortization as a result of rising costs of drilling and equipping wells.

Gain on Sale of Leaseholds

The Company recognized a gain on sale of leaseholds in the amount of $328.0 million for the three months ended September 30, 2006, related to its sale of undeveloped leaseholds in Colorado. See Note 14 to condensed consolidated financial statements. No corresponding amounts were recorded in the three months ended September 30, 2005.

Interest Income

For the three months ended September 30, 2006, interest income increased to $3.4 million from $0.2 million for the same prior year period. The increase was due to interest earned on the investment of cash proceeds from the sale of undeveloped leaseholds.

Interest Expense

Interest expense for the three months ended September 30, 2006, was relatively unchanged compared to the same prior year period. The increase in interest paid was due to rising interest rates on significantly higher average outstanding balances of our credit facility, offset by $0.7 million of capitalized construction period interest in 2006. The Company utilizes its daily cash balances to reduce its line of credit to lower its costs of interest. The average daily outstanding debt balance for the three months ended September 30, 2006, was $35.7 million compared to $8.0 million for the three months ended September 30, 2005.

Oil and Gas Price Risk Management Gain (Loss), Net

For the three months ended September 30, 2006, the Company recorded unrealized gains of $2.8 million and realized gains of $0.1 million compared to unrealized losses of $7.8 million and realized losses of $2.1 million for the same prior year period. The 2006 change is the result of declining natural gas prices. Oil and gas price risk management gain (loss), net is comprised of the change in fair value of oil and natural gas derivatives related to our oil and gas production (this line does not include commodity based derivative transactions related to transactions from marketing activities).

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes increased to 38.6% from 37.0%, because percentage depletion and domestic production activities deductions do not increase proportionately with increases in pre-tax income.

Nine Months Ended September 30, 2006, Compared to Nine Months Ended September 30, 2005

Revenues

Total revenues for the nine months ended September 30, 2006, were $208.6 million compared to a restated $222.1 million for the same prior year period, a decrease of $13.5 million or 6.1%. The decrease was primarily attributable to a decrease in drilling revenues of $74.1 million partially offset by increased oil and gas sales from both gas marketing activities and the Company's share of production. See Note 12 to the condensed consolidated financial statements and the discussion below titled "Drilling Operations" for the impact the new cost-plus drilling arrangements and related accounting had on our drilling revenues for the first nine months of 2006.

Costs and Expenses

Costs and expenses for the nine months ended September 30, 2006, were $175.0 million compared to a restated $170.9 million for the same prior year period, an increase of $4.1 million or 2.4%. The increase was primarily the result of increased cost of gas marketing activities, oil and gas production and well operations cost, general and administrative expenses, and depreciation, depletion and amortization, partially offset by lower cost of oil and gas well drilling operations and exploration costs. See Note 12 to the condensed consolidated financial statements and the discussion below titled "Drilling Operations" for the impact the new cost-plus drilling arrangements and related accounting had on our drilling expenses for the first nine months of 2006.

Drilling Operations

During first quarter 2006, the Company, in addition to its footage-based drilling arrangements, began recognizing revenues for its cost-plus service arrangements with its partnerships. The cost-plus drilling arrangements became effective with the private program partnership funded by the Company in December 2005 and continued in the 2006 partnership funded on September 1, 2006. Revenue from oil and gas well drilling operations for the nine months ended September 30, 2006, was $11.7 million, net of $34.9 million of costs related to drilling arrangements accounted for on the cost-plus basis, compared to a restated $85.7 million for the same period in 2005, a decrease of $74.0 million. The decrease was due to lower volumes of partnership activity along with the Company's change in type of drilling contracts.

The new cost-plus contract impacted the current year period by reducing drilling revenues and drilling costs by $34.9 million, as outlined in the table below (in millions):

	Nine months ended September 30, 2006			2005
	Drilling Service Revenue/Cost	Direct Reimbursed Cost	Revenue/Cost including reimburse-ment from Partnerships	Drilling Service Revenue/Cost
Oil and gas well drilling operations	$ 11.7	$ 34.9	$ 46.6	$ 85.7
Total revenues	$ 208.6	$ 34.9	$ 243.5	$ 222.1
Cost of oil and gas well drilling operations	$ 11.9	$ 34.9	$ 46.8	$ 73.1
Total costs and expenses	$ 175.0	$ 34.9	$ 209.9	$ 170.9
Income from operations	$ 361.6		$ 361.6	$ 57.5

The cost of oil and gas well drilling operations for the nine months ended September 30, 2006, was $11.9 million compared to a restated $73.1 million for the nine months ended September 30, 2005, a decrease of $61.2 million. The decrease in cost is primarily attributable to the Company's revenue reporting for its new cost-plus drilling arrangements, which reduced drilling costs by $34.9 million for the nine months ended September 30, 2006, and an overall reduction in drilling activities with the partnerships as noted above. See Note 12 to condensed consolidated financial statements.

Although the Company changed to cost-plus drilling arrangements with its two recent partnerships, prior footage-based contracts realized a loss of $1.9 million during the first nine months of 2006. This loss, along with lower volumes of partnership activity, contributed to the loss of $0.2 million in the drilling and development segment for the current year period compared to income of $12.6 million in the prior year period. See Note 10 to condensed consolidated financial statements.

On September 1, 2006, the Company completed sales of its first 2006 partnership, Rockies Region 2006 Limited Partnership, with subscriptions of approximately $90 million. The Company, as its managing general partner, contributed in cash a total of $38.9 million to the total capital of the partnership. Approximately $118 million, net of program commissions and related expenses, will be available for future drilling activities. Drilling operations commenced on September 1, 2006, and will continue into the first quarter of 2007.

Natural Gas Marketing Activities

Natural gas sales from the marketing activities of RNG for the nine months ended September 30, 2006, were $101.4 million compared to $58.4 million for the same prior year period, an increase of $43.0 million or 73.6%. The increase was primarily due to unrealized gains on derivative transactions totaling $12.4 million in the current period compared to an unrealized loss of $21.0 million for the prior year period along with higher volumes of natural gas sold at higher average sales prices.

The costs of gas marketing activities for the nine months ended September 30, 2006, were $100.1 million compared to $58.3 million for the same prior year period, an increase of $41.8 million or 71.7%. The increase was primarily due to unrealized losses on derivative transactions of $12.3 million for the nine months ended September 30, 2006, compared to an unrealized gain of $20.1 million for the nine months ended September 30, 2005, along with higher volumes of natural gas purchased for resale at higher average purchase prices. Income before income taxes for the Company's natural gas marketing subsidiary increased from a $0.2 million profit for the prior nine months ended September 30, 2005, to a $1.8 million profit for the nine months ended September 30, 2006.

Oil and Gas Sales

Oil and gas sales from the Company's producing properties for the nine months ended September 30, 2006, were $86.1 million compared to $68.6 million for the same prior year period, an increase of $17.5 million or 25.5%. The increase was primarily due to increased volumes of oil and natural gas and higher average oil sales prices partially offset by lower average natural gas sales prices. The volume of natural gas sold for the current nine-month period was 9.3 Bcf at an average sales price of $6.24 per Mcf compared to 8.1 Bcf at an average price of $6.52 per Mcf for the same prior year period. Oil sales were 475,000 barrels at an average sales price of $59.04 per barrel for the nine months ended September 30, 2006, compared to 331,000 barrels at an average sales price of $47.60 per barrel for the same prior year period. The increase in natural gas and oil volumes was the result of the Company's increased investment in oil and gas properties, primarily recompletions of existing wells, significant increased number of wells drilled for our own account and the investment in oil and gas properties we own in our drilling program partnerships.

Oil and Gas Production

The Company's oil and natural gas production by area of operations along with average sales price (excluding derivative gains/losses) is presented below:

	Nine Months Ended September 30, 2006			Nine Months Ended September 30, 2005		
	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)*	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)*
Appalachian Basin	1,230	1,108,400	1,115,780	3,073	1,238,724	1,257,162
Michigan Basin	3,274	1,067,160	1,086,804	3,391	1,172,638	1,192,984
Rocky Mountains	470,938	7,135,371	9,960,999	324,355	5,698,298	7,644,428
Total	475,442	9,310,931	12,163,583	330,819	8,109,660	10,094,574
Average Sales Price	$ 59.04	$ 6.24	$ 7.08	$ 47.60	$ 6.52	$ 6.80

*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 reducing the local surplus and leading to improved natural gas prices in the region. There is currently a substantial amount of drilling activity in the Rockies and, if future additions to the pipeline system are not made in a timely fashion, it is possible that pipeline constraints could create a local oversupply situation in the future which could mean lower natural gas prices. Like most other producers in the area we rely on major interstate pipeline companies to construct these facilities, so their timing and construction is not within our control. See Management's Discussion and Analysis for the three months ended September 30, 2006, compared to the three months ended September 30, 2005, for a complete schedule of current derivative positions.

Oil and Gas Production and Well Operations Costs

Oil and gas production and well operations costs from the Company's producing properties for the nine months ended September 30, 2006, were $23.6 million compared to a restated $15.1 million for the same prior year period, an increase of $8.5 million or 56.3%. The increase was primarily due to increased production costs and severance and property taxes on the increased volumes and higher sales prices of oil sold, along with the increased number of wells and pipeline activity by the Company. Lifting cost per Mcfe increased from $1.13 to $1.40 per Mcfe was primarily due to well workovers and production enhancement work performed.

Exploration Cost

During the first nine months of 2006, exploration costs decreased $1.3 million to $3.7 million from $5.0 million for the same prior year period. The prior year period included $5.0 million in dry hole costs compared to $1.8 million for the current year period. The current nine-month period includes one dry hole identified and reported in the first quarter of 2006 totaling $1.4 million and an additional $0.4 million related to the dry holes identified in 2005. The Company does not expect to recognize any material additional cost related to these dry wells in future periods. The current nine-month period also includes geological and geophysical (G&G) costs of $1.8 million related to a seismic program initiated on the Company's northeast Colorado properties in the second quarter of 2006. The Company expects to incur additional G&G costs in the fourth quarter of 2006.

Well Operations and Pipeline Income

Well operations and pipeline income for the nine months ended September 30, 2006, was $7.3 million compared to a restated $6.3 million for the same prior year period, an increase of $1.0 million or 15.9%. The increase was primarily 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 Revenues

Other revenues for the nine months ended September 30, 2006, were $2.0 million compared to a restated $3.1 million for the same prior year period, a decrease of $1.1 million. The decrease was primarily due to a decrease in management fee income from partnership subscriptions.

General and Administrative Expenses

General and administrative expenses for the nine months ended September 30, 2006, were $13.1 million compared to $4.5 million for the same prior year period, an increase of $8.6 million. The increase was due to the cost of the Company's financial statement restatement, the restatement of the Company-sponsored partnerships' financial statements and increased payroll and payroll related costs.

Depreciation, Depletion, and Amortization

For the nine months ended September 30, 2006, depreciation, depletion, and amortization expense increased to $22.6 million from $14.8 million in the same prior year period, an increase of $7.8 million or 52.7%. The increase was due to the 20% increase in production, significant investments, totaling $130.0 million, in oil and gas properties by the Company in the first nine months this year, and increased per unit cost of depreciation, depletion and amortization as a result of rising costs of drilling and equipping wells.

Gain on Sale of Leaseholds

Gain on sale of leaseholds for the nine months ended September 30, 2006, was $328.0 million compared to $6.2 million in 2005, an increase of $321.8 million. The increase is primarily attributable to the sale of undeveloped leaseholds in Colorado in the current year period. See Note 14 to condensed consolidated financial statements. The prior year period included a gain of $6.2 million for the sale of a portion of one of the Company's undeveloped leases in Garfield County, Colorado.

Interest Income

For the nine months ended September 30, 2006, interest income increased $3.6 million to $4.2 million compared to the same prior year period. The increase was primarily due to interest income on the investment of cash proceeds from the sale of undeveloped leaseholds.

Interest Expense

Interest expense for the nine months ended September 30, 2006, increased $0.1 million to $0.2 million compared to the same prior year period. The increase in interest paid was due to rising interest rates on significantly higher average outstanding balances of our credit facility, offset in part by $1.1 million of capitalized construction period interest in the first nine months of 2006. 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 nine months ended September 30, 2006, was $21.5 million compared to $3.3 million for the same prior year period.

Oil and Gas Price Risk Management Gain (Loss), Net

For the nine months ended September 30, 2006, our recognized oil and gas price risk management gain, net was $8.7 million comprised of $7.2 million unrealized gains and $1.5 million realized gains compared to a net loss of $12.7 million, consisting of realized losses of $3.4 million and unrealized losses of $9.3 million for the same prior year period. The 2006 change is the result of declining natural gas prices. Oil and gas price risk management gain (loss), net is comprised of the change in fair value of oil and natural gas derivatives related to our oil and gas production (this line does not include commodity based derivative transactions related to transactions from marketing activities).

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes increased to 38.5% from 37.0%, because percentage depletion and domestic production activities deductions do not increase proportionately with increases in pre-tax income.

Liquidity and Capital Resources

The Company funds its operations through a combination of cash flow from operations and use of the Company's credit facility. Operating cash flow is generated by sales of natural gas and oil from the Company's well interests, natural gas marketing, profits from well drilling and operating activities from the Company's 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 revenues exceed drilling costs. The Company utilizes its revolving credit arrangement to meet the cash flow requirements of its operating and investment activities. Such credit arrangements were adequate to meet all cash and liquidity requirements.

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 nine months of 2006, prices for natural gas decreased from the last part of 2005 but were still close to record levels, and future expectations as reflected in NYMEX futures market are for continuing high price levels for the remainder of 2006 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 are generally closely related allowing for differences in the quality and energy content of the gas, the location and distance to market, and other factors. However, it is not uncommon for prices in a particular area to vary from historical relationships. This may 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. Thus, 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 2005 and continue through the first nine months of 2006, although they have fallen somewhat recently. 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.

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 2007, we have in place a series of floors and ceilings on part of our natural gas and oil production. Under the arrangements, if the applicable index rises above the ceiling price, we pay the counterparty; however, if the index drops below the floor, the counterparty pays us. See the section titled "Oil and Gas Derivative Activities" as discussed in our three-month results of operations for a more detailed analysis of the Company's current derivative positions.

The Company uses derivative investments to protect prices for its partners' share of production as well as its own production. Actual wellhead prices will vary based on local contract conditions, gathering and other costs and factors. The Company records the fair value of its partners' share of outstanding derivatives and the partners corresponding obligation or benefit in accounts receivable or other liabilities as appropriate.

Drilling Programs

On September 1, 2006, the Company funded its first 2006 partnership, Rockies Region 2006 Limited Partnership, with subscriptions of approximately $90 million. Upon closing on September 1, 2006, the Company, the managing general partner, contributed in cash a total of $38.9 million for its contribution to the total capital of the partnership. After payment of sales commissions and associated expenses, including a management fee of $1.3 million to the Company, the partnership had a total of approximately $118.0 million available for future drilling. The partnership expects to drill up to 90 or more wells in Colorado and North Dakota. The number of wells ultimately drilled will depend upon the location, depth, and actual cost of each well drilled. Drilling operations commenced on September 1, 2006, and will continue into the first quarter of 2007.

In December 2005, the Company completed sales of its third 2005 partnership, Rockies Region Private Limited Partnership, with subscriptions of approximately $36 million. The Company, the managing general partner, contributed in cash a total of $11.2 million for its capital contribution for the partnership. After payment of sales commissions and associated expenses, including a management fee of $0.5 million to the Company, the partnership had a total of $42.8 million available for future drilling. Drilling operations commenced in the first quarter and continued into the second quarter of 2006. This was the first partnership under the "cost-plus" arrangement (see Note 12). The Company offered and funded two drilling programs in the first half of 2005, and offered and funded its first drilling program for 2006 during its third quarter, resulting in decreased drilling revenues and cash flows from operations for 2006.

The Company invests, as its equity contribution to each drilling partnership, a sum equal to approximately 43% of the aggregate subscriptions received in the current drilling partnership being offered. 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. This repurchase provision is in effect any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), if investors request that the Company repurchase the units and subject to the Company's financial ability to do so. The maximum annual 10% contingent repurchase obligation, if requested by the investors, is currently approximately $12.8 million. The Company has adequate liquidity to meet this obligation. During the first nine months of 2006, the Company paid $0.5 million under this provision for the repurchase of partnership units.

Drilling Activity

During the nine months ended September 30, 2006, the Company and its drilling fund partnerships drilled a total of 137 developmental wells as detailed by field below. Wells labeled as program wells were drilled for the benefit of the Company and its drilling fund partnerships, while wells labeled as non-program were drilled for the benefit of the Company.

	Successful	Dry Hole	Total
Program			
Wattenburg	49	1	50
Piceance	16	-	16
Bakken, ND	1	-	1
	66	1	67
Non Program			
Wattenburg	39	2	41
Piceance	19	-	19
NECO	9	-	9
Michigan	1	-	1
	68	2	70
Total			
Wattenburg	88	3	91
Piceance	35	-	35
NECO	9	-	9
Bakken, ND	1	-	1
Michigan	1	-	1
	134	3	137

Additionally, during the nine months ended September 30, 2006, the Company drilled one exploratory well on its North Dakota Bakken acreage as well as participated in seven exploratory wells on its North Dakota Nesson acreage, all of which have been successful. The Company and a drilling fund partnership drilled one exploratory dry hole in the Red Desert Basin in Wyoming.

Oil and Gas Properties

Costs incurred by the Company in oil and gas property acquisition, exploration and development for the nine months ended September 30, 2006, are presented below: (in thousand)

Acquisition of properties:	
Unproved properties	$ 9,133
Proved properties	514
Development costs	106,666
Exploration costs	13,643
Total costs incurred	$129,956

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Common Stock Buyback Program

On January 13, 2006, the Company announced that its Board of Directors authorized the purchase of up to 10% (1,627,500 shares) of the Company's common stock during 2006. Stock purchases under this program were made in the open market or in private transactions, at times and in amounts that management deems appropriate. For the nine months ended September 30, 2006, the Company purchased 1,293,258 shares at a cost of $52.6 million ($40.70 average price paid per share), including 100,000 shares from an executive officer of the Company at a cost of $4.1 million ($40.66 price paid per share). On October 20, 2006, the Company completed its January 2006 program, purchasing in the open market throughout October an additional 334,242 shares at a cost of $13.7 million ($40.93 average price paid per share). Total shares purchased pursuant to the program were 1,627,500 common shares at a cost of $66.3 million. All shares purchased in accordance with the program and remaining in treasury stock as reflected in the condensed consolidated balance sheet at September 30, 2006, have subsequently been retired.

On October 16, 2006, the Board of Directors of the Company approved a second 2006 purchase program authorizing the Company to purchase up to 10% (1,477,109 shares) of the Company's then outstanding common stock through April 2008. Stock purchases under this program may be made in the open market or in private transactions, at time and in amounts that management deems appropriate. The Company may terminate or limit the stock purchase program at any time. No purchases have been made pursuant to this program as of the date of this filing.

Working Capital

The Company's working capital as of September 30, 2006, is a negative $58.1 million. The Company manages its working capital needs by only drawing from its credit facility of $200 million as liabilities come due and cash is required. At September 30, 2006, the Company had an activated line of credit with an additional borrowing capacity of $50.0 million.

During the nine months ended September 30, 2006, the Company completed one drilling partnership with a total of $90 million in subscriptions. The Company's contribution on September 1, 2006, was $38 million in cash which contributed to the negative working capital noted above. The Company also has $300 million cash in a "like-kind exchange" trust, which is classified in the condensed consolidated balance sheet as a long-term asset since it is designated for oil and gas property acquisitions. At September 30, 2006, the Company has adequate liquidity with the credit facility to meet both its working capital requirements and plans for continued investment in oil and gas well drilling over the next year.

Long-Term Debt

The Company has a credit facility with J. P. Morgan and BNP Paribas of $200 million subject to and secured by required levels of oil and gas reserves. The current borrowing base, based upon current oil and gas reserves, is $135 million. Effective September 18, 2006, the Company elected to increase the amount it had activated by $55 million, from $80 million to $135 million. There were no additional changes to the credit facility at this time or throughout 2006. The Company is required to pay a commitment fee of 0.25 to 0.375 percent per annum 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 November 4, 2010.

As of September 30, 2006, the outstanding balance was $85 million compared to $24 million as of December 31, 2005. The increase of approximately $61 million was related to capital expenditures of approximately $135.0 million and common stock purchased of $52.6 million in the first nine months of 2006. 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 specified working capital and tangible net worth ratios along with a restriction on the payment of dividends. At September 30, 2006, the outstanding balance was subject to a prime rate of 8.25%. The credit facility agreement contains certain financial covenants which require the Company to maintain a certain current ratio. At September 30, 2006, the Company was not in compliance with the current ratio covenant. The Company has received a waiver from the banks to waive the covenant violation at September 30, 2006.

Contractual Obligations and Contingent Commitments

Contractual obligations and contingent commitments and due dates are as follows (in thousands):

		Payments due by period			
Contractual Obligations and Contingent Commitments	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-Term Debt	$ 85,000	$ -	$ -	$ 85,000	$ -
Operating Leases	2,027	408	928	620	71
Drilling Obligations (1)	28,725	3,125	16,000	9,600	-
Asset Retirement Obligations	9,274	50	100	100	9,024
Drilling Rig Commitments	54,549	20,221	31,048	3,280	-
Derivative Agreements (2)	3,716	3,616	100	-	-
Partnership Performance Supplement (3)	4,174	644	2,596	892	42
Other Liabilities	3,911	40	250	250	3,371
Total	$ 191,376	$ 28,104	$ 51,022	$ 99,742	$ 12,508

(1) Represents the Company's obligations to drill. Failure to drill wells as specified in the related agreements will result in the Company having to pay liquidated damages. A total of $25.6 million is accrued and reported on the condensed consolidated balance sheet as deferred gain on sale of leaseholds as of September 30, 2006. See Note 8 to condensed consolidated financial statements.

(2) Amount represents gross liability related to fair value of derivatives. Includes fair value of derivatives for Riley Natural Gas, Petroleum Development Corporation's share of oil and gas production and derivatives contracts entered into by the Company on behalf of the affiliate partnerships as the managing general partner. The Company has a net payable to the partnerships of $2.4 million as of September 30, 2006.

(3) Represents maximum amount the Company would be required to pay to investing partners if certain levels of partnership performance are not met as of September 30, 2006 (see Note 8).

Long-term debt in the above table does not include interest because 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, while pursuing opportunities for operating improvements and cost efficiencies. Management believes that the Company has adequate capital to meet its operating requirements.

Commitments and Contingencies

As managing general partner of 76 partnerships the Company has liability for any potential casualty losses in excess of the partnership assets and insurance. The Company's management believes its and its subcontractors' casualty insurance coverage is adequate to meet this potential liability.

Sale of Undeveloped Leaseholds

On July 20, 2006, the Company sold to an unaffiliated company a portion of its undeveloped leasehold located in Grand Valley Field, Garfield County, Colorado. The sale encompassed 100% of the working interest in approximately 8,700 acres, including approximately 6,400 acres of the Company's Chevron leasehold and 2,300 acres of the Company's Puckett Land Company leasehold. The Company retained approximately 475 undeveloped locations on 10 acre spacing on the Grand Valley Field leasehold in addition to all of its producing properties in the field. The proceeds from the sale were $353.6 million.

During the third quarter of 2006, the Company recorded a gain on sale of leaseholds of $328 million and a "deferred gain on sale of leaseholds" of $25.6 million. The Company is obligated to either drill 16 wells on specifically identified acreage over the next three years or pay liquidated damages of $1.6 million per un-drilled well. The Company expects to drill the wells for its own benefit and, as such, will record the cost of the wells drilled in accordance with its oil and gas properties accounting policy. For each well the Company drills, the Company will recognize $1.6 million of the deferred gain when drilling is complete. Alternatively, should the Company not first drill the wells, the unaffiliated company has the option to drill the wells for its benefit and, should it decide to exercise its option, with each well drilled, the Company would recognize both $1.6 million of the amount deferred and $0.4 million to be paid to the Company by the unaffiliated company.

In conjunction with the sale, the Company entered into a "like-kind exchange" (LKE) agreement, in accordance with Section 1031 of the Internal Revenue Code, with a "qualified intermediary." Proceeds in the amount of $300 million were transferred directly to the qualified intermediary to be held in trust pursuant to the terms of the LKE agreement. The Company has identified and is in the process of evaluating suitable like-kind property. The Company has until January 17, 2007, to close any acquisitions to take advantage of the federal income tax deferral benefits of a LKE transaction.

Acquisition of Unioil

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On October 19, 2006, the Company entered in an agreement with Unioil, an independent energy company with properties in northern Colorado and southern Wyoming, in which the Company will make a cash tender offer to acquire all of Unioil's outstanding common shares (9,541,469) for $1.91 per share for a total transaction cost of $18.2 million. Unioil shareholders representing approximately 82% of Unioil's total outstanding common shares have agreed to tender their shares in the offer.

The Company commenced with the tender offer on November 3, 2006, and the offer will remain open for at least twenty business days pursuant to applicable rules of the Securities and Exchange Commission. The offer is subject to the satisfaction of certain customary closing conditions. It is the Company's intent, immediately following the termination of the offering period, to acquire any Unioil common shares not tendered in the offer for cash in the amount equal to the offer price of $1.91 per share. Upon completion of the merger, Unioil will become a wholly-owned subsidiary of the Company. The acquisition does not qualify for treatment as a LKE transaction and for this reason the proceeds from the July 2006 sale of undeveloped leasehold and held in trust pursuant to a LKE agreement, as described in more detail in Note 14, will not be used to consummate the transaction.

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 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 observation of trends in the industry, and information available from other outside sources, as appropriate. For a more detailed discussion on the application of these and other accounting policies, see "Note 1 - Summary of Significant Accounting Policies" in our annual financial statements and related notes on Form 10-K. Our critical accounting policies and estimates are as follows:

Principles of Consolidation

The accompanying condensed consolidated financial statements include the accounts of Petroleum Development Corporation (PDC) and its wholly owned subsidiaries, Riley Natural Gas and PDC Securities Incorporated. All material intercompany accounts and transactions have been eliminated in consolidation. The Company accounts for its investment in interests in oil and gas limited partnerships under the proportionate consolidation method. Under this method, the Company's financial statements include its pro rata share of assets, liabilities and revenues and expenses respectively of the Company sponsored limited partnerships in which it participates. The Company's proportionate share of all significant transactions between the Company and the Company-sponsored limited partnerships are eliminated.

Revenue Recognition

The Company's drilling segment recognizes revenue from drilling contracts with its sponsored drilling programs using the percentage of completion method. These contracts range in term from three to twelve months after the commencement of drilling. The Company provides geological, engineering, and drilling supervision for the drilling and completion process and uses subcontractors to perform drilling and completion services. Revenues are recognized under the percentage of completion method based upon 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 periodically during the term of the contract, recognized revenues are subject to revisions as the contract progresses. Anticipated losses, if any, on uncompleted contracts are recorded at the time that our estimated costs exceed the estimated contract revenue. As of September 30, 2006, the loss contract reserve was $0.4 million.

The Company offers its drilling services under two types of contractual arrangements, cost-plus fee or footage-based drilling contracts, which result in differing risk and reward relationships and, hence, differing revenue reporting polices.

The first cost-plus drilling service arrangement was initially entered into in late 2005 with drilling activity commencing in the first quarter of 2006. Although the Company acts as a principal in the transaction and takes title to products and services acquired necessary for drilling, the Company acts as an agent, with little risk of loss during the performance of the drilling activities. Consistent with the provisions of EITF 99-19, the Company's services provided under the cost-plus drilling agreements are reported net of recovered costs. The Company entered into its second cost-plus drilling arrangement in September 2006 and commenced drilling immediately. It is the Company's intent that all future drilling arrangements will be on a cost-plus basis.

Our footage-based contracts provide for the drilling, completion and equipping of wells at footage rates and are 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 and accordingly has risk of loss in performing services under these arrangements. As such, the Company reports revenue under these agreements gross of related expenses.

Natural gas marketing is reported on the gross accounting method. RNG 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. RNG 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 RNG takes title to the gas it purchases from the various producers and bears the risks and rewards of that ownership. Both the realized and unrealized gains or losses of the RNG 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 contract 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 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 are 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 covers monthly operating and accounting costs, insurance and other recurring costs. The Company may also receive additional compensation for special non-recurring activities, such as reworks and recompletions.

Valuation of Accounts Receivable

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

Accounting for Derivatives Contracts at Fair Value

The Company uses derivative instruments to manage its commodity and financial market risks. Accounting requirements for derivatives and hedging activities are complex; interpretation of these requirements by standard-setting bodies is ongoing.

Derivatives are reported on the Condensed Consolidated Balance Sheets at fair value. Changes in fair value of derivatives are recorded in earnings in the condensed consolidated statements of income as the Company does not seek to qualify its derivatives for hedge accounting under the provisions of SFAS 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 an impairment test, the Company estimates the future cash flows associated with individual assets or groups of assets. Impairment is 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

The Company accounts for its oil and gas properties under the successful efforts method of accounting. Costs of proved developed producing properties, successful exploratory wells and development dry hole costs 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 independent petroleum engineers annually as of December 31st of each year. The Company adjusts oil and gas reserves for any major acquisitions, new drilling and divestitures during the year as needed.

Exploration costs, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Exploratory well drilling costs, including the cost of stratigraphic test wells, are initially capitalized but charged to expense if the well is determined to be nonproductive. The status of each in-progress well is reviewed quarterly to determine the proper accounting treatment under the successful efforts method of accounting. Exploratory well costs continue to be capitalized as long as the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing its reserves and economic and operating viability. If an in-progress exploratory well is found to be unsuccessful (referred to as a dry hole) prior to the issuance of our financial statements, the costs are expensed to exploratory dry hole costs, which is included in "exploration cost" in the statements of income. If we are unable to make a final determination about the productive status of a well prior to issuance of our financial statements, the well is classified as "Suspended Well Costs" until we have had sufficient time to conduct additional completion or testing operations to evaluate the pertinent geological and engineering data obtained. At the time when we are able to make a final determination of a well's productive status, the well is removed from the suspended well status and the proper accounting treatment is recorded. The determination of an exploratory well's ability to produce is made within one year from the completion of drilling activities.

The acquisition costs of unproved properties are capitalized when incurred, until such properties are transferred to proved properties or charged to expense when expired, impaired or amortized. Unproved oil and gas properties with individually significant acquisition costs are periodically assessed, and any impairment in value is charged to expense. The amount of impairment recognized on unproved properties which are not individually significant is determined by amortizing the costs of such properties within appropriate fields based on the Company's historical experience, acquisition dates and average lease terms. Amortization of remaining lease costs for all other insignificant properties is recorded over the average remaining lives of the leases. The valuation of unproved properties is subjective and requires management of the Company to make estimates and assumptions which, with the passage of time, may prove to be materially different from actual realizable values.

Upon sale or retirement of significant portions of or 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 individual wells, the proceeds are credited to property costs.

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 estimated production based upon prices at which management reasonably estimates such products to be sold. These estimates of future product prices may differ from current market prices of oil and gas. Any downward revisions to management's estimates of future production or product prices could result in an impairment of the Company's oil and gas properties in subsequent periods. 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.

Deferred Tax Asset Valuation Allowance

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

Recent Accounting Pronouncements

Recently Issued Accounting Standards

In September 2006, the FASB issued SFAS No. 157, *Accounting for Fair Value Measurements*. SFAS No. 157 defines fair value, establishes a framework for measuring fair value within generally accepted accounting principles (GAAP) and expands required disclosure about fair value measurements. SFAS 157 does not expand the use of fair value in any new circumstances. The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Company does not expect the new standard to have any material impact on its consolidated financial statements.

In September 2006, the Staff of the Securities and Exchange Commission issued Staff Accounting Bulletin (SAB) No. 108, *Financial Statements - Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*. SAB 108 provides guidance on how prior year misstatements should be taken into consideration when quantifying misstatements in current year financial statements for purposes of determining whether current year's financial statements are materially misstated. SAB 108 requires registrants to quantify misstatements using both an income statement ("rollover") and balance sheet ("iron curtain") approach and evaluate whether either approach results in a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. If prior year errors that had been previously considered immaterial now are considered material based on either approach, no restatement is required so long as management properly applied its previous approach and all relevant facts and circumstances were considered. If prior years are not restated, the cumulative effect adjustment is recorded in opening accumulated earnings as of the beginning of the fiscal year of adoption. SAB 108 is effective for fiscal years ending on or after November 15, 2006, with earlier adoption encouraged. The Company does not expect SAB 108 to have a material impact on its consolidated financial statements.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement 109*, which prescribes a comprehensive model for accounting for uncertainty in tax positions. FIN 48 provides that the tax effects from an uncertain tax position can be recognized in our financial statements, only if the position is more likely than not of being sustained on audit by the Internal Revenue Service, based on the technical merits of the position. The provisions of FIN 48 will become effective for the Company as of January 1, 2007. The cumulative effect of applying the provisions of FIN 48 will be, if any, accounted for as an adjustment to retained earnings. The Company is currently evaluating the impact of adopting FIN 48 on its consolidated financial statements.

Recently Adopted Accounting Standards

In June 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections - a replacement of APB Opinion No. 20 and FASB Statement No. 3*, which replaces Accounting Principles Board Opinion (APB) No. 20, "Accounting Changes", and SFAS 3, "Reporting Accounting Changes in Interim Financial Statements", and changes the requirements for the accounting for and reporting of a change in accounting principle. SFAS 154 requires retrospective application for voluntary changes in accounting principle unless it is impracticable to do so, and it applies to all voluntary changes in accounting principle in addition to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The adoption of the provisions of SFAS 154 in the first quarter of 2006 did not have a material impact on the Company's condensed consolidated financial statements.

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On January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123(R), *Share - Based Payment*, to account for stock-based employee compensation. See Note 5 to condensed consolidated financial statements for a discussion of the adoption of SFAS 123(R) and its impact on the Company's condensed consolidated financial statements.

Disclosure Regarding Forward Looking Statements

This Form 10-Q contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical facts included in and incorporated by reference into this Form 10-Q are forward-looking statements. These forward-looking statements are subject to certain risks, trends and uncertainties that could cause actual results to differ materially from those projected. Among those risks, trends and uncertainties are the Company's estimate of the sufficiency of its existing capital sources, its ability to raise additional capital to fund cash requirements for future operations, the uncertainties involved in estimating quantities of proved oil and natural gas reserves, in successfully drilling productive wells and in prospect development and property acquisitions and in projecting future rates of production, the timing of development expenditures and drilling of wells, its ability to sell its produced natural gas and oil and the prices it receives for its production, its ability to comply with changes in federal, state, local, and other laws and regulations, including environmental policies, and the operating hazards attendant to the oil and gas business. In particular, careful consideration should be given to cautionary statements made in this Form 10-Q, the Company's Annual Report on Form 10-K for the year ended December 31, 2005, and the Company's other SEC filings and public disclosures. The Company undertakes no duty to update or revise these forward-looking statements.

Item 3. Quantitative and Qualitative Disclosure About Market Risk.

Interest Rate Risk

There have been no material changes in the reported market risks faced by the Company since December 31, 2005.

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, NYMEX-traded oil option contracts for Colorado and North Dakota oil production, Panhandle-based contracts traded by BNP Paribas for NECO gas production and CIG-based contracts traded by JP Morgan for other Colorado gas production. 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 derivatives are structured to reduce the Company's exposure to changes in price associated with the derivative commodity, they also limit the benefit the Company might otherwise have received from price changes associated with the derivative commodity. RNG also enters into fixed-price physical purchase and sale agreements that are derivative contracts. 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 fixed-price purchase and sale positions for Riley Natural Gas and Petroleum Development Corporation as of September 30, 2006 and 2005.

Riley Natural Gas
Open Derivative Positions
(in thousands, except average price data)

Commodity	Type	Quantity Gas-Mmbtu	Weighted Average Price	Total Contract Amount	Fair Value
Total Contracts as of September 30, 2006					

Natural Gas	Cash Settled Futures / Swaps Purchases	446	$ 7.39	$ 3,294	$ (768)
Natural Gas	Cash Settled Futures / Swaps Sales	1,956	8.42	16,467	2,519
Natural Gas	Cash Settled Basis Swap Sales	80	0.50	40	23
Natural Gas	Physical Purchases	1,917	8.44	16,176	(1,866)
Natural Gas	Physical Sales	228	6.75	1,539	711
Natural Gas	Physical Basis Purchases	80	0.45	36	(19)
Contracts Maturing in 12 months following September 30, 2006					
Natural Gas	Cash Settled Futures / Swaps Purchases	446	$ 7.39	$ 3,294	$ (768)
Natural Gas	Cash Settled Futures / Swaps Sales	1,518	8.11	12,310	2,165
Natural Gas	Cash Settled Basis Swap Sales	80	0.50	40	23
Natural Gas	Physical Purchases	1,449	8.43	12,212	(1,859)
Natural Gas	Physical Sales	228	6.75	1,539	711
Natural Gas	Physical Basis Purchases	80	0.45	36	(19)
Prior Year Total Contracts as of September 30, 2005					
Natural Gas	Cash Settled Sale	3,444	$ 7.08	$ 24,393	$(18,293)
Natural Gas	Cash Settled Purchase	980	8.12	7,953	4,635
Natural Gas	Cash Settled Sale Option	80	5.56	-	-
Natural Gas	Cash Settled Purchase Option	40	7.06	-	(254)
Natural Gas	Physical Contract Sale	493	7.79	3,844	(3,134)
Natural Gas	Physical Contract Purchase	3,111	7.32	22,785	16,897

The maximum term for the derivative contracts listed above is 28 months.

Petroleum Development Corporation
Open Derivative Positions
(in thousands, except average price data)

Commodity	Type	Quantity Gas-Mmbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Value
Total Contracts as of September 30, 2006					
Natural Gas	Cash Settled Option Sales	3,280	$ 10.00	$ 32,801	$ (917)
Natural Gas	Cash Settled Option Purchases	18,200	5.56	101,190	6,142
Crude Oil	Cash Settled Option Purchases	360	50.00	18,000	(146)

Contracts maturing in 12 months following September 30, 2006								
Natural Gas	Cash Settled Option Sales	3,120	$	9.98	$	31,130	$	(819)
Natural Gas	Cash Settled Option Purchases	16,810		5.58		93,780		5,830
Crude Oil	Cash Settled Option Purchases	330		50.00		16,500		(151)
Prior Year Total Contracts as of September 30, 2005								
Natural Gas	Purchase	30	$	6.82	$	205	$	218
Natural Gas	Sale Option	18,620		6.46		120,263		2,201
Natural Gas	Purchase Option	7,060		8.01		56,532		(25,724)
Crude Oil	Sale Option	90		32.30		2,907		-
Crude Oil	Purchase Option	45		40.00		1,800		(1,172)

The maximum term for the derivative contracts listed above is 13 months.

In addition to including the gross assets and liabilities related to the Company's share of oil and natural gas production, the above tables and the accompanying condensed consolidated balance sheets include the gross assets and liabilities related to derivative contracts entered into by the Company on behalf of the affiliate partnerships as the managing general partner. The accompanying condensed consolidated balance sheets include the fair value of derivatives and a corresponding payable to the partnerships of $2.4 million as of September 30, 2006, and $5.4 million as of December 31, 2005. In addition to the short-term fair value of derivatives shown on the accompanying condensed consolidated balance sheets there is a long-term asset of $0.6 million as of September 30, 2006, and long-term liability of $1.3 million as of December 31, 2005, related to the fair value of derivatives.

The average CIG closing price for natural gas for the first nine months of 2006 and the year 2005 was $5.92 per Mmbtu and $6.95 per Mmbtu, respectively. The average NYMEX closing price for natural gas for the first nine months of 2006 and the year 2005 was $7.45 per Mmbtu and $8.62 per Mmbtu, respectively. The average NYMEX closing price for oil for the nine months of 2006 and the year 2005 was $68.20 per Bbl and $55.34 per Bbl, respectively. 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. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

In connection with the preparation of the Company's Annual Report on Form 10-K for the year ended December 31, 2005 ("2005 10-K"), an evaluation was performed under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act). The Company concluded that control deficiencies in its internal control over financial reporting as of December 31, 2005, constituted material weaknesses within the meaning of the Public Company Accounting Oversight Board's Auditing Standard No. 2.

As reported in Item 9A(c) of the 2005, Form 10-K and Item 4 of its March 31, 2006, and June 30, 2006, Forms 10-Q, the Company determined that the following material weaknesses in internal control over financial reporting existed as of December 31, 2005.

The Company did not have effective policies and procedures, or personnel with sufficient technical expertise, to properly account for derivative transactions in accordance with generally accepted accounting principles. Specifically, the Company's policies and procedures relating to derivatives transactions were not designed effectively to ensure that each of the requirements for hedge accounting was evaluated appropriately with respect to the Company's commodity based derivatives. Additionally, the Company's policies and procedures relating to the derivative transactions entered into on behalf of affiliated partnerships were not adequate to ensure these transactions were recorded properly in the financial statements. As a result, a misstatement was identified in the fair value of derivatives and the oil and gas price risk management loss accounts that was corrected prior to the issuance of the Company's 2005 consolidated financial statements. This deficiency results in more than a remote likelihood that a material misstatement of the Company's annual or interim consolidated financial statements would not be prevented or detected.

The Company did not have effective policies and procedures, or personnel with sufficient technical expertise, to ensure compliance with appropriate accounting principles for its oil and gas properties. Specifically, the Company's policies and procedures were not designed effectively to ensure that the calculation of depreciation, depletion and amortization and the determination of impairments were performed in accordance with the applicable authoritative accounting guidance. As a result, misstatements were identified in the accumulated depreciation, depletion and amortization and the depreciation, depletion and amortization expense accounts that were corrected prior to the issuance of the Company's 2005 consolidated financial statements. This deficiency results in more than a remote likelihood that a material misstatement of the Company's annual or interim consolidated financial statements would not be prevented or detected.

The Company did not have effective policies and procedures, or personnel with sufficient technical expertise, to ensure proper accounting and disclosure for income taxes. Specifically, the Company's policies and procedures did not provide for appropriate control documentation or supervisory review of permanent and temporary differences, or assessment of tax reserves to ensure that they were properly reflected and disclosed in the Company's financial statements. As a result, misstatements were identified in the deferred income tax liability and income tax expense accounts that were corrected prior to the issuance of the Company's 2005 consolidated financial statements. This deficiency results in more than a remote likelihood that a material misstatement of the Company's annual or interim consolidated financial statements would not be prevented or detected.

The Company did not have effective policies and procedures, or personnel with sufficient technical expertise, to ensure that its accounting for asset retirement obligations complied with generally accepted accounting principles. Specifically, the Company's policies and procedures regarding the estimate of the fair value of the asset retirement obligations were not designed effectively to ensure that it was estimated in accordance with SFAS No. 143, *Asset Retirement Obligations*. This deficiency results in more than a remote likelihood that a material misstatement of the Company's annual or interim consolidated financial statements would not be prevented or detected.

The Company did not have effective policies and procedures, or personnel with sufficient technical expertise, to provide for adequate monitoring and assessment of the application of accounting principles, standards or rules as it relates to proportionate consolidation in a timely manner. As a result of this control deficiency, the Company did not appropriately eliminate its proportionate share of transactions with the Company sponsored limited partnerships, which resulted in the restatement of the Company's financial statements for the first three quarters of 2005, the years ended December 31, 2004, 2003, 2002, and 2001 and each of the quarters in 2004 and 2003.

Material weaknesses were identified by the Company and disclosed in its 2005 Form 10-K and its March 31, 2006, and June 30, 2006, Forms 10-Q. Based on the identification of material weaknesses and subsequent evaluations, the

Chief Executive Officer and Chief Financial Officer have concluded that, as of September 30, 2006, the Company's disclosure controls and procedures were not effective, because the previously-identified material weaknesses in internal control over financial reporting have not been determined to be fully remediated. Until such time as the Company can fully implement its changes in internal controls over financial reporting, and such changes have been operational for a sufficient period of time to allow for effective testing, the Company believes that the above material weaknesses continue to exist as of September 30, 2006, and therefore are reported in this Form 10-Q. See discussion of changes and remediation efforts below.

(b) Changes and Remediation in the Company's Internal Control over Financial Reporting

The Company had no material changes in the Company's internal control over financial reporting during the fiscal quarter ended September 30, 2006, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Remediation of Material Weaknesses in Internal Control

Management, with oversight from the Audit Committee of the Board of Directors, has been addressing the material weaknesses disclosed in its 2005 Annual Report on Form 10-K and Item 4 of its subsequently filed Forms 10-Q, and is committed to effectively remediating known weaknesses as expeditiously as possible. Because some remedial steps have not been completed, the Company performed additional analysis and procedures in order to ensure that the condensed consolidated financial statements contained in this Form 10-Q were prepared in accordance with generally accepted accounting principles in the United States. Although the Company's remediation efforts are well underway, the control weaknesses noted above will not be considered remediated until the changes in internal controls over financial reporting are implemented and operational for a sufficient period of time to allow for effective testing and such controls are tested, and management and its independent registered certified public accounting firm conclude that these controls are operating effectively.

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

The Company continued to enhance its financial accounting and reporting team. An additional Certified Public Accountant was hired in the first quarter of 2006 and two additional Certified Public Accountants were hired during the second quarter of 2006, which included a corporate financial reporting director and a partnership reporting director. As previously reported during 2005, the Company enhanced training for its financial accounting and reporting team; additional training has been attended and additional training is being planned for later in 2006.

The Company engaged a team of highly experienced independent advisors, through all fiscal quarters in 2006, to assist with various accounting research, projects and monitoring activities. They assist the Company with accounting and reporting issues including, but not limited to, derivatives, oil and gas activities, new accounting standards or rules, transaction-specific accounting issues, SEC reporting and on-going monitoring of changes that may impact the Company's application of accounting principles.

During the fourth quarter 2005, the Company acquired accounting research software and other accounting technical resources including GAAP and SEC reporting checklists and has utilized these resources throughout 2006 to assist in the preparation of its financial statements and SEC filings. Additionally, the research software has been used as a source of informal training and education in enhancing the technical expertise of the financial accounting and reporting team.

During 2005 and continuing in all fiscal quarters of 2006, the Company reevaluated and corrected its documentation, policies and procedures, and templates with respect to its accounting for derivatives, oil and gas properties, income taxes, asset retirement obligations, proportionate consolidation and the related disclosures in its financial statements. Additionally, the Company is considering and evaluating the potential acquisition of software to assist in automating its SFAS 109, *Accounting for Income Taxes* calculations. The Company plans to make additional improvements during the fourth quarter of 2006.

The Company has evaluated, selected and begun the installation of a third-party integrated oil and gas accounting software system. The Company anticipates full implementation of this system on January 1, 2007.

The Company believes the significant cumulative measures taken to date and the additional remediation planned for the future will address the reported material weaknesses and the Company intends to complete and test these remediation efforts by December 31, 2006. In addition, the Company will continue to develop and implement other initiatives during 2006 that will further improve both the effectiveness and efficiency of the Company's internal control over financial reporting. However, until the Company has fully tested its internal controls, the Company can not make a complete assessment of its internal control over financial reporting.

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 1A. Risk Factors

Our business has many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock are described under "Risks Related to the Oil and Natural Gas Industry and the Company" in Item 1A of our annual report on Form 10-K for the year ended December 31, 2005, as filed with the Securities and Exchange Commission on May 31, 2006. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC. There have been no material changes from the risk factors previously disclosed in the Company's 2005 Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

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(c) Purchases of Equity Securities by the Issuer and Affiliated Purchasers.

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs

July 1 - 31, 2006	70,176	$40.48	70,176	1,299,155
August 1 - 31, 2006	389,307	42.05	389,307	909,848
September 1 - 30, 2006	575,606	40.44	575,606	334,242
Total	1,035,089	$41.05	1,035,089	334,242

In January 2006, the Company announced that its Board of Directors authorized the Company to purchase up to 10% (1,627,500 shares) of its outstanding common stock during 2006. Stock purchases under this program may be made in the open market or in private transactions, at time and in amounts that management deems appropriate. The Company may terminate or limit the stock purchase program at any time. For the nine months ended September 30, 2006, the Company purchased 1,293,258 shares at a cost of $52.6 million ($40.70 average price per share). In October 2006, the Company completed its January 2006 program, purchasing an additional 334,242 shares at a cost of $13.7 million ($40.93 average price per share). It remains the intent of the Company to retire all shares purchased pursuant to the January 2006 program.

On October 16, 2006, the Board of Directors of the Company approved a second 2006 purchase program authorizing the Company to purchase up to 10% (1,477,109 shares) of the Company's then outstanding common stock through April 2008. Stock purchases under this program may be made in the open market or in private transactions, at time and in amounts that management deems appropriate. The Company may terminate or limit the stock purchase program at any time. No purchases have been made pursuant to this program as of the date of this filing.

Item 3. Defaults Upon Senior Securities

None.

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

The following provides a summary of votes cast for the proposals on which our shareholders voted at our Annual Meeting of Shareholders held on September 15, 2006, in Bridgeport, West Virginia.

Proposal No. 1 - Election of two directors to serve three-year terms expiring in 2009.

Nominee	For	Withheld
Kimberly Luff Wakim	14,097,733	278,579
Steven R. Williams	14,232,338	143,974

The following director terms continued after the Annual Meeting of Shareholders.

Director	Term Expiring
Vincent F. D'Annunzio	2007
Thomas E. Riley	2007
David C. Parke	2008
Jeffrey C. Swoveland	2008

Proposal No. 2 - Ratification of KPMG LLP as the Company's Independent Registered Public Accounting Firm for the year ending December 31, 2006.

For	Against	Abstain
13,914,563	435,268	26,483

Item 5. Other Information

None.

Item 6. Exhibits

(a) Exhibits

Exhibit Name	Exhibit Number	Location
Amended and Restated Certificate of Incorporation of the Company	3.1	Incorporated by reference to Exhibit 3.1 to Form S-2 SEC File No. 333-36369 filed on September 25, 1997.
Amended and Restated By-laws of the Company	3.2	Incorporated by reference to Exhibit 3.2 to Form 10-Q SEC File No. 000-07246 filed on August 9, 2006.
Acknowledgement of Independent Registered Public Accounting Firm	23. 1	Filed herewith.
Rule 13a-14(a)/15d-14(a) Certification by Chief Executive Officer	31. 1	Filed herewith.
Rule 13a-14(a)/15d-14(a) Certification by Chief Financial Officer	31. 2	Filed herewith.
Title 18 U.S.C. Section 1350 (Section 906 of Sarbanes-Oxley Act of 2002) Certifications by Chief Executive Officer and Chief Financial Officer of Petroleum Development Corporation	32	Filed herewith.

SIGNATURES

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

Petroleum Development Corporation

(Registrant)

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Date: November 9, 2006

/s/ Steven R. Williams

Steven R. Williams

Chief Executive Officer

Date: November 9, 2006

/s/ Darwin L. Stump

Darwin L. Stump

Chief Financial Officer

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