PETROLEUM DEVELOPMENT CORP
Form 10-Q
August 09, 2007

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 quarterly period ended June 30, 2007

OR

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

Commission File Number 000-07246

PETROLEUM DEVELOPMENT CORPORATION
(Exact name of registrant as specified in its charter)

Nevada	**95-2636730**
(State of incorporation)	**(I.R.S. Employer Identification No.)**

120 Genesis Boulevard
Bridgeport, West Virginia 26330
(Address of principal executive offices) (Zip code)

Registrant's telephone number, including area code: (304) 842-3597

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 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 ¨

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 the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 14,898,285 shares of the Company's Common Stock ($.01 par value) were outstanding as of July 31, 2007.

PETROLEUM DEVELOPMENT CORPORATION

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PART 1 – FINANCIAL INFORMATION

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PART I - FINANCIAL INFORMATION

Item 1. Financial Statements *(unaudited)*

PETROLEUM DEVELOPMENT CORPORATION
Condensed Consolidated Balance Sheets
(in thousands, except share data)

	June 30, 2007	December 31, 2006*
Assets		
Current assets:		
Cash and cash equivalents	$ 21,586	$ 194,326
Restricted cash - current	14,903	519
Accounts receivable, net	47,550	42,600
Accounts receivable - affiliates	13,906	9,235
Inventories	5,775	3,345
Fair value of derivatives	12,785	15,012
Other current assets	15,650	5,977
Total current assets	132,155	271,014
Properties and equipment, net	698,525	394,217
Restricted cash - long term	1,295	192,451
Other assets	4,708	26,605
Total assets	$ 836,683	$ 884,287
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable	$ 81,258	$ 67,675
Short term debt	-	20,000
Production tax liability	14,271	11,497
Other accrued expenses	10,887	9,685
Accounts payable - affiliates	8,943	7,595
Deferred gain on sale of leaseholds	-	8,000
Federal and state income taxes payable	2,145	28,698
Fair value of derivatives	3,692	2,545
Advances for future drilling contracts	3,526	54,772
Funds held for future distribution	44,090	31,367
Total current liabilities	168,812	241,834
Long-term debt	124,000	117,000
Deferred gain on sale of leaseholds	-	17,600
Other liabilities	17,810	19,400
Deferred income taxes	126,557	116,393
Asset retirement obligation	17,459	11,916
Total liabilities	454,638	524,143
Commitments and contingencies		
Minority interest in consolidated limited liability company	792	-
Shareholders' equity:		

Common stock, shares issued:14,893,070 in 2007 and 14,834,871 in 2006		149		148
Additional paid-in capital		908		64
Retained earnings		380,386		360,102
Treasury shares, at cost: 5,158 in 2007 and 4,706 in 2006		(190)		(170)
Total shareholders' equity		381,253		360,144
Total liabilities and shareholders' equity	$	836,683	$	884,287

**Derived from audited 2006 balance sheet.*

See accompanying notes to condensed consolidated financial statements.

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PETROLEUM DEVELOPMENT CORPORATION
Condensed Consolidated Statements of Income
(unaudited; in thousands except per share data)

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006 Revised*	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006 Revised*
Revenues:				
Oil and gas sales	$ 39,246	$ 27,992	$ 73,262	$ 56,324
Sales from natural gas marketing activities	29,924	29,129	51,911	71,071
Oil and gas well drilling operations	1,739	3,745	5,769	9,023
Well operations and pipeline income	1,292	2,486	4,590	4,776
Oil and gas price risk management, net	3,742	1,370	(1,903)	6,295
Other	2	21	228	24
Total revenues	75,945	64,743	133,857	147,513
Costs and expenses:				
Oil and gas production and well operations cost	11,628	6,830	20,663	13,779
Cost of natural gas marketing activities	28,780	28,471	50,292	70,251
Cost of oil and gas well drilling operations	246	3,278	810	7,490
Exploration expense	6,780	1,898	9,458	3,106
General and administrative expense	6,886	5,102	14,310	8,821
Depreciation, depletion and amortization	17,429	7,605	30,503	14,192
Total costs and expenses	71,749	53,184	126,036	117,639
Gain on sale of leaseholds	25,600	-	25,600	-
Income from operations	29,796	11,559	33,421	29,874
Interest income	454	349	1,597	741
Interest expense	(1,450)	(436)	(2,281)	(788)
Income before income taxes	28,800	11,472	32,737	29,827
Income taxes	10,749	4,192	12,185	10,902
Net income	$ 18,051	$ 7,280	$ 20,552	$ 18,925
Earnings per common share:				
Basic	$ 1.22	$ 0.45	$ 1.40	$ 1.18
Diluted	$ 1.21	$ 0.45	$ 1.38	$ 1.17
Weighted average common shares outstanding:				
Basic	14,740	16,058	14,730	16,086
Diluted	14,860	16,134	14,851	16,164

**See Note 1.*

See accompanying notes to condensed consolidated financial statements.

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PETROLEUM DEVELOPMENT CORPORATION
Condensed Consolidated Statements of Cash Flows
(unaudited, in thousands)

	Six Months Ended June 30,	
	2007	2006 *Revised**
Cash flows from operating activities:		
Net income	$ 20,552	$ 18,925
Adjustments to net income to reconcile to cash used in operating activities:		
Deferred income taxes	5,707	1,619
Depreciation, depletion and amortization	30,503	14,192
Accretion of asset retirement obligation	469	249
Exploratory dry hole costs	194	1,903
Gain from sale of assets	-	(12)
Gain from sale of leaseholds	(25,600)	-
Expired and abandoned leases	1,193	16
Stock-based compensation	1,024	666
Unrealized loss (gain) on derivative transactions	2,523	(4,562)
Changes in assets and liabilities related to operations:		
(Decrease) increase in current assets	(34,825)	10,006
Increase (decrease) in other assets	223	(7)
Decrease in current liabilities	(74,468)	(58,721)
(Decrease) increase in other liabilities	(3,880)	1,783
Net cash used in operating activities	(76,385)	(13,943)
Cash flows from investing activities:		
Capital expenditures	(73,122)	(57,041)
Acquisitions	(201,594)	-
Decrease in restricted cash for property acquisition	191,155	-
Proceeds from sale of assets	-	14
Proceeds from sale of leases to partnerships	385	782
Net cash used in investing activities	(83,176)	(56,245)
Cash flows from financing activities:		
Proceeds from debt	162,000	136,000
Repayment of debt	(175,000)	(91,000)
Payment of debt issuance costs	-	(22)
Proceeds from exercise of stock options	164	31
Purchase of treasury stock	(343)	(10,153)
Net cash (used in) provided by financing activities	(13,179)	34,856
Net decrease in cash and cash equivalents	(172,740)	(35,332)

Cash and cash equivalents, beginning of period		194,326		90,110
Cash and cash equivalents, end of period	$	21,586	$	54,778

**See Note 1.*

See accompanying notes to condensed consolidated financial statements.

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Petroleum Development Corporation
Notes to Condensed Consolidated Financial Statements
June 30, 2007
(unaudited)

1. GENERAL

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

The accompanying interim condensed consolidated financial statements include the accounts of PDC, its wholly owned subsidiaries and WWWV, LLC, an entity in which the Company has a controlling financial interest (see Note 6). All material intercompany accounts and transactions have been eliminated in consolidation. Minority interest in earnings and ownership has been recorded for the percentage of the LLC not owned by PDC for each of the applicable periods. The Company accounts for its investment in interests in oil and natural gas limited partnerships under the proportionate consolidation method. Accordingly, the Company's condensed consolidated financial statements include its pro rata share of assets, liabilities, revenues and expenses of the limited partnerships in which it participates. The Company's proportionate share of all significant transactions between the Company and the limited partnerships is eliminated.

The accompanying interim 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 have been condensed or omitted. In the opinion of management, the accompanying interim 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 periods presented. The interim results of operations for the six months ended June 30, 2007, 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 interim 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, 2006, as filed with the SEC on May 23, 2007 ("2006 Form 10-K").

Items Affecting Comparability

Reclassifications have been made to the income statement data presented for the three and six months ended June 30, 2006, to conform to the current year presentation and to correct the prior period presentation. These reclassifications had no impact on reported net earnings, earnings per share, shareholders’ equity or total net cash flows. Oil and gas price risk management gains of $1.4 million and $6.3 million for the three and six months ended June 30, 2006, respectively, have been reclassified from non-operating gains to a component of revenues. These reclassifications and all other reclassifications are reflected in the revised amounts for three and six months ended June 30, 2006.

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As described in Note 1 to the Consolidated Financial Statements of the Company's 2006 Form 10-K, during the fourth quarter of 2006, the Company adopted SEC Staff Accounting Bulletin ("SAB") No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*. In accordance with SAB No. 108, the Company adjusted its opening financial position for 2006 by the cumulative effect of immaterial prior period misstatements. In connection with the adoption of SAB No. 108, the Company determined that certain similar errors were included in its results of operations for each of the first three quarters of 2006. The Company revised the data presented in Note 19, Quarterly Financial Data, to the Consolidated Financial Statements of its 2006 Form 10-K and revised the prior year quarterly financial statements included herein to reflect the correction of those immaterial misstatements.

The following table presents the income statement for the three month and six month periods ended June 30, 2006, as previously presented in the Company’s Form 10-Q for the related period, adjusted to reflect reclassifications to conform to current presentation and to correct previous presentation, and as revised to reflect the correction of prior period immaterial misstatements.

	Three Months Ended June 30, 2006			Six Months Ended June 30, 2006		
	Previously Reported	Reclassified (1)	Revised (2)	Previously Reported	Reclassified (1)	Revised (2)
	(in thousands, except per share data)					
Revenues:						
Oil and gas sales	$ 27,267	$ 27,267	$ 27,992	$ 56,476	$ 56,475	$ 56,324
Sales from natural gas marketing activities	29,129	29,129	29,129	71,071	71,071	71,071
Oil and gas well drilling operations	3,745	3,745	3,745	9,023	9,023	9,023
Well operations and pipeline income	2,486	2,486	2,486	4,776	4,776	4,776
Oil and gas price risk management, net	-	1,367	1,370	-	5,802	6,295
Other	364	21	21	754	24	24
Total revenues	62,991	64,015	64,743	142,100	147,171	147,513
Costs and expenses:						
Oil and gas production and well operations cost	6,313	6,770	6,830	13,417	14,031	13,779
Cost of natural gas marketing activities	28,462	28,462	28,471	70,238	70,237	70,251
Cost of oil and gas well drilling operations	3,474	3,159	3,278	7,630	7,240	7,490

Exploration expense	1,657	1,657	1,898	2,795	2,820	3,106
General and administrative expense	4,667	4,667	5,102	8,647	8,648	8,821
Depreciation, depletion and amortization	7,617	7,617	7,605	14,233	14,233	14,192
Total costs and expenses	52,190	52,332	53,184	116,960	117,209	117,639
Income from operations	10,801	11,683	11,559	25,140	29,962	29,874
Interest income	-	343	349	-	731	741
Interest expense	(267)	(125)	(436)	(447)	(198)	(788)
Oil and gas price risk management, net	1,367	-	-	5,802	-	-
Income before income taxes	11,901	11,901	11,472	30,495	30,495	29,827
Income taxes	4,351	4,351	4,192	11,147	11,147	10,902
Net income	$ 7,550	$ 7,550	$ 7,280	$ 19,348	$ 19,348	$ 18,925
Basic earnings per common share	$ 0.47	$ 0.47	$ 0.45	$ 1.20	$ 1.20	$ 1.18
Diluted earnings per share	$ 0.47	$ 0.47	$ 0.45	$ 1.20	$ 1.20	$ 1.17

(1) *As previously reported in the corresponding Form 10-Q, reclassified to conform to current year presentation and to correct previous presentation.*

(2) *Reflects the impact of certain immaterial errors on the results previously reported in 2006.*

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The reclassifications and revisions discussed above have no impact on the condensed consolidated balance sheets presented herein, nor do they result in changes to the net decrease in cash and cash equivalents previously presented in the Form 10-Q for the six months ended June 30, 2006. However, certain line items within cash flows from operating activities and one line item within cash flow from investing activities for the six months ended June 30, 2006, have been adjusted herein to reflect the impact of the income statement revisions. Revised line items are as follows:

	Six Months Ended June 30, 2006	
	Previously Reported	Revised [1]
Certain statement of cash flow line items:	*(in thousands)*	
Net income	$ 19,348	$ 18,925
Deferred income taxes	1,671	1,619
Depreciation, depletion and amortization	14,233	14,192
Exploratory dry hole cost	1,617	1,903
Unrealized gain on derivative transactions	(4,096)	(4,562)
Decrease in current assets	9,645	10,006
Decrease in other current liabilities	(58,067)	(58,721)
Increase in other liabilities	1,649	1,783
Net cash used in operating activities	(13,088)	(13,943)
Capital expenditures	(57,896)	(57,041)
Net cash used in investing activities	(57,100)	(56,245)
Net decrease in cash and cash equivalents	(35,332)	(35,332)

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(1) *Reflects the impact of certain immaterial errors on the results previously reported in 2006.*

2. RECENT ACCOUNTING STANDARDS

Recently Adopted Accounting Standards

In June 2006, the Financial Accounting Standards Board ("FASB") issued Emerging Issues Task Force ("EITF") No. 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (That Is, Gross versus Net Presentation)*. EITF 06-3 addresses the income statement presentation of any tax collected from customers and remitted to a government authority and concludes that the presentation of taxes on either a gross basis or a net basis is an accounting policy decision that should be disclosed pursuant to Accounting Principles Board ("APB") No. 22, *Disclosures of Accounting Policies*. For taxes that are reported on a gross basis (included in revenues and costs), EITF 06-3 requires disclosure of the amounts of those taxes in interim and annual financial statements, if those amounts are significant. EITF 06-3 became effective for interim and annual reporting periods beginning after December 15, 2006. The adoption of the standard, effective January 1, 2007, did not have a significant impact on the accompanying condensed consolidated financial statements. The Company's existing accounting policy, which was not changed upon the adoption of EITF 06-3, is to present taxes within the scope of EITF 06-3 on a net basis.

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 No. 48 provides that the tax effects from an uncertain tax position can be recognized in the financial statements, only if the position is more likely than not of being sustained on audit by the Internal Revenue Service ("IRS"), based on the technical merits of the position. The provisions of FIN No. 48 became effective for the Company on January 1, 2007. The cumulative effect of applying the provisions of FIN No. 48 has been accounted for as an adjustment to retained earnings in the first quarter of 2007. The adoption of FIN No. 48 resulted in a $0.3 million cumulative effect adjustment (see Note 5 for further discussion).

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In May 2007, the FASB issued FASB Staff Position FIN No. 48-1, *Definition of Settlement in FASB Interpretation No. 48* ("FIN No. 48-1"). FIN No. 48-1 amends FIN No. 48 to provide guidance on how an entity should determine whether a tax position is effectively settled for the purpose of recognizing previously unrecognized tax benefits. The term "effectively settled" replaces the term "ultimately settled" when used to describe recognition, and the terms "settlement" or "settled" replace the terms "ultimate settlement" or "ultimately settled" when used to describe measurement of a tax position under FIN No. 48. FIN No. 48-1 clarifies that a tax position can be effectively settled upon the completion of an examination by a taxing authority without being legally extinguished. For tax positions considered effectively settled, an entity would recognize the full amount of tax benefit, even if the tax position is not considered more likely than not to be sustained based solely on the basis of its technical merits and the statute of limitations remains open. The adoption of FIN No. 48-1, effective January 1, 2007, did not have an impact on the accompanying condensed consolidated financial statements.

Recently Issued Accounting Standards

In September 2006, the FASB issued Statement of Financial Accounting Standards ("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 and expands required disclosure about fair value measurements. SFAS No. 157 does not expand the use of fair value in any new circumstances. The provisions of SFAS No. 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Company is evaluating the impact that this new standard will have, if any, on its consolidated financial statements when adopted in 2008.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. SFAS No. 159 permits entities to choose to measure, at fair value, many financial instruments and certain other items that are not currently required to be measured at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. The statement will be effective as of the beginning of an entity's first fiscal year beginning after November 15, 2007. The Company is evaluating the impact of adopting SFAS No. 159 in its consolidated financial statements when it is adopted in 2008.

In April 2007, the FASB issued FSP FIN No. 39-1, *Amendment of FASB Interpretation No. 39* ("FIN No. 39-1"), to amend certain portions of Interpretation 39. FIN No. 39-1 replaces the terms "conditional contracts" and "exchange contracts" in Interpretation 39 with the term "derivative instruments" as defined in Statement 133. FIN No. 39-1 also amends Interpretation 39 to allow for the offsetting of fair value amounts for the right to reclaim cash collateral or receivable, or the obligation to return cash collateral or payable, arising from the same master netting arrangement as the derivative instruments. FIN No. 39-1 applies to fiscal years beginning after November 15, 2007, with early adoption permitted. The Company is currently in the process of evaluating the impact that FIN No. 39-1 will have, if any, on its consolidated financial statements when adopted in 2008.

3. ACQUISITIONS

Acquisition of Internal Revenue Code Section 1031 – Like-Kind Exchange Properties

During the first quarter of 2007, the Company completed its acquisitions of suitable like-kind properties in accordance with the like-kind exchange ("LKE") agreement it entered into in connection with its sale of undeveloped leaseholds located in Grand Valley Field, Garfield County, Colorado in July 2006. The Company acquired for cash qualifying oil and gas properties totaling $188.9 million, including costs of acquisition, as described below.

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EXCO Properties. On January 5, 2007, the Company completed its purchase of producing properties and undeveloped drilling locations and acreage in the Wattenberg Field area of the DJ Basin, Colorado from EXCO Resources Inc., an unaffiliated party. The acquisition included substantially all of EXCO's assets in the area and encompassed 144 oil and natural gas wells (approximating 25.5 Bcfe proved developed reserves as of December 31, 2005) and 8,160 acres of leasehold. The wells and leases acquired are located in Weld, Adams, Larimer, and Broomfield Counties, Colorado. The Company operates the assets and holds a majority working interest in the properties.

Company-Sponsored Partnerships. On January 10, 2007, the Company completed the purchase of the remaining working interests in 44 Company-sponsored partnerships. The transaction resulted in an increase in the Company's ownership in 718 gross wells (423 net wells) that are currently operated by the Company. The wells are located primarily in the Appalachian Basin and Michigan.

The following table presents the adjusted preliminary purchase price for each of the acquisitions described above as of June 30, 2007.

		EXCO		Partnerships
		(in thousands)		
Cash consideration paid	$	128,672	$	57,776
Plus: direct costs of acquisition		1,662		1,664
Less: acquisition cost adjustments		(119)		(2,792)
Total preliminary acquisition cost	$	130,215	$	56,648

The following table presents, as of the respective date of acquisition, the preliminary allocations of the purchase prices based on estimates of fair value.

		EXCO		Partnerships
		(in thousands)		
Current assets acquired	$	91	$	-
Proved oil and gas properties		117,425		46,870
Unproved oil and gas properties		14,960		13,273
Asset retirement obligation		(748)		(3,495)
Other liabilities assumed		(1,513)		-
Preliminary acquisition cost	$	130,215	$	56,648

The assessment of fair value of proved oil and gas properties acquired was based primarily on projections of expected discounted future cash flows of acquired oil and natural gas reserves. To compensate for the inherent risk of estimating and valuing unproved properties, the discounted future net revenues of probable reserves were reduced by additional risk-weighting factors in that valuation. The purchase price allocations are preliminary, subject to fair value appraisals and evaluations of the assets acquired. The amounts are subject to change as additional information becomes available and is assessed by the Company.

Other. In January 2007, the Company acquired from unaffiliated parties other like-kind undeveloped leaseholds in Erath County, Texas for $2.1 million, including costs of acquisition. Acreage in this area is prospective for development of oil and natural gas reserves in the Barnett Shale.

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Other Acquisitions

Unioil. On December 6, 2006, the Company completed a cash tender offer and purchased approximately 95.5% or 9,112,750 shares of the outstanding common stock of Unioil, an independent energy company with properties in northern Colorado and southern Wyoming. The acquisition of more than 90% of the outstanding shares of common stock allowed the Company to effect a short-form merger of Unioil and a wholly owned subsidiary of the Company, resulting in the acquisition of the remaining 428,719 shares of Unioil. Each share of Unioil common stock not tendered through the offer was converted into the right to receive $1.91 in cash, the same consideration paid for shares in the tender offer. The Company paid $18.6 million, including $0.4 million of direct acquisition costs, for 100% of Unioil's outstanding common stock.

The assessment of the fair values of oil and gas properties acquired was based primarily on projections of expected future net cash flows, discounted to present value. The preliminary allocation of acquisition cost included $6.8 million in goodwill, which was re-allocated to properties and equipment in the first quarter of 2007 as part of the Company's ongoing process of finalizing the preliminary allocation of the purchase price. As a result of this reclassification, the deferred tax liabilities increased and thus increased property and equipment. This increase was approximately $4.2 million. The purchase price allocation is preliminary, subject to completing the evaluation of proved and unproved oil and gas properties. These amounts are subject to change as additional information becomes available and is assessed by the Company.

Other. On February 22, 2007, the Company acquired, from an unaffiliated party, 28 producing wells and associated undeveloped acreage located in Colorado (Wattenberg Field) for a purchase price of $12 million, which was allocated to oil and gas properties.

Pro Forma Financial Information

The results of operations for all of the above acquisitions have been included in the condensed consolidated financial statements from the date of acquisition. The pro forma effect of the inclusion of the results of operations for all of the above acquisitions, individually and in the aggregate, in the Company's condensed consolidated statement of income for the six months ended June 30, 2007, was not material.

The following unaudited pro forma financial information presents a summary of the Company's consolidated results of operations for the three and six months ended June 30, 2006, assuming the acquisitions of the EXCO properties and Company-sponsored partnerships had been completed as of January 1, 2006, including adjustments to reflect the allocation of the purchase price to the acquired net assets. The pro forma effect of the inclusion of the results of operations for all of the other acquisitions described above, individually and in the aggregate, was not material.

	June 30, 2006			
	Three Months Ended		Six Months Ended	
	(in thousands, except per share data)			
Total revenues	$	70,913	$	161,620
Net income		8,334		22,366
Earnings per common share:				
Basic	$	0.52	$	1.39
Diluted	$	0.52	$	1.38

The pro forma results of operations are not necessarily indicative of what the Company's results of operations would have been had the EXCO properties and Company-sponsored partnerships been acquired at the beginning of the period indicated, nor does it purport to represent results of operations for any future periods.

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4. 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 LKE agreement. As of December 31, 2006, $300 million remained in the trust, with $109 million reflected in cash and cash equivalents as a current asset in the condensed consolidated balance sheet and the remaining $191.5 million reflected as restricted cash - long term. The $191.5 million represents the amounts paid in January 2007 for the acquisition of oil and gas properties qualifying for LKE treatment which are included in oil and gas properties at June 30, 2007.

In June 2007, the Company funded an escrow account in the amount of $14.1 million for amounts due to the limited partners of the Company sponsored drilling partnership as a result of the Company over withholding estimated production taxes in years prior to 2007 and is included in restricted cash, current, in the condensed consolidated balance sheet as of June 30, 2007.

5. INCOME TAXES

Effective January 1, 2007, the Company adopted FIN No. 48, which clarifies the accounting for uncertainty in income taxes recognized in an entity's financial statements in accordance with FASB Statement 109, *Accounting for Income Taxes*, by prescribing the minimum recognition threshold and measurement attribute a tax position taken or expected to be taken on a tax return is required to meet before being recognized in the financial statements. The Company recorded a $0.3 million reduction in retained earnings at January 1, 2007, to recognize the cumulative effect of the adoption of FIN No. 48. This amount represents the total amount of interest on unrecognized tax benefits as of the date of adoption. As of January 1, 2007, unrecognized tax benefits amounted to $1 million and are included in federal and state income taxes payable in the condensed consolidated balance sheet. None of the unrecognized tax benefits relate to a position that, if recognized, will impact the Company's effective tax rate. Due to the variable nature of the income or expense to which the uncertain tax position relates, the Company, as of June 30, 2007, is unable to predict whether the unrecognized tax benefit will significantly increase or decrease in the next twelve months.

The Company, as a matter of accounting policy, recognizes interest and penalties related to unrecognized tax benefits, if applicable, in income tax expense in the condensed consolidated statements of income. During the three and six months ended June 30, 2007, there was no material change to the amount of interest recorded on unrecognized tax benefits. Accruals for interest on unrecognized tax benefits totaled $0.3 million at June 30, 2007, which are included in federal and state income taxes payable in the condensed consolidated balance sheet. There were no accruals for penalties on unrecognized tax benefits at January 1, 2007, or during the three and six months ended June 30, 2007.

At June 30, 2007, the Company's federal income tax returns were closed through the 2002 tax year and there are no outstanding tax controversies with any taxing authorities regarding these prior tax years. Additionally, at June 30, 2007, the IRS was examining the Company's 2003 and 2004 tax years. Subsequently, the Company reached final settlement of this examination with the IRS and the examination was officially concluded and the revenue agent's report was signed on July 31, 2007. The impact of the settlement will be recorded in the third quarter and is currently not expected to have a material effect on the Company's effective tax rate.

State and other income tax returns are generally subject to examination for a period of three to five years after the filing of the respective returns. The state impact of any amended federal returns, whether or not pursuant to IRS examination changes or pursuant to Company voluntary changes, remains subject to examination by various states for a period of up to one year after formal notification of such amendments to the states. The Company currently has no state income tax returns in the process of examination or administrative appeal.

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The Company filed its 2004 state income tax returns in June 2007, which begins the statute of limitations for examination and adjustment. The Company is currently delinquent in its 2005 federal and state income tax filings and plans to file these returns by mid September 2007. Accordingly, the normal federal and state statute of limitations for the 2005 tax year will not begin until the return filing dates.

6. MINORITY INTEREST IN CONSOLIDATED LIMITED LIABILITY COMPANY

On May 8, 2007, the Company contributed $0.8 million for a 50% interest in WWWV, LLC ("LLC"), a limited liability company for which the Company serves as the managing member. One-sixth of the entity is owned by the Chief Executive Officer of the Company, who paid the same unit price for his interest as was paid by the Company and unrelated third parties for such interest in the LLC. The LLC's only asset is an aircraft and it was formed for the purpose of owning and operating the aircraft.

The minority interest portion of pre-tax expense incurred by and belonging to the minority interest holders of the consolidated limited liability company is not material.

7. EARNINGS PER SHARE

A reconciliation of basic and diluted earnings per common share is as follows:

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(in thousands, except per share data)			
Weighted average common shares outstanding	14,740	16,058	14,730	16,086
Dilutive effect of share-based compensation:				
Unamortized portion of restricted stock	69	13	65	13
Stock options	46	63	51	65
Non employee director deferred compensation	5	-	5	-
Weighted average common and common equivalent shares outstanding	14,860	16,134	14,851	16,164
Net income	$ 18,051	$ 7,280	$ 20,552	$ 18,925
Basic earnings per common share	$ 1.22	$ 0.45	$ 1.40	$ 1.18
Diluted earnings per common share	$ 1.21	$ 0.45	$ 1.38	$ 1.17

Options with an exercise price exceeding the average price of the underlying securities are not considered to be dilutive and are not included in the calculation of the denominator for diluted earnings per share. There were no anti-dilutive options for the three and six months ended June 30, 2007 or 2006.

8. STOCK-BASED COMPENSATION

The Company maintains a long-term equity compensation plan for directors, officers and certain key employees of the Company. In accordance with the plan, awards may be issued in the form of stock options, stock appreciation rights, restricted stock or performance shares.

The following table provides a summary of the impact of the Company's stock based compensation plans on its results of operations for the periods presented.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in thousands)			
Total share-based compensation expense	$ 541	$ 458	$ 1,024	$ 666
Income tax benefit	(202)	(167)	(381)	(243)
Net income impact	$ 339	$ 291	$ 643	$ 423

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Stock Option Awards. 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 Company did not grant any stock option awards for the six months ended June 30, 2007. The weighted average fair value per share of the options granted during the six months ended June 30, 2006, as computed using the Black-Scholes pricing model was $18.92. The weighted average assumptions used to estimate these fair values were as follows:

	Six Months Ended June 30, 2006
Expected Volatility	39.5%
Expected term (in years)	5.9
Risk-free interest rate	4.3%

Expected volatilities are 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 cash dividends, nor does it expect to declare cash dividends in the foreseeable future.

The following table provides a summary of the Company's stock option award activity for the six months ended June 30, 2007:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term *(in years)*	Aggregate Intrinsic Value *(in millions)*
Outstanding at December 31, 2006	89,567	$ 21.36	5.6	$ 2.0
Exercised	(33,000)	4.95	-	1.5
Outstanding at June 30, 2007	56,567	30.92	6.4	0.9
Vested and expected to vest at June 30, 2007	52,808	29.93	6.3	0.9
Exercisable at June 30, 2007	29,529	20.46	4.6	0.8

Total unrecognized stock-based compensation cost related to stock options, net of estimated forfeitures, was $0.4 million as of June 30, 2007. This cost is expected to be recognized over a weighted average period of 2.4 years.

Restricted and Performance Share Awards. During the six months ended June 30, 2007, the Company awarded 33,345 restricted shares with a weighted average grant date fair value of $50.96 per share and 31,972 performance vesting (market based) shares of restricted stock with a weighted average grant date fair value of $36.07 per share. The fair value of the restricted awards, excluding the market based performance shares, is amortized over the requisite service period, which for the Company is ratably over four years from the date of grant. The market based performance shares vest only upon the achievement of certain per share price thresholds and continuous employment during the vesting period. The weighted average grant date fair value of each performance share was computed using the Monte Carlo pricing model and the following weighted average assumptions:

Expected term of award	3 years
Risk-free interest rate	4.7%
Volatility	44.0%

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The following table provides a summary of the Company's restricted and performance share awards activity for the six months ended June 30, 2007:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2006	131,730	$ 39.87
Granted	65,317	43.67
Vested	(27,176)	38.15
Forfeited	(1,392)	40.29
Non-vested at June 30, 2007	168,479	41.62

The total compensation cost related to non-vested and expected to vest awards not yet recognized as of June 30, 2007, was $4.9 million. The cost is expected to be recognized over a weighted-average period of 3.1 years.

9. PROPERTIES AND EQUIPMENT

	June 30, 2007	December 31, 2006
	(in thousands)	
Properties and equipment, net:		
Oil and gas properties (successful efforts method of accounting)	$ 822,734	$ 500,506
Pipelines and related facilities [1]	18,377	12,673
Transportation and other equipment [2]	17,146	7,870
Land and buildings	11,862	11,620
Construction in progress [3]	2,166	4,801
	872,285	537,470
Less accumulated depreciation, depletion and amortization	173,760	143,253
	$ 698,525	$ 394,217

[1] *At June 30, 2007, includes $2.7 million related to additional compressors and upgraded pipeline facilities in the Company's Piceance Basin production operations, which was placed in service in June 2007.*

[2] *At June 30, 2007, includes $5.1 million related to the Garden Gulch road, which was placed in service in May 2007. At December 31, 2006, construction in progress included $3.6 million related to the Garden Gulch road.*

[3] *At June 30, 2007, includes costs primarily related to a new integrated oil and gas accounting software system.*

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Suspended Well Costs.

The following table identifies the capitalized exploratory well costs that are pending determination of proved reserves and are included in oil and gas properties in the accompanying condensed consolidated balance sheets in accordance with FASB Staff Position No. 19-1, *Accounting for Suspended Well Costs*.

	Amount *(in thousands)*	Number of Wells
Beginning balance at December 31, 2006	$ 765	1
Additions to capitalized exploratory well costs pending the determination of proved reserves	1,992	3
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(879)	(1)
Capitalized exploratory well costs charged to expense	(765)	(1)
Ending balance at June 30, 2007	$ 1,113	2

As of June 30, 2007, neither of the two wells awaiting the determination of proved reserves has been capitalized for a period greater than one year.

10. ASSET RETIREMENT OBLIGATION

Changes in carrying amounts of the asset retirement obligations associated with the Company's working interest in oil and gas properties are as follows:

	Amount *(in thousands)*
Beginning balance at December 31, 2006	$ 11,966
Obligations assumed with development activities and acquisitions	5,096
Accretion expense	469
Obligations discharged with disposed properties and asset retirements	(22)
Ending balance at June 30, 2007	$ 17,509

Approximately $50,000 of the $17.5 million asset retirement obligation is classified as short term and included in other accrued expenses as of December 31, 2006, and June 30, 2007.

11. LONG-TERM DEBT

The Company has a credit facility with JPMorgan Chase Bank, N.A. ("JPMorgan") and BNP Paribas of $200 million subject to and collateralized by required levels of oil and natural gas reserves. Effective May 25, 2007, the Company's current borrowing base, based upon current oil and natural gas reserves, was increased from $100 million to $135 million, which was fully activated at that time. The Company is required to pay a commitment fee of 0.25% to 0.375% per annum on the unused portion of the activated credit facility. Interest accrues at an alternative base rate ("ABR") or adjusted LIBOR at the discretion of the Company. The ABR is the greater of JPMorgan's prime rate, an adjusted secondary market rate for a three-month certificate of deposit plus 1% or the federal funds effective rate plus 0.5%. ABR borrowings are assessed an additional margin spread up to 0.375% and adjusted LIBOR borrowings are assessed an additional margin spread of 1.125% to 1.875%. The margin spread charges are based upon the outstanding balance under the credit facility. No principal payments are required until the credit agreement expires on November 4, 2010.

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On December 19, 2006, the Company executed, pursuant to its credit facility, an overline note in the amount of $20 million to be repaid on January 31, 2007. Interest on the overline note accrued at a per annum rate equal to the alternate base rate plus 0.80% until December 22, 2006, at which time the rate converted to a Eurodollar borrowing for a one month period and at a per annum rate equal to an adjusted LIBOR rate plus 2.30%. The overline note was paid in full in accordance with its terms in January 2007.

As of June 30, 2007, the outstanding balance under the credit facility was $124 million compared to $117 million, excluding the overline note discussed above, as of December 31, 2006. Any amounts outstanding under the credit facility are collateralized by substantially all of the Company's properties. At June 30, 2007, the outstanding balance was subject to an ABR of 8.625%. The credit agreement requires, among other things, the existence of satisfactory levels of oil and natural gas reserves and the maintenance of certain working capital and tangible net worth ratios. At June 30, 2007, the Company was not in compliance with its current ratio covenant. Effective July 5, 2007, the Company increased its borrowing base by $15 million to $150 million, and effective August 9, 2007, the Company amended its credit facility adding a new bank, Wachovia Bank, N.A. and increasing its aggregate commitments from $150 million to $200 million. The amendment also waives the working capital covenant until the earlier of (i) a debt or equity transaction resulting in net proceeds to the Company of at least $200 million or (ii) July 1, 2008. Under the amended agreement the ABR rate was increased by 0.375% as long as the waiver of the Company's non-compliance with the working capital covenant is in effect. The Company believes that after this amendment the Company will be able to sustain compliance with all covenants.

12. SUPPLEMENTAL CASH FLOW DISCLOSURE

	Six Months Ended June 30,	
	2007	2006
	(in thousands)	
Cash paid for:		
Interest	$ 3,915	$ 608
Income taxes	42,447	18,335
Non-cash investing activities:		
Change in deferred tax liability resulting from reallocation of acquisition purchase price	4,188	-
Changes in accounts payable - affiliates related to acquisition of partnerships	668	-
Changes in accounts payable related to purchases of property and equipment	27,335	2,456

13. COMMITMENTS AND CONTINGENCIES

The Company would be exposed to oil and 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 natural gas marketing contracts not perform. Nonperformance is not anticipated. There were no counterparty default losses in 2006 or through the second quarter of 2007.

In connection with the Company's sale of undeveloped leaseholds in July 2006, the Company, pursuant to the purchase and sale agreement, was obligated to either drill 16 wells on specifically identified acreage over the next three years or pay liquidated damages of $1.6 million per undrilled well for a total contingent obligation of $25.6 million, which was reflected as a deferred gain on sale of leaseholds in the accompanying condensed consolidated balance sheet at December 31, 2006. On May 31, 2007, the Company entered into a letter agreement amending the original purchase and sale agreement. The letter agreement relieved the Company of its obligation, in its entirety, to either drill 16 wells or pay liquidated damages, resulting in the recognition of the remaining $25.6 million deferred gain on sale of leaseholds in the quarter ended June 30, 2007.

Pursuant to the above letter agreement, the Company is obligated to drill six wells on specifically identified acreage. These wells will be drilled on the unaffiliated party's leasehold for its benefit and at its cost. In addition, the unaffiliated party will return 160 acres of leasehold property acquired from the Company pursuant to the purchase and sale agreement. The Company is currently drilling the first of the six wells.

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The Company was party to an exploration agreement with an unaffiliated party. The agreement required the Company to drill a minimum of 25 exploratory wells through June 30, 2007. For each well the Company failed to drill prior to June 30, 2007, the Company was required to pay liquidated damages equal to $125,000 per undrilled well. After drilling three exploratory wells, the Company determined, based on drilling results, not to drill the remaining 22 exploratory wells. During the quarter ended June 30, 2007, the Company recorded charges to exploration expense for the liquidated damages of $2.8 million related to the 22 undrilled wells and $1.1 million related to the write-off of the carrying value of the acreage resulting from the abandonment of the project. With regard to the liquidated damages and while the Company acknowledges its liability, the Company is currently negotiating an alternative settlement of this liability. However, there can be no assurance that an alternative settlement will be reached.

The Company is currently offering its 2007 drilling partnership, Rockies Region 2007 Limited Partnership, and, as of August 7, 2007, has received subscriptions of $53 million, with a maximum amount of subscriptions of $110 million to be funded. The Company expects the partnership to be funded and drilling for the new program is scheduled to commence in the third quarter of 2007, with drilling and completion operations continuing through the first and second quarters of 2008. No assurance can be made that the Company will continue to receive this level of funding from this or future programs. 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. The Company expects to fund its equity contribution in the third quarter of 2007.

Substantially all of the Company's drilling programs contain a repurchase provision where investing partners may request that the Company purchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), if repurchase is requested by investors, and subject to the Company's financial ability to do so. The maximum annual potential repurchase obligation as of June 30, 2007, was approximately $6.1 million. The Company has adequate liquidity to meet this potential obligation. During 2006 and the first six months of 2007, the Company paid $0.8 million and $0.7 million, respectively, under this provision for the repurchase of partnership units.

As managing general partner of 32 partnerships, the Company has liability 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 two drilling rigs, the Company made commitments to the drilling contractor, which call for a minimum commitment of $9,000 daily for a specified amount of time if the Company does not use the drilling rigs, an event that is not anticipated to occur, and a maximum commitment of $38,800 daily for a specified amount of time for daily use of the drilling rigs. Commitments for these two separate contracts expire in July 2009 and May 2010. As of June 30, 2007, the Company has an outstanding minimum commitment for $8.1 million and an outstanding maximum commitment for $35.3 million.

14. LEGAL PROCEEDINGS

From time to time, the Company is a party to various legal proceedings in the ordinary course of business. While it is not possible to determine with any degree of certainty the ultimate outcome of the following legal proceeding, the Company believes that it has meritorious defenses with respect to the claims asserted against it and intends to vigorously defend its position. An adverse outcome in the case below or any similar case could have a material adverse effect, individually and collectively, on the Company’s financial position, liquidity and results of operations.

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Royalty Payments. On May 29, 2007, Glen Droegemueller, individually and as representative plaintiff on behalf of all others similarly situated, filed a class action complaint against the Company in the District Court, Weld County, Colorado alleging that the Company underpaid royalties on natural gas produced from wells operated by the Company in the State of Colorado (the "Droegemueller Action"). The plaintiff seeks declaratory relief and to recover an unspecified amount of compensation for underpayment of royalties made by the Company to the plaintiff pursuant to leases. The Company moved the case to Federal Court on June 28, 2007, and on July 10, 2007, the Company filed its answer and affirmative defenses. Given the preliminary stage of this proceeding and the inherent uncertainty in litigation, the Company is unable to predict the ultimate outcome of this suit at this time.

Litigation similar to the Droegemueller Action has recently been commenced against several other companies in other jurisdictions where the Company conducts business. While the Company's business model differs from that of the parties involved in such other litigation, and although the Company has not been named as a party in such other litigation, there can be no assurance that the Company will not be named as a party to such other litigation in the future.

Other. The Company is involved in various other legal proceedings that it considers normal to its business. The Company believes that the ultimate outcome of such other proceedings will not have a material adverse effect on its financial position, liquidity or results of operations.

15. BUSINESS SEGMENTS

The Company's operating activities are divided into four major segments: oil and gas sales, natural gas marketing, drilling and development, and well operations and pipeline income. The Company owns an interest in approximately 3,400 wells from which it sells its oil and natural gas production from its working interests in the wells. Included in the oil and gas sales segment are the operating results of the acquisitions described in Note 3. A wholly-owned subsidiary, Riley Natural Gas ("RNG"), engages in the marketing of natural gas to commercial and industrial end-users. The Company drills natural gas wells for Company-sponsored drilling partnerships and retains an interest in each well. The Company charges Company-sponsored partnerships and other third parties competitive industry rates for well operations and natural gas gathering. All material inter-company accounts and transactions between segments have been eliminated.

Segment information for the three and six months ended June 30, 2007 and 2006, is presented below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006 **Revised*	2007	2006 **Revised*
		(in thousands)		
Revenues:				
Oil and gas sales (1)	$ 42,988	$ 29,362	$ 71,359	$ 62,619
Natural gas marketing	29,924	29,129	51,911	71,071
Drilling and development	1,739	3,745	5,769	9,023
Well operations and pipeline income	1,292	2,486	4,590	4,776
Unallocated amounts	2	21	228	24
Total	$ 75,945	$ 64,743	$ 133,857	$ 147,513
Segment income (loss) before income taxes:				
Oil and gas sales (2)	$ 8,521	$ 14,997	$ 14,360	$ 35,474
Natural gas marketing	1,345	800	2,024	1,124

Drilling and development	1,493	467	4,959	1,534
Well operations and pipeline income	179	612	1,414	1,031
Unallocated amounts [3]	17,262	(5,404)	9,980	(9,336)
Total	$ 28,800	$ 11,472	$ 32,737	$ 29,827

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	June 30, 2007	December 31, 2006
	(in thousands)	
Segment assets:		
Oil and gas sales	$ 647,816	$ 394,952
Natural gas marketing	33,296	39,899
Drilling and development [(4)]	53,188	87,746
Well operations and pipeline income	38,712	28,895
Unallocated amounts [(5)]	63,671	332,795
Total	$ 836,683	$ 884,287

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** See Note 1.*

(1) Includes oil and gas price risk management, net.

(2) Includes $9.5 million and $3.1 million in exploration expense and $28.9 million and $13.2 million of DD&A for the six months ended June 30, 2007 and 2006, respectively.

(3) Includes general and administrative expense, interest income, interest expense, and DD&A expense of $0.4 million and $0.1 million for the six months ended June 30, 2007 and 2006, respectively. The three and six months ended June 30, 2007, includes $25.6 million related to the gain on sale of leasehold.

(4) The December 31, 2006, amount includes cash of $50.7 million for partnership drilling activities, which was substantially utilized by June 30, 2007.

(5) Includes primarily unallocated cash. The December 31, 2006, amount includes designated cash of $191.5 million, which was utilized in LKE property transactions during the first quarter of 2007 and included in the oil and gas sales segment as of June 30, 2007.

16. DERIVATIVE FINANCIAL INSTRUMENTS

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. Company policy prohibits the use of oil and natural gas future and option contracts for speculative purposes. These instruments consist of New York Mercantile Exchange ("NYMEX") traded natural gas futures contracts and option contracts for Appalachian and Michigan production, Panhandle-based contracts and NYMEX-traded contracts for Northeast Colorado ("NECO") production and Colorado Interstate Gas Index ("CIG") based contracts for other Colorado production. The Company purchases puts and participating collars for its own and affiliate partnerships production to protect against possible price instability in future periods while retaining much of the benefits of price increases. RNG enters into fixed-price physical purchase and sale agreements that are derivative contracts. In order to offset these fixed-price physical derivatives, the Company enters into financial derivative instruments that have the effect of locking in the prices the Company will recieve or pay for the same volumes and period, offsetting the physical derivative. 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 recived from price changes in the physical market.

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The following tables summarize the open derivative option and purchase and sales contracts for PDC and RNG as of June 30, 2007.

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

Commodity	Type	Quantity Gas-MMbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Value
Total Positions as of June 30, 2007					
Natural Gas	Cash Settled Option Sales	16,780,000	$ 10.69	$ 179,387	$ (4,874)
Natural Gas	Cash Settled Option Purchases	26,920,000	5.56	149,598	14,760
Oil	Cash Settled Option Purchases	120,000	50.00	6,000	(3)
Positions maturing in 12 months following June 30, 2007					
Natural Gas	Cash Settled Option Sales	9,900,000	$ 10.70	$ 105,927	$ (2,608)
Natural Gas	Cash Settled Option Purchases	20,040,000	5.48	109,878	10,940
Oil	Cash Settled Option Purchases	120,000	50.00	6,000	(3)

The maximum term for the derivative contracts listed above is 16 months.

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

Commodity	Type	Quantity Gas-MMbtu	Weighted Average Price	Total Contract Amount	Fair Value
Total Positions as of June 30, 2007					
Natural Gas	Cash Settled Futures/Swaps Purchases	252,200	$ 7.30	$ 1,840	$ (107)
Natural Gas	Cash Settled Futures/Swaps	2,278,600	8.52	19,412	1,702

	Sales				
Natural Gas	Cash Settled Option Purchases	120,000	5.50	660	10
Natural Gas	Cash Settled Option Sales	60,000	10.10	606	(13)
Natural Gas	Physical Purchases	2,278,600	8.51	19,396	(878)
Natural Gas	Physical Sales	132,220	9.43	1,247	148
Positions maturing in 12 months following June 30, 2007					
Natural Gas	Cash Settled Futures/Swaps Purchases	252,200	$ 7.30	$ 1,840	$ (107)
Natural Gas	Cash Settled Futures/Swaps Sales	1,933,600	8.50	16,439	1,687
Natural Gas	Cash Settled Option Purchases	120,000	5.50	660	10
Natural Gas	Cash Settled Option Sales	60,000	10.10	606	(13)
Natural Gas	Physical Purchases	1,933,600	8.49	16,407	(960)
Natural Gas	Physical Sales	132,220	9.43	1,247	147

The maximum term for the derivative contracts listed above is 19 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 net payable to the partnerships of $4.6 million as of June 30, 2007, and $7.5 million as of December 31, 2006.

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The Company is required to maintain margin deposits with brokers for outstanding futures contracts. As of June 30, 2007, and December 31, 2006, restricted cash - current in the amount of $0.8 million and $0.5 million was on deposit.

By using derivative financial instruments to manage exposures to changes in interest rates and commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates repayment risk. The Company minimizes the credit or repayment risk in derivative instruments by entering into transactions with high-quality counterparties. There were no counterparty defaults in 2006 or during the six months ended June 30, 2007.

The following table identifies the fair value of commodity based derivatives as classified in the condensed consolidated balance sheets.

	June 30, 2007	December 31, 2006
	(in thousands)	
Classification in the Condensed Consolidated Balance Sheets:		
Fair value of derivatives - current asset	$ 12,785	$ 15,012
Other assets - long-term asset	3,925	1,146
	16,710	16,158
Fair value of derivatives - current liability	3,692	2,545
Other liabilities - long-term liability	2,273	-
	5,965	2,545
Net fair value of commodity based derivatives	$ 10,745	$ 13,613

The following tables identify the changes in the fair value of commodity based derivatives as reflected in the condensed consolidated statements of income.

	Three Months Ended June 30,			
	2007		2006	
Statement of income line item	Realized	Unrealized	Realized	Unrealized
	(in thousands, gains/(losses))			
Oil and gas price risk management, net	$ 27	$ 3,715	$ 48	$ 1,322 (1)
Sales from natural gas marketing activities	231	2,030	675	10,613
Cost of natural gas marketing activities	(49)	(1,631)	(418)	(10,869)

	Six Months Ended June 30,			
	2007		2006	
Statement of income line item	Realized	Unrealized	Realized	Unrealized
	(in thousands, gains/(losses))			
	$ 608	$ (2,511)	$ 1,450	$ 4,845 (1)

Oil and gas price risk management, net				
Sales from natural gas marketing activities	1,327	(1,268)	784	19,263
Cost of natural gas marketing activities	(223)	1,256	(1,046)	(20,140)

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(1) *Revised, see Note 1.*

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

The following discussion and analysis, as well as other sections in this Form 10-Q, should be read in conjunction with the condensed consolidated financial statements and related notes to condensed consolidated financial statements included elsewhere in this report.

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, 2006, and the Company’s other SEC filings and public disclosures. The Company undertakes no duty to update or revise these forward-looking statements.

Non-GAAP Financial Measure

The following management's discussion and analysis refers to "adjusted cash flow from operations," a non-GAAP financial measure. Adjusted cash flow from operations is the cash flow earned or incurred from operating activities without regard to the collection or payment of associated receivables or payables. The Company believes it is important to consider adjusted cash flow from operations separately, as the Company believes it can often be a better way to present, discuss and analyze changes in operating trends in its business caused by changes in production, prices, operating costs, and related operational factors, without regard to whether the earned or incurred item was collected or paid during that year. The Company also uses this measure because the collection of its receivables or payment of its obligations has not been a significant issue for the Company's business, but merely a timing issue from one period to the next, with fluctuations generally caused by significant changes in commodity prices. Adjusted cash flow from operations is not a measure of financial performance under GAAP and it should be considered in addition to, not as a substitute for, cash flows from operations, investing, or financing activities, nor as a liquidity measure or indicator of cash flows reported in accordance with U.S. GAAP.

Management Overview

Net income for the three and six months ended June 30, 2007, increased 148% and 8.6%, respectively, compared to the corresponding prior year periods. The increase was largely due to a $25.6 million non-cash pretax gain associated with the May 2007 resolution of certain drilling commitments related to its 2006 sale of a leasehold to an unrelated party (see Gain on Sale of Leaseholds).

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The following table presents the Company's net income and diluted earnings per share for the three and six months ended June 30, 2007 and 2006.

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Change Amount	Change Percent
	(dollars in thousands, except per share data)			
Net income	$ 18,051	$ 7,280	$ 10,771	148.0%
Diluted earnings per share	$ 1.21	$ 0.45	$ 0.76	168.9%

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006	Change Amount	Change Percent
	(dollars in thousands, except per share data)			
Net income	$ 20,552	$ 18,925	$ 1,627	8.6%
Diluted earnings per share	$ 1.38	$ 1.17	$ 0.21	17.9%

Total quarterly revenues were up 17.3%, in spite of a 9.1% decline in realized oil and natural gas prices, primarily due to a 54.3% increase in production. Revenues for the first half of the year were down 9.3%, in spite of a 49.9% increase in production, primarily due to a 13.4% decline in realized oil and natural gas prices. While commodity prices were down and expenses were up, as explained below, for the three and six-month periods, adjusted cash flow from operations was $16.8 million and $36.6 million, up 10.3% and 10.8%, respectively, from the prior year periods.

The following table presents the Company's reconciliation of adjusted cash flow from operations for the three and six months ended June 30, 2007 and 2006.

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(in thousands)			
Net cash used in operating activities	$ (43,647)	$ (16,698)	$ (76,385)	$ (13,943)
Changes in assets and liabilities related to operations	60,418	31,905	112,950	46,939
Adjusted cash flow from operations	$ 16,771	$ 15,207	$ 36,565	$ 32,996

Total expenses were up 34.9% and 7.1% for the three and six months ended June 30, 2007, compared to the same prior year periods, in large part due to the increased production. As explained in results of operations, depreciation, depletion and amortization expense, a non-cash expense, increased $9.8 million and $16.3 million, for the three and six months ended June 30, 2007, respectively, compared to the same prior year periods. The increases were largely due to three factors: increased production levels, the substantial acquisitions of proved mineral interests, and additions to wells and related equipment and facilities. Other significant changes in expense components are explained hereafter.

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Results of Operations

Three Months Ended June 30, 2007, Compared to Three Months Ended June 30, 2006

Revenues

The Company's revenues for the three months ended June 30, 2007 and 2006, are presented below.

	Three Months Ended June 30,		Change	
	2007	2006	Amount	Percent
	(dollars in thousands)			
Revenues:				
Oil and gas sales	$ 39,246	$ 27,992	$ 11,254	40.2%
Sales from natural gas marketing activities	29,924	29,129	795	2.7%
Oil and gas well drilling operations	1,739	3,745	(2,006)	-53.6%
Well operations and pipeline income	1,292	2,486	(1,194)	-48.0%
Oil and gas price risk management, net	3,742	1,370	2,372	173.1%
Other	2	21	(19)	-90.5%
Total revenues	$ 75,945	$ 64,743	$ 11,202	17.3%

The increase in total revenues was attributable to the increase in the Company's oil and gas sales driven by the increased production offset partially by the decline in oil and natural gas commodity pricing.

Costs and Expenses

The Company's costs and expenses for the three months ended June 30, 2007 and 2006 are presented below.

	Three Months Ended June 30,		Change	
	2007	2006	Amount	Percent
	(dollars in thousands)			
Costs and expenses:				
Oil and gas production and well operations cost	$ 11,628	$ 6,830	$ 4,798	70.2%
Cost of natural gas marketing activities	28,780	28,471	309	1.1%
Cost of oil and gas well drilling operations	246	3,278	(3,032)	-92.5%
Exploration expense	6,780	1,898	4,882	257.2%
General and administrative expense	6,886	5,102	1,784	35.0%
Depreciation, depletion and amortization	17,429	7,605	9,824	129.2%
Total costs and expenses	$ 71,749	$ 53,184	$ 18,565	34.9%

The increase in total costs and expenses of $18.6 million was a reflection of the Company's growth over the past year which was fueled primarily by the reinvestment of the proceeds from the 2006 sale of undeveloped leasehold of $354 million into productive operating properties. Through both acquisitions and new non program drilling, the Company has substantially increased production resulting in higher costs and expenses. Both the increase in depreciation, depletion and amortization ("DD&A") expense of $9.8 million and oil and gas production and well operations costs of $4.8 million were a result of the Company's acquisitions of oil and gas properties, funded by the proceeds of the 2006 leasehold acreage sale, and the significant number of new wells drilled and being placed in service during 2007. The increase in exploration expense of $4.9 million was primarily due to the liquidated damages from an exploration agreement and the subsequent lease abandonment totaling $3.8 million.

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Oil and Gas Sales

The increase in Oil and Gas sales was primarily due to increased volumes of natural gas and oil of 54.3% partially offset by lower average sales prices of natural gas and oil. The increased volume of natural gas and oil contributed $13.8 million to oil and gas sales, while the decline in prices reduced oil and gas sales by $2.5 million for the net increase of $11.3 million for the second quarter of 2007 compared to 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 the fourth quarter 2006 and first quarter 2007 acquisitions and the significantly increased number of wells drilled by the Company for its own account over the past year. The oil and gas sales generated from the fourth quarter 2006 and first quarter 2007 acquisitions and their subsequent development were $7.8 million.

Oil and Natural Gas Production

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

	Three Months Ended June 30,		Change	
	2007	2006	Amount	Percent
Natural Gas (Mcf)				
Appalachian Basin	675,591	372,476	303,115	81.4%
Michigan Basin	420,390	355,244	65,146	18.3%
Rocky Mountains	3,945,077	2,366,987	1,578,090	66.7%
Total	5,041,058	3,094,707	1,946,351	62.9%
Average Sales Price	*$ 5.16*	*$ 5.54*	*$ (0.38)*	*-6.9%*
Oil (Bbls)				
Appalachian Basin	1,840	300	1,540	513.3%
Michigan Basin	1,167	904	263	29.1%
Rocky Mountains	229,471	177,982	51,489	28.9%
Total	232,478	179,186	53,292	29.7%
Average Sales Price	*$ 57.02*	*$ 60.55*	*$ (3.53)*	*-5.8%*
Natural Gas Equivalents (Mcfe)*				
Appalachian Basin	686,631	374,276	312,355	83.5%
Michigan Basin	427,392	360,668	66,724	18.5%
Rocky Mountains	5,321,903	3,434,879	1,887,024	54.9%
Total	6,435,926	4,169,823	2,266,103	54.3%
Average Sales Price	*$ 6.10*	*$ 6.71*	*$ (0.61)*	*-9.1%*

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

The majority of the increase in natural gas and oil volumes was the result of the Company's increased investment in oil and gas properties, primarily the fourth quarter 2006 and first quarter 2007 acquisitions and the significant increased number of wells drilled for the Company's own account over the past year. The production generated from the fourth quarter 2006 and first quarter 2007 acquisitions and their subsequent development was 1.2 Bcfe. This represents approximately half of the total 54.3% increase in production for the three months ended June 30, 2007, compared to the same period last year.

Late in the second quarter of 2007, the Company placed into service its upgraded Garden Gulch pipeline and compressor facility, which serves a majority of the Company's Piceance Basin wells. This upgrade included two new natural gas compressors and pipeline facility enhancements, which is expected to substantially increase the Company's capacity from the facility. The facility was added, in part, in anticipation of the Company’s drilling initiatives for 2007. Additional enhancements to the facility are planned for the third quarter of 2007, which will position the Company to carry out its Piceance development plans in the future.

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Oil and Natural Gas Pricing

Financial results depend upon many factors, particularly the price of natural gas and the Company's ability to market its production effectively. Natural gas and oil prices have been among the most volatile of all commodity prices. These price variations can have a material impact on the Company's financial results. Natural gas and oil prices also vary by region and locality, depending upon the distance to markets, and the supply and demand relationships in that region or locality. This can be especially true in the Rocky Mountain Region as shown in the graph below. The combination of increased drilling activity and the lack of local markets can entail a local oversupply situation from time to time. There are a number of different pipelines in various stages of construction by other companies which will help to maintain a balance between supply and demand. However, there may be times in which there may be oversupply situations for short or longer terms, which may affect the amount of natural gas or oil that the Company can sell, and the price at which it sells natural gas or oil. Like most other producers in the region, the Company relies on major interstate pipeline companies to construct these facilities, causing the timing and availability of these facilities to be outside of the Company's control (see Natural Gas Pricing and Pipeline Capacity in Liquidity and Capital Resources).

Rocky Mountain Region Pricing

Although the Company's weighted average price for natural gas for the three months ended June 30, 2007, was $5.16 per Mcf, the price the Company receives for a majority of its natural gas produced in the Rocky Mountain Region is based on the Colorado Interstate Gas Index ("CIG"), which is currently less than the price received for natural gas produced in the eastern regions which is New York Mercantile Exchange ("NYMEX") based. The natural gas price in the eastern regions, where 21.7% of the Company's production for the quarter was located, was $7.20 per Mcf compared to our Rocky Mountain Region price per Mcf of $4.80. The Rocky Mountain Region produced 78.3% of the Company's natural gas for the quarter and is where the future production increases are scheduled to occur. The Company benefited during the current quarter through its derivative activities from the floors it had placed in the Rocky Mountain Region. The Company received $1.4 million in proceeds (gross, excluding the cost of floors) from its derivative instruments during the current quarter or $0.35 per Mcf, which helps to offset the lower prices it received for its Rocky Mountain Region natural gas. The Company reports its activities from derivative transactions under the oil and gas price risk management line item on the statements of income.

The graph below identifies the actual NYMEX and CIG natural gas prices by month from January 2006 through June 2007 and the forward curve for natural gas prices through June 2008 as of June 30, 2007. The forecasted prices in the graph have been derived from the sources indicated and represent, in the Company's opinion, a reasonable view of the possible movement of the CIG and NYMEX natural gas prices over the next year. However, because the prices given in the graph represent forecasts of future matters and are subject to future events which the Company cannot predict, the Company can give no reassurance that these forecasted prices will be as they are presented in the graph. An investor should therefore not rely on these forecasted prices in making an investment decision regarding the Company's stock.

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** Source: Derived from various sources including FutureSource, Inside FERCs Gas Market Report and ClearPort Trading.*

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While the above graph shows a large differential between current NYMEX and CIG pricing, the gap as shown above is expected to close this winter. Although 78.3% of the Company's production comes from the Rocky Mountain Region, the Company's Rocky Mountain natural gas and oil pricing is based upon other indices along with CIG.

The table below identifies the basis of the Company's natural gas and oil pricing on a sales volume basis. It further outlines that 37.2% of the Company's oil and natural gas sales is derived from the CIG index. The Company realized second quarter prices associated with its non CIG volumes at considerably higher prices.

Energy Market Exposure
as of June 30, 2007

Area	Pricing Basis	Commodity	Percent of Oil and Gas Sales
Piceance/Wattenberg	CIG	Gas	37.2%
Wattenberg/North Dakota	NYMEX	Oil	21.7%
NECO	Mid Continent Panhandle Eastern	Gas	15.9%
Appalachian	NYMEX	Gas	12.4%
Michigan	Mich-Con/NYMEX	Gas	8.5%
Wattenberg	Colorado Liquids	Gas	3.7%
Other	Other	Gas/Oil	0.6%
			100.0%

Natural Gas Marketing Activities

The increase in natural gas marketing activities was due to higher volumes of natural gas sold and slightly higher average sales prices due to the mix of its gas sales and the impact of derivative activities for the three months ended June 30, 2007. The increase in the costs of natural gas marketing activities was due to higher volumes of natural gas purchased and slightly higher average prices. Income before taxes for the Company's natural gas marketing subsidiary increased from $0.8 million for the three months ended June 30, 2006, to $1.3 million for the three months ended June 30, 2007.

Drilling Operations

In the first quarter of 2006, the Company, in addition to its remaining footage-based drilling arrangements, began recognizing revenues for its cost-plus drilling arrangements with its partnerships. The cost-plus drilling arrangements began with the private program partnership funded by the Company in late December 2005 and continued in the 2006 partnership funded September 2006, which started drilling operations in the third quarter of 2006 and continued through the second quarter of 2007. The Company's services provided under the cost-plus drilling arrangements are reported net of recovered costs and reflected as revenue in oil and gas well drilling operations. The decrease in revenue from oil and gas well drilling operations was due to the change in the Company's type of drilling contract. The three months ended June 30, 2006, oil and gas well drilling operations includes $2.2 million of revenue from footage-based contracts with no material corresponding amounts being recognized for the three months ended June 30, 2007.

The decrease in cost of oil and gas well drilling operations was due to the Company's revenue reporting change from footage-based drilling arrangements to cost-plus drilling arrangements as described above.

The completion of the remaining footage-based arrangements, which incurred losses during 2006, improved the profitability of the drilling segment from a gross profit of $0.5 million for the three months ended June 30, 2006, to $1.5 million for the three months ended June 30, 2007.

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Well Operations and Pipeline Income

The decrease in well operations and pipeline income was due to the loss of revenues resulting from the acquisition of all outstanding partnership interests of 44 Company-sponsored drilling partnerships in the first quarter of 2007. With the Company now owning the 423 net wells purchased as a result of the partnership acquisitions in the first quarter, it no longer receives income for operating these wells and related pipelines. This decrease in revenue was offset in part by an increase in the number of new wells drilled and placed in service and pipeline systems operated by the Company for its drilling program partnerships as well as third parties.

Oil and Gas Price Risk Management, Net

For the three months ended June 30, 2007, the Company recorded unrealized gains of $3.7 million compared to unrealized gains of $1.3 million for the same prior year period. The change is a result of significant declines from March 31, 2006, to June 30, 2006, in both the CIG and NYMEX markets which increased the value of the Company's floors and resulted in the gains during the second quarter of last year. The decrease in NYMEX pricing from March 31, 2007, to June 30, 2007, along with increased derivative positions resulted in the unrealized gains recorded in the current quarter this year. As prices decline, the Company's derivative portfolio, which is comprised predominantly of floors, would increase in value and would result in gains. These gains were further impacted by a decline in NYMEX prices from the time new positions were added during the quarter verses the NYMEX at quarter end.

Oil and gas price risk management, net is comprised of realized and unrealized changes in the fair value of oil and natural gas derivatives related to the Company's oil and natural gas production. Oil and gas price risk management, net does not include commodity based derivative transactions related to transactions from marketing activities, which are included in sales from and cost of natural gas marketing activities.

Oil and Natural Gas Derivative Activities

Because of uncertainty surrounding natural gas and oil prices the Company has used various derivative instruments to manage some of the impact of fluctuations in prices. Through October 2008, the Company has in place a series of floors and ceilings on a portion of the natural gas and oil production. Under the arrangements, if the applicable index rises above the ceiling price, the Company pays the counterparty; however, if the index drops below the floor, the counterparty pays the Company. During the three months ended June 30, 2007, the Company averaged natural gas volumes sold of 1.7 Bcf per month and oil sales of 77,000 Bbls per month.

The positions in effect as of August 9, 2007, 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)					
Feb-06	Jul 2007 - Oct 2007	44,000	$ 5.50	-	$ -
Sep-06	Jul 2007 - Oct 2007	194,500	4.50	-	-
Dec-06	Nov 2007 - Mar 2008	100,000	5.25	-	-

Jan-07	Nov 2007 - Mar 2008	100,000	5.25	100,000	9.80
May-07	Apr 2008 - Oct 2008	197,250	5.50	197,250	10.35

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NYMEX Based Derivatives - (Appalachian and Michigan Basins)

Feb-06	Jul 2007- Oct 2007	85,000	$	7.00	-	$	-
Feb-06	Jul 2007- Oct 2007	85,000		7.50	85,000		10.83
Sep-06	Jul 2007- Oct 2007	85,000		6.25	-		-
Jan-07	Jul 2007- Oct 2007	85,000		5.25	-		-
Dec-06	Nov 2007 - Mar 2008	144,500		7.00	-		-
Jan-07	Nov 2007 - Mar 2008	144,500		7.00	144,500		13.70
Jan-07	Apr 2008 - Oct 2008	144,500		6.50	144,500		10.80
May-07	Apr 2008 - Oct 2008	120,000		7.00	120,000		13.00

Panhandle Based Derivatives (NECO)

Feb-06	Jul 2007 - Oct 2007	60,000	$	6.00	-	$	-
Feb-06	Jul 2007 - Oct 2007	60,000		6.50	60,000		9.80
Jan-07	Jul 2007 - Oct 2007	90,000		4.50	-		-
Dec-06	Nov 2007 - Mar 2008	70,000		5.75	-		-
Jan-07	Nov 2007 - Mar 2008	90,000		6.00	90,000		11.25
Jan-07	Apr 2008 - Oct 2008	90,000		5.50	90,000		9.85
Jun-07	Apr 2008 - Oct 2008	90,000		6.00	90,000		11.25

Colorado Interstate Gas (CIG) Based Derivatives (DJ Basin)

Jan-07	Jul 2007 - Oct 2007	221,000	$	4.00	-	$	-
Jan-07	Nov 2007 - Mar 2008	120,000		5.25	120,000		9.80
May-07	Apr 2008 - Oct 2008	306,000		5.50	306,000		10.35

Oil - NYMEX Based (Wattenberg/ND)

Sep-06	Jul 2007 - Oct 2007	12,350	$	50.00	-	$	-

Oil and Gas Production and Well Operations Costs

The increase in oil and gas production and well operations costs was primarily attributable to the 54.3% increase in production volumes and the increased number of wells and pipeline systems operated by the Company due to the Company's first quarter acquisitions. Also, in 2007, there has been a significant increase in drilling activity for the Company’s own account, along with rising costs of oil field services, including the increase in the production and engineering staff of the Company. While the overall rate of oil and gas production and well operations costs increased by $4.8 million from the second quarter of 2006 to 2007, the majority of the increase is explained by the 54.3% increase in production. On a unit of production basis, the increase in oil and gas production and well operations costs increased by 10.4% from $1.64 per Mcfe for the second quarter 2006 to $1.81 per Mcfe for the second quarter 2007. Oil and gas production and well operations costs also include the cost of operating wells and pipeline systems for the Company-sponsored partnership drilling programs and other third parties. On a unit of production basis, a net cost of $1.61 per Mcfe for the three months ended June 30, 2007, compared to $1.04 per Mcfe for the same prior year period, is obtained by subtracting the revenue generated from well operations and pipeline income from the oil and gas production well operations costs to arrive at a net cost per Mcfe.

The reason for the increase is the additional production and engineering staff of the Company, increased maintenance and operating cost of the new pipeline and compressor upgrades and improvements, increased production enhancements and workovers associated with the fourth quarter 2006 and the first quarter 2007 acquisitions and general oil field services inflation pressures. The increase in staff has positioned the Company to be able to achieve its planned 2007 capital budget, which consists of drilling approximately 400 wells, almost all of which will be operated by the Company.

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Exploration Expense

The Company was party to an exploration agreement with an unaffiliated party, which required the Company to drill a minimum of 25 exploratory wells through June 30, 2007. For each well the Company failed to drill prior to June 30, 2007, the Company was required to pay liquidated damages equal to $125,000 per undrilled well. After drilling three exploratory wells, the Company determined, based on drilling results, not to drill the remaining 22 exploratory wells. During the quarter ended June 30, 2007, the Company recorded charges to exploration expense for the liquidated damages of $2.7 million related to the 22 undrilled wells and $1.1 million related to the write-off of the carrying value of the acreage resulting from the abandonment of the project to exploration expense in the second quarter of 2007. With regard to the liquidated damages and while the Company acknowledges its liability, the Company is currently negotiating an alternative settlement of this liability. However, there can be no assurance that an alternative settlement will be reached.

General and Administrative Expense

The increase in general and administrative expense was due to the Company's increased audit costs, the restatement of the Company-sponsored partnerships' financial statements, increased costs of complying with the various provisions of Sarbanes-Oxley, in particular Section 404, *Internal Controls*, accounting assistance from third party consulting services and increased payroll and payroll related costs. The Company expects these higher compliance costs to continue throughout 2007.

On a per unit of production basis, the Company's general and administrative expenses decreased from $1.22 per Mcfe for the second quarter of 2006 to $1.07 for the second quarter of 2007. General and administrative expenses on a per unit of production basis also declined from $1.39 in the first quarter of 2007.

Depreciation, Depletion and Amortization

Higher production levels resulted in a $3.8 million increase in DD&A for the quarter ended June 30, 2007, compared to the same period a year ago. The remainder of the period to period change includes $3 million related to acquisitions of proved mineral interests and $2.9 million related to additions of wells and related equipment and facilities.

Gain on Sale of Leaseholds

In July 2006, the Company and an unaffiliated party entered into a purchase and sale agreement regarding the sale of the Company's undeveloped leasehold located in the Grand Valley Field, Garfield County, Colorado ("PSA"), as filed with the Securities and Exchange Commission ("SEC") as Exhibit 10.3 to the Form 10-Q for the period ended June 30, 2006. On May 31, 2007, the Company and the unaffiliated party entered into a letter agreement amending the PSA. The letter agreement relieved the Company of its obligation, in its entirety, to either drill 16 wells on specifically identified acreage over the next three years, at the Company's cost and the Company's benefit, or pay liquidated damages of $1.6 million per undrilled well. As a result, the Company recognized the related, remaining deferred gain on sale of leaseholds of $25.6 million as a gain on the sale of leaseholds in the second quarter of 2007.

Non-operating Income/Expense

	Three Months Ended June 30,		Change	
	2007	2006	Amount	Percent
		(dollars in thousands)		

Non-operating income (expense):				
Interest income	$ 454	$ 349	$ 105	30.1%
Interest expense	(1,450)	(436)	(1,014)	232.6%

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The increase in interest expense was due to significantly higher average outstanding balances of the Company's credit facility, offset by capitalized construction period interest of $0.8 million and $0.4 million for the three months ended June 30, 2007 and 2006, respectively. The Company utilizes its daily cash balances to reduce its line of credit to lower its costs of interest.

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes for the three months ended June 30, 2007, was 37.3% compared to 36.5% for the same prior year period. The increase in the tax rate was primarily due to a smaller portion of the Company's wells qualifying for "percentage depletion deduction" resulting in a larger temporary tax difference in 2007 versus a permanent tax deduction in 2006.

Six Months Ended June 30, 2007, Compared to Six Months Ended June 30, 2006

Revenues

The Company's revenues for the six months ended June 30, 2007 and 2006, are presented below.

	Six Months Ended June 30,		Change	
	2007	2006	Amount	Percent
	(dollars in thousands)			
Revenues:				
Oil and gas sales	$ 73,262	$ 56,324	$ 16,938	30.1%
Sales from natural gas marketing activities	51,911	71,071	(19,160)	-27.0%
Oil and gas well drilling operations	5,769	9,023	(3,254)	-36.1%
Well operations and pipeline income	4,590	4,776	(186)	-3.9%
Oil and gas price risk management, net	(1,903)	6,295	(8,198)	-130.2%
Other	228	24	204	850.0%
Total revenues	$ 133,857	$ 147,513	$ (13,656)	-9.3%

The decline in revenues of $13.7 million is primarily due to a decrease in natural gas sales from marketing activities of $19.2 million and oil and gas price risk management of $8.2 million. Both of these declines in revenues are a result of large unrealized derivative gains during the six months ended June 30, 2006, a consequence of the decline in natural gas prices from the extremely high natural gas prices at the end of 2005 driven by the 2005 active hurricane season in the Gulf. Oil and natural gas sales increased $16.9 million as a result of the increase in production of 49.9% although commodity prices declined 13.4%.

Cost and Expenses

The Company's costs and expenses for the six months ended June 30, 2007 and 2006, are presented below.

	Six Months Ended June 30,		Change	
	2007	2006	Amount	Percent
	(dollars in thousands)			
Costs and expenses:				
Oil and gas production and well operations cost	$ 20,663	$ 13,779	$ 6,884	50.0%
Cost of natural gas marketing activities	50,292	70,251	(19,959)	-28.4%

Cost of oil and gas well drilling operations	810	7,490	(6,680)	-89.2%
Exploration expense	9,458	3,106	6,352	204.5%
General and administrative expense	14,310	8,821	5,489	62.2%
Depreciation, depletion, and amortization	30,503	14,192	16,311	114.9%
Total costs and expenses	$ 126,036	$ 117,639	$ 8,397	7.1%

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The increases in oil and gas production costs of $6.9 million and DD&A of $16.3 million was a reflection of the Company's growth over the past year, fueled primarily by the reinvestment of the proceeds from the 2006 sale of undeveloped leasehold of $354 million into productive operating properties. Through both acquisitions and new non program drilling, the Company has substantially increased production resulting in higher costs and expenses. Both the increase in DD&A and oil and gas production and well operations costs were a result of the Company's acquisitions of oil and gas properties funded by the proceeds of the 2006 leasehold acreage sale, and the significant number of new wells drilled and being placed in service during 2007. The increase in exploration expense of $6.4 million was primarily due to the liquidated damages from an exploration agreement and the subsequent lease abandonment totaling $3.8 million. The decline in natural gas marketing costs of $20 million corresponds to the decline in sales from natural gas marketing activities as referenced above. The costs of oil and gas well drilling declined as a result of the Company changing its type of drilling contract.

Oil and Gas Sales

The increase in oil and gas sales was primarily due to increased volumes of natural gas and oil of 49.9% partially offset by lower average sales prices of natural gas and oil. The increased volume of natural gas and oil contributed $24.4 million to oil and gas sales, while the decline in prices reduced oil and gas sales by $7.5 million for the net increase of $16.9 million from the comparable period. The increase in natural gas and oil volumes was the result of the Company's increased investment in oil and gas properties, primarily the fourth quarter 2006 and first quarter 2007 acquisitions and the significantly increased number of wells drilled by the Company for its own account over the past year. The oil and gas sales generated from the fourth quarter 2006 and first quarter 2007 acquisitions and their subsequent development were $13.9 million.

Oil and Natural Gas Production

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

	Six Months Ended June 30,		Change	
	2007	2006	Amount	Percent
Natural Gas (Mcf)				
Appalachian Basin	1,284,988	780,901	504,087	64.6%
Michigan Basin	841,277	711,536	129,741	18.2%
Rocky Mountains	7,050,746	4,514,950	2,535,796	56.2%
Total	9,177,011	6,007,387	3,169,624	52.8%
Average Sales Price	*$ 5.56*	*$ 6.33*	*$ (0.77)*	*-12.2%*
Oil (Bbls)				
Appalachian Basin	3,214	789	2,425	307.4%
Michigan Basin	1,982	1,993	(11)	-0.6%
Rocky Mountains	426,821	304,117	122,704	40.3%
Total	432,017	306,899	125,118	40.8%
Average Sales Price	*$ 51.49*	*$ 59.61*	*$ (8.12)*	*-13.6%*
Natural Gas Equivalents (Mcfe)*				
Appalachian Basin	1,304,272	785,635	518,637	66.0%
Michigan Basin	853,169	723,494	129,675	17.9%

Rocky Mountains		9,611,672		6,339,652	3,272,020	51.6%
Total		11,769,113		7,848,781	3,920,332	49.9%
Average Sales Price	*$*	*6.22*	*$*	*7.18*	*$ (0.96)*	*-13.4%*

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

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The majority of the increase in natural gas and oil volumes was the result of the Company's increased investment in oil and gas properties, primarily the fourth quarter 2006 and first quarter 2007 acquisitions and the significant increased number of wells drilled for the Company's own account over the past year. The production generated from the fourth quarter 2006 and first quarter 2007 acquisitions and their subsequent development was 2.1 Bcfe. This represents 54% of the total 49.9% increase in production for the six months ended June 30, 2007, compared to the same period last year.

Late in the second quarter of 2007, the Company placed into service its upgraded Garden Gulch pipeline and compressor facility, which serves a majority of the Company's Piceance Basin wells. This upgrade included two new natural gas compressors and pipeline facility enhancements, which is expected to substantially increase the Company's capacity from the facility. The facility was added, in part, in anticipation of the Company’s drilling initiatives for 2007. Additional enhancements to the facility are planned for the third quarter of 2007, which will position the Company to carry out its Piceance development plans in the future.

Oil and Natural Gas Pricing

Financial results depend upon many factors, particularly the price of natural gas and the Company’s ability to market its production effectively. Natural gas and oil prices have been among the most volatile of all commodity prices. These price variations can have a material impact on the Company’s financial results. Natural gas and oil prices also vary by region and locality, depending upon the distance to markets and the supply and demand relationships in that region or locality. This can be especially true in the Rocky Mountain Region. The combination of increased drilling activity and the lack of local markets can entail a local oversupply situation from time to time. There are a number of different pipelines in various stages of construction by other companies which will help to maintain a balance between supply and demand. However, there may be times in which there may be oversupply situations for short or longer terms, which may affect the amount of natural gas or oil that the Company can sell, and the price at which it sells natural gas or oil. Like most other producers in the region, the Company relies on major interstate pipeline companies to construct these facilities, causing the timing and availability of these facilities to be outside of the Company’s control (see Natural Gas Pricing and Pipeline Capacity in Liquidity and Capital Resources).

Rocky Mountain Region Pricing

Although the Company’s weighted average price for natural gas for the six months ended June 30, 2007, was $5.56 per Mcf, the price the Company receives for a majority of its natural gas produced in the Rocky Mountain Region is based on the CIG index which is currently less than the price received for natural gas produced in the eastern regions which is NYMEX based. The natural gas price in the eastern regions, where 23.2% of production for the six months was located, was $6.82 per Mcf compared to the Company’s Rocky Mountain Region price per Mcf of $5.26. The Rocky Mountain Region produced 76.8% of the natural gas for the six months, and is where the future production increases are scheduled to occur. The Company benefited during the current six months through its derivative activities from the floors it had placed in the Rocky Mountain Region. The Company received $1.9 million in proceeds (gross, excluding the cost of floors) from its derivative instruments during the first six months, or $0.27 per Mcf, which helps to offset the lower prices it received for its Rocky Mountain Region natural gas. The Company reports its activities from derivative transactions under the oil and gas price risk management line item on the income statement. See three month discussion and analysis of Oil and Natural Gas Pricing above.

Natural Gas Marketing Activities

The decrease in sales from natural gas marketing activities was due to lower average price of natural gas sold and unrealized losses on derivative transactions, which were $1.3 million for the six months ended June 30, 2007, partially offset by higher volumes, compared to unrealized gains of $19.3 million for the six months ended June 30, 2006. The decrease in costs of natural gas marketing activities was due to lower prices and unrealized gains on derivative transactions, which were $1.3 million for the six months ended June 30, 2007, partially offset by higher volumes of natural gas purchased, compared to unrealized losses on derivative transactions of $20.1 million for the six months ended June 30, 2006. Income before income taxes for the Company's natural gas marketing segment increased from a profit of $1.1 million for the six months ended June 30, 2006, to a $2.0 million profit for the six months ended June 30, 2007.

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Drilling Operations

In the first quarter of 2006, the Company, in addition to its remaining footage-based drilling arrangements, began recognizing revenues for its cost-plus drilling arrangements with its partnerships. The cost-plus drilling arrangements began with the private program partnership funded by the Company in late December 2005 and continued in the 2006 partnership funded in September 2006, which started drilling operations in the third quarter of 2006 and continued through the second quarter of 2007. The Company's services provided under the cost-plus drilling arrangements are reported net of recovered costs and reflected as revenue in oil and gas well drilling operations. The decrease in revenues from oil and gas well drilling operations was due to this change in the Company's type of drilling contract. The six months ended June 30, 2006, revenue included $4.1 million from footage-based contracts, with no material corresponding amounts being recognized for the six months ended June 30, 2007.

The decrease in cost of oil and gas well drilling operations was due to the Company's revenue reporting for its cost-plus drilling arrangements as described above.

The completion of the remaining footage-based arrangements, which incurred losses during 2006, improved the profitability of the drilling segment from a gross profit of $1.5 million for the six months ended June 30, 2006, to $5 million for the six months ended June 30, 2007.

Well Operations and Pipeline Income

The decrease in well operations and pipeline income was due to the loss of revenues resulting from the acquisition of all outstanding partnership interests of 44 Company-sponsored drilling partnerships in the first quarter of 2007. With the Company now owning the 423 net wells purchased as a result of the partnership acquisitions in the first quarter, it no longer receives income for operating these wells and related pipelines. This decrease in revenue was offset in part by an increase in the number of new wells drilled and placed in service and pipeline systems operated by the Company for its drilling program partnerships as well as third parties.

Oil and Gas Price Risk Management, Net

For the six months ended June 30, 2007, the Company recorded unrealized losses of $2.5 million and realized gains of $0.6 million compared to unrealized gains of $4.9 million and realized gains of $1.4 million for the same prior year period. The change is a result of a significant decline from record pricing during the December 31, 2005 to June 30, 2006 time period, in both the CIG and NYMEX markets, which increased the value of the Company's floors and resulted in the gains during the first quarter of last year. The CIG and NYMEX pricing increase from December 31, 2006, to June 30, 2007, along with the increased derivative positions resulted in the unrealized losses recorded in the current six month period. As prices decline, the Company's derivative portfolio, which is comprised predominantly of floors, would increase in value and would result in gains. These gains were further impacted by a decline in NYMEX prices from the time new positions were added during the six months verses the NYMEX at period end.

Oil and gas price risk management, net is comprised of realized and unrealized changes in the fair value of oil and natural gas derivatives related to the Company's oil and natural gas production. Oil and gas price risk management, net does not include commodity based derivative transactions related to transactions from marketing activities, which are included in sales from and cost of natural gas marketing activities.

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Oil and Gas Production and Well Operations Costs

The increase in oil and gas production and well operations costs was primarily attributable to the 49.9% increase in production volumes and the increased number of wells and pipeline systems operated by the Company due to the Company's first quarter acquisitions. Also, in 2007 there has been a significant increase in drilling activity for the Company's own account. While the overall cost of oil and gas production and well operations increased by $6.9 million, from the first six months of 2006 compared to the same period for 2007, the majority of the increase is explained by the 49.9% increase in production. On a unit of production basis, the increase in oil and gas production and well operations costs was offset by the increase in production, with the rate remaining unchanged at $1.76 per Mcfe. Oil and gas production and well operations costs also include the cost of operating wells and pipeline systems for Company-sponsored partnership drilling programs and other third parties. On a unit of production basis, a net cost of $1.37 per Mcfe for the six months ended June 30, 2007, compared to $1.15 per Mcfe for the same prior year period, is obtained by subtracting the revenue generated from well operations and pipeline income from the oil and gas production well operations costs to arrive at a net cost per Mcfe. The increase in cost is also due to additional production and engineering staff of the Company, and the increased maintenance and operating costs of the new pipeline and compressor upgrades and improvements, increased production enhancements and workover costs associated with the fourth quarter 2006 and the first quarter 2007 acquisitions and general oil field services inflation pressures. The increase in staff has positioned the Company to be able to achieve its planned 2007 capital budget, which consists of drilling approximately 400 wells, almost all of which will be operated by the Company.

Exploration Expense

The Company was party to an exploration agreement with an unaffiliated party, which required the Company to drill a minimum of 25 wells through June 30, 2007. For each well the Company failed to drill prior to June 30, 2007, the Company was required to pay liquidated damages equal to $125,000 per undrilled well. After drilling three exploratory wells, the Company determined, based on drilling results, not to drill the remaining 22 exploratory wells. During the second quarter of 2007, the Company recorded charges to exploration expense for the liquidated damages of $2.7 million related to the 22 undrilled wells and $1.1 million related to the write-off of the carrying value of the acreage resulting from the abandonment of the project to exploration expense in the second quarter of 2007. With regard to the liquidated damages and while the Company acknowledges its liability, the Company is currently negotiating an alternative settlement of this liability. However, there can be no assurance that an alternative settlement will be reached.

General and Administrative Expense

The increase in general and administrative expense was due to the Company's increased audit costs, the restatement of the Company-sponsored partnerships' financial statements, increased costs of complying with the various provisions of Sarbanes-Oxley, in particular Section 404, *Internal Controls*, accounting assistance from third party consulting services and increased payroll and payroll related costs. The Company expects these higher compliance costs to continue throughout 2007.

On a per unit of production basis, the Company's general and administrative expense increased from $1.12 per Mcfe for the six months of 2006 to $1.22 for the six months of 2007.

Depreciation, Depletion and Amortization

Higher production levels resulted in a $7 million increase in DD&A for the six months ended June 30, 2007, compared to the same period a year ago. The remainder of the period to period change includes $5.5 million related to acquisitions of proved mineral interests and $3.2 million related to additions of wells and related equipment and facilities.

Gain on Sale of Leaseholds

See the three month discussion and analysis of Gain on Sale of Leaseholds above.

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Non-operating Income/Expense

	Six Months Ended June 30,		Change	
	2007	2006	Amount	Percent
	(dollars in thousands)			
Non-operating income (expense):				
Interest income	$ 1,597	$ 741	$ 856	115.5%
Interest expense	(2,281)	(788)	(1,493)	189.5%

The increase in interest income was due to interest earned on the investment of cash proceeds from the sale of undeveloped leaseholds during the first quarter of 2007. The increase in interest expense was due to significantly higher average outstanding balances of our credit facility, offset by capitalized construction period interest of $1.3 million and $0.4 million for the six months ended June 30, 2007 and 2006, respectively. The Company utilizes its daily cash balances to reduce its line of credit to lower its costs of interest.

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes for the six months ended June 30, 2007, was 37.2% compared to 36.6% for the same prior year period. The increase in the tax rate was primarily due to a smaller portion of the Company's wells qualifying for “percentage depletion deduction” resulting in a larger temporary difference in 2007 versus a permanent tax deduction in 2006.

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 positive operating cash flow being recognized by the Company. 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 indices that reflect current market prices for the commodity. As a result, variations in the market are reflected in the revenue the Company receives. 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 six months of 2007, prices for natural gas decreased from the last part of 2006 but remained relatively strong, and future expectations as reflected in the NYMEX futures market are for continuing high price levels for the remainder of 2007 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 natural gas production operations.

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Financial results depend upon many factors, particularly the price of natural gas and the Company's ability to market its production effectively. Natural gas and oil prices have been among the most volatile of all commodity prices. These price variations can have a material impact on the Company's financial results. Natural gas and oil prices also vary by region and locality, depending upon the distance to markets, and the supply and demand relationships in that region or locality. This can be especially true in the Rocky Mountain region. The combination of increased drilling activity and the lack of local markets can entail a local oversupply situation from time to time. Such a situation currently exists in the Rocky Mountain region, with production exceeding the local market demand and pipeline capacity to more distant markets. The result, beginning in the second quarter of 2007, has been a decrease in the price of Rocky Mountain natural gas compared to the NYMEX price and other markets. The Company expects this situation to continue until cold weather returns and/or new pipeline capacity for moving gas from the region is placed in service. In particular, the Rockies Express pipeline, once in service, is expected to improve the region's pricing compared to other markets. The second of three legs is scheduled to go into service in early 2008. Once the third leg and compression work on the pipeline are complete, expected for late 2008 or early 2009, the pipeline will move 1.8 Bcf/per day of natural gas from the region. Like most other producers in the region, the Company relies on major interstate pipeline companies to construct these facilities, causing the timing and availability of these facilities to be outside of the Company's control.

Oil Pricing

Oil prices have been near or at record levels for most of the last few years and continued into 2007. 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 sales accounted for 30.3% of the Company's oil and gas sales during the first six months of 2007 compared to 32.5% for the same prior year period.

Oil and Natural Gas Derivative Activities

Because of the uncertainty surrounding natural gas and oil prices, the Company has used various derivative instruments to manage some of the impact of fluctuations in prices. Through October 2008, we have in place a series of floors and ceilings on part of the natural gas and oil production. Under the arrangements, if the applicable index rises above the ceiling price, the Company pays the counterparty; however, if the index drops below the floor, the counterparty pays the Company. 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. The Company's derivative transactions do not currently qualify for hedge accounting under Statement of Financial Accounting Standard No. 133. Therefore, PDC records its derivative gains and losses, both realized and unrealized, through oil and gas price risk management for its share of production. The Company is required to mark-to-market its derivative positions at the end of each period and record the adjustment to the consolidated statement of income. This may and does cause wide variability in profits from period to period.

During the six months ended June 30, 2006, the Company recognized oil and gas price risk management gains of $1.4 million compared to gains for the six months ended June 30, 2007, of $0.6 million.

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Drilling Programs

In September 2006, the Company funded a drilling partnership, Rockies Region 2006 Limited Partnership, with subscriptions of approximately $90 million. Upon closing, 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. Drilling operations commenced in September 2006, and have continued into the second quarter of 2007. All of the 2006 partnership's 97 wells have been drilled as of June 30, 2007, and completion and equipping operations will continue through the third quarter of 2007.

The Company is currently offering its 2007 drilling partnership, Rockies Region 2007 Limited Partnership, and, as of August 7, 2007, has received subscriptions of $53 million, with a maximum amount of subscriptions of $110 million to be funded. The Company expects the partnership to be funded and drilling for the new program is scheduled to commence in the third quarter of 2007, with drilling and completion operations continuing through the first and second quarters of 2008. No assurance can be made that the Company will continue to receive this level of funding from this or future programs. 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. The Company expects to fund its equity contribution in the third quarter of 2007.

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 $6.1 million. The Company has adequate liquidity to meet this contingent obligation. During the first six months of 2007, the Company paid $0.7 million under this provision for the repurchase of partnership units.

2007 Capital Budget

The Company has established a $201 million exploration and development capital budget, which includes its equity contribution to the 2007 partnership and excludes acquisitions, if any, for 2007. The Company continues to explore for and evaluate possible acquisitions although no assurance can be given that any transaction will be consummated. The Company plans to drill approximately 400 wells under this budget for its own account and for its drilling program partnerships. The majority of the wells will be drilled in our Colorado fields. See the table listed below for the wells drilled through June 30, 2007.

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Drilling Activity

Development Wells. During the six months ended June 30, 2007, the Company and its drilling fund partnership drilled a total of 164 gross developmental wells as detailed by field below. Wells labeled as program wells were drilled for the benefit of the Company and its drilling fund partnership in which the Company has a 37% working interest, while wells labeled as non-program were drilled for the benefit of the Company.

	Development Wells *(gross)*		
	Successful	Dry	Total
Program			
Wattenberg	19	1	20
Piceance	3	-	3
	22	1	23
Non Program			
Michigan	2	-	2
Wattenberg	45	-	45
Piceance	27	-	27
NECO	61	6	67
	135	6	141
Total			
Michigan	2	-	2
Wattenberg	64	1	65
Piceance	30	-	30
NECO	61	6	67
	157	7	164

Exploratory Wells. During the six months ended June 30, 2007, the Company drilled for the benefit of the Company and its drilling fund partnership, five exploratory wells. Two of these wells were drilled on the Company's North Dakota Nesson acreage and three wells were drilled on the Colorado Wattenberg acreage. Of the five exploratory wells, two were determined to be dry, one in each field.

Garden Gulch Road – Piceance Basin

During the second quarter of 2007, the Company, with several other operators in the Piceance Basin, completed construction and placed into service an access road from the valley floor to the top of the Mesa ("Garden-Gulch Road"). The Company's share of the initial cost of the road was $5.1 million, substantially all of which has been paid as of June 30, 2007. The Garden Gulch Road is adjacent to the Company's compressor facilities in the valley and will improve access to approximately 450 drill sites on top of the Mesa. The road will allow the Company more efficient access to the top of the Mesa and potential cost savings in its drilling, completion and production activities. The road may also allow the Company to conduct drilling operations during the winter on the Mesa, which in prior years was not possible.

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Oil and Gas Properties

The following table identifies the costs incurred by the Company in oil and gas property acquisition, exploration and development for the six months ended June 30, 2007.

		Amount *(in thousands)*
Acquisition of properties:		
Unproved properties	$	22,229
Proved properties		196,606
Development costs		75,162
Exploration costs		6,303
Total costs incurred	$	300,300

Common Stock Buyback Program

On October 16, 2006, the Board of Directors of the Company approved a stock 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 times and in amounts that management deems appropriate. The Company may terminate or limit the stock purchase program at any time. For the six months ended June 30, 2007, the Company purchased 6,754 shares at a cost of $342,832 ($50.76 average price per share).

Working Capital

The Company's working capital as of June 30, 2007, is negative $36.7 million. At June 30, 2007, the Company had an activated line of credit with an additional borrowing capacity of $11 million under its existing line. The Company has historically managed its working capital needs by only drawing from its credit facility as liabilities come due and cash was required. As of August 9, 2007, the Company added a third bank to its existing facility, increasing its borrowing capacity by an additional $50 million. However, due to the Company's significant acquisitions made in 2007, and the substantial increase in capital expenditure levels, the Company is taking steps to increase its liquidity through alternative financings such as expanded commercial bank arrangements and capital markets transactions. If the Company is unable to complete such arrangements or transactions, future capital expenditures may be impacted.

Long-Term Debt

The Company has a credit facility with JPMorgan Chase Bank, N.A. ("JPMorgan") and BNP Paribas of $200 million subject to and collateralized by required levels of oil and natural gas reserves. Effective July 5, 2007, the Company's current borrowing base, based upon current oil and natural gas reserves, was increased from $135 million to $150 million, which is fully activated. The Company is required to pay a commitment fee of 0.25% to 0.375% per annum on the unused portion of the activated credit facility. Interest accrues at an alternative base rate ("ABR") or adjusted LIBOR at the discretion of the Company. The ABR is the greater of JPMorgan's prime rate, an adjusted secondary market rate for a three-month certificate of deposit plus 1% or the federal funds effective rate plus 0.5%. ABR borrowings are assessed an additional margin spread up to 0.375% and adjusted LIBOR borrowings are assessed an additional margin spread of 1.125% to 1.875%. The margin spread charges are based upon the outstanding balance under the credit facility. No principal payments are required until the credit agreement expires on November 4, 2010.

As of June 30, 2007, the outstanding balance under the credit facility was $124 million compared to $117 million, excluding the overline note discussed in Note 11 to the accompanying condensed consolidated financial statements, as of December 31, 2006. Any amounts outstanding under the credit facility are collateralized by substantially all the properties of the Company. At June 30, 2007, the outstanding balance was subject to an ABR of 8.625%. The credit agreement requires, among other things, the existence of satisfactory levels of oil and natural gas reserves and the maintenance of certain working capital and tangible net worth ratios. At June 30, 2007, the Company was not in compliance with its current ratio covenant.

Effective August 9, 2007, the Company amended its credit facility adding a new bank, Wachovia Bank, N.A. and increasing its aggregate commitments from $150 million to $200 million. The amendment also waives the working capital covenant until the earlier of (i) a debt or equity transaction resulting in net proceeds to the Company of at least $200 million or (ii) July 1, 2008. Under the amended agreement the ABR rate was increased by 0.375% as long as the waiver of the Company's non-compliance with the working capital covenant is in effect.

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The Company believes that after this amendment the Company will be able to sustain compliance with all covenants.

Contractual Obligations and Contingent Commitments

The following table represents the contractual obligations of the Company as of June 30, 2007.

Contractual Obligations and Contingent Commitments	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
		Payments due by period (*in thousands*)			
Debt	$ 124,000	$ -	$ -	$ 124,000	$ -
Operating Leases	4,059	1,759	1,857	443	-
Asset Retirement Obligations	17,509	50	200	200	17,059
Drilling Rig Commitments	35,260	13,594	21,429	237	-
Derivative Agreements (1)	5,965	3,692	2,273	-	-
Other Liabilities (2)	9,266	1,509	2,085	153	5,519
Total	$ 196,059	$ 20,604	$ 27,844	$ 125,033	$ 22,578

(1) *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 natural 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 receivable from the partnerships of $2 million as of June 30, 2007.*

(2) *Includes unrecognized tax benefits recorded pursuant to FIN No. 48 and other long-term obligations.*

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.

Drilling rig commitments in the above table do not include future adjustments to daily rates as provided for in the agreements as such increases are not predictable and are only included in the above obligation table upon notification to the Company by the contractor of an increase in the rate.

Commitments and Contingencies

As managing general partner of 32 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.

Recent Accounting Pronouncements

See Note 2, *Recent Accounting Standards*, to the Condensed Consolidated Financial Statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

The Company's exposure to market risk for changes in interest rates relates primarily to the Company's interest-bearing cash and cash equivalents, designated cash and long-term debt. Interest-bearing cash and cash equivalents includes money market funds, short-term certificates of deposit and checking and savings accounts with various banks. The amount of interest-bearing cash and cash equivalents as of June 30, 2007, is $29.5 million with an average interest rate of 4.34%. As of June 30, 2007, the Company had long-term debt of $124 million subject to a rate of 8.625%. Based on the June 30, 2007, credit facility borrowings, a 1% change in interest rates would have an annual $0.8 million after tax impact on the Company's financial statements.

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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. Company policy prohibits the use of oil and natural gas future and option contracts for speculative purposes. These instruments consist of NYMEX-traded natural gas futures contracts and option contracts for Appalachian and Michigan production, Panhandle-based contracts and NYMEX-traded contracts for NECO production and CIG-based contracts for other Colorado production. The Company purchases puts and participating collars for its own and affiliate partnerships production to protect against possible price instability in future periods while retaining much of the benefits of price increases. RNG enters into fixed-price physical purchase and sale agreements that are derivative contracts. In order to offset these fixed-price physical derivatives, the Company enters into financial derivative instruments that have the effect of locking in the prices the Company will recieve or pay for the same volumes and period, offsetting the physical derivative. 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 recived from price changes in the physical market.

The net fair value of the commodity based derivatives was $10.7 million and $13.6 million at June 30, 2007, and December 31, 2006, respectively. The Company recognized in the statement of income an unrealized loss on commodity based derivatives of $2.5 million for the six months ended June 30, 2007, and unrealized gains of $4.9 million for the six months ended June 30, 2006.

See Note 16, Derivative Financial Instruments, to the condensed consolidated financial statements, for a summary of the open derivative option and purchase and sales contracts for RNG and the Company as of June 30, 2007.

In addition to including the gross assets and liabilities related to the Company's share of oil and natural gas production, the summary of open derivative positions presented in Note 16 to the accompanying condensed consolidated financial statements 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 consolidated balance sheets include the fair value of derivatives and a corresponding net payable to the partnerships of $4.6 million as of June 30, 2007, and $7.5 million as of December 31, 2006.

The average CIG closing price for natural gas per Mmbtu for the six months ended June 30, 2007, and for the year 2006, was $4.68 and $6.27, respectively. The average NYMEX closing price for natural gas per Mmbtu for the six months ended June 30, 2007, and for the year 2006, was $7.16 and $7.88, respectively. The average NYMEX closing price for oil per bbl for the six months ended June 30, 2007, and for the year 2006, was $59.71 and $64.65, respectively. Future near-term natural 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

Material Weaknesses Previously Disclosed

As discussed in the Company’s 2006 Annual Report on Form 10-K, the Company did not maintain effective controls as of December 31, 2006, over (1) timely reconciliation, review and adjustment of significant balance sheet and income statement accounts, (2) proper accounting for the identification of certain derivative contracts to adequately determine the derivative’s fair value, and (3) proper accounting for oil and gas properties for capitalization of costs and that the calculations of depreciation and depletion were performed accurately.

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Evaluation of Disclosure Controls and Procedures

As of June 30, 2007, the Company carried out an evaluation under the supervision and with the participation of Management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), as to the effectiveness, design and operation of the Company's disclosure controls and procedures (as defined in Securities Exchange Act of 1934, Rule 13a-15(e) and 15d-15(e)). This evaluation considered the various processes carried out under the direction of the Company's disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports that the Company files or submits under the Exchange Act are recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that such information is accumulated and communicated to the Company's management, including the CEO and CFO, as appropriate, to allow timely discussion regarding required financial disclosure.

Based on the results of this evaluation, the CEO and the CFO concluded that as a result of the material weaknesses cited above, the Company's disclosure controls and procedures were not effective as of June 30, 2007. Because of these material weaknesses, the Company performed additional procedures to ensure that its financial statements as of and for the three and six months ended June 30, 2007, were fairly presented in all material respects in accordance with generally accepted accounting principles.

Changes in Internal Control Over Financial Reporting

There were no material changes in internal control over financial reporting during the second quarter of 2007. During the first quarter of 2007, and continuing through the filing of this Form 10-Q, the Company implemented the following changes in internal control over financial reporting:

- Reinforced reconciliation procedures to ensure the timely reconciliation, review and adjustments to significant balance sheet and income statement accounts;
- Developed and approved extensive policies and procedures concerning the controls over financial reporting for derivatives;
- Provided additional training regarding derivatives for key personnel;
- Developed a review process to ensure proper accounting for oil and gas properties, specifically the capitalization of costs and calculation of depreciation and depletion.

The Company continues to evaluate the ongoing effectiveness and sustainability of the changes the Company has made in internal control, and, as a result of the ongoing evaluation, may identify additional changes to improve internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings

From time to time, the Company is a party to various legal proceedings in the ordinary course of business. While it is not possible to determine with any degree of certainty the ultimate outcome of the following legal proceedings, the Company believes that it has meritorious defenses with respect to the claims asserted against it and intends to vigorously defend its position. An adverse outcome in the case below or any similar case could have a material adverse effect, individually and collectively, on the Company's financial position and results of operations.

Royalty Payments. On May 29, 2007, Glen Droegemueller, individually and as representative plaintiff on behalf of all others similarly situated, filed a class action complaint against the Company in the District Court, Weld County, Colorado alleging that the Company underpaid royalties on natural gas produced from wells operated by the Company in the State of Colorado (the "Droegemueller Action"). The plaintiff seeks declaratory relief and to recover an unspecified amount of compensation for underpayment of royalties made by the Company to the plaintiff pursuant to leases. The Company moved the case to Federal Court on June 28, 2007, and on July 10, 2007, the Company filed its answer and affirmative defenses. Given the preliminary stage of this proceeding and the inherent uncertainty in litigation, the Company is unable to predict the ultimate outcome of this suit at this time.

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Litigation similar to the Droegemueller Action has recently been commenced against several other companies in jurisdictions where the Company conducts business. While the Company's business model differs from that of the parties involved in such other litigation, and although the Company has not been named as a party in such other litigation, there can be no assurance that the Company will not be named as a party to such other litigation in the future.

Other. The Company is involved in various other legal proceedings that it considers normal to its business. The Company believes that the ultimate outcome of such other proceedings will not have a material adverse effect on its financial position or results of operations.

Item 1A. Risk Factors

The Company faces many risks. Factors that could materially adversely affect the Company's business, financial condition, operating results or liquidity and the trading price of common stock are described under "Risks Related to the Oil and Natural Gas Industry and the Company" in Item 1A of the Company's annual report on Form 10-K for the year ended December 31, 2006, as filed with the SEC on May 23, 2007. This information should be considered carefully, together with other information in this report and other reports and materials that the Company files, or has filed, with the SEC. There have been no material changes from the risk factors previously disclosed in the Company's 2006 Form 10-K.

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

(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
April 1-30, 2007	333	$ 53.14	333	1,474,110
May 1-31, 2007	3,663	50.05	3,663	1,470,447
June 1-30, 2007	92	50.99	92	1,470,355
	4,088	50.32	4,088	1,470,355

On October 16, 2006, the Board of Directors of the Company approved a stock 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 times and in amounts that management deems appropriate. The Company may terminate or limit the stock purchase program at any time. For the six months ended June 30, 2007, the Company purchased 6,754 shares at a cost of $342,832 ($50.76 average price per share).

Items 3, 4 and 5 have been omitted as there is nothing to report.

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Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description
10.1	Indemnification Agreement with Directors and Officers.
31.1	Rule 13a-14(a)/15d-14(a) Certification by Chief Executive Officer.
31.2	Rule 13a-14(a)/15d-14(a) Certification by Chief Financial Officer.
32	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.

SIGNATURES

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

Petroleum Development Corporation
(Registrant)

Date: August 9, 2007

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

Date: August 9, 2007

/s/ Richard W. McCullough
Richard W. McCullough
Chief Financial Officer