PETROLEUM DEVELOPMENT CORP
Form 10-Q
August 10, 2009

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

FORM 10-Q

T Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended June 30, 2009

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.)

1775 Sherman Street, Suite 3000
Denver, Colorado 80203
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (303) 860-5800

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 T No £

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes £ No £

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

Large Accelerated

accelerated filer T	filer £
Non-accelerated filer £	Smaller reporting company £

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes £ No T

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 14,905,591 shares of the Company's Common Stock ($.01 par value) were outstanding as of July 31, 2009.

PETROLEUM DEVELOPMENT CORPORATION

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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, 2009	December 31, 2008*
Assets		
Current assets:		
Cash and cash equivalents	$ 21,904	$ 50,950
Restricted cash - current	16,178	19,030
Accounts receivable, net	50,440	69,688
Accounts receivable - affiliates	16,655	16,742
Inventory	949	4,310
Fair value of derivatives - current	97,881	116,881
Prepaid expenses and other current assets	11,760	14,836
Total current assets	215,767	292,437
Properties and equipment, net	1,030,875	1,033,078
Fair value of derivatives - non current	13,928	47,155
Accounts receivable - affiliates - non current	12,876	1,605
Other assets	34,362	28,429
Total Assets	$ 1,307,808	$ 1,402,704
Liabilities and Equity		
Liabilities		
Current liabilities:		
Accounts payable	$ 35,766	$ 90,532
Accounts payable - affiliates	27,891	40,540
Production tax liability	22,061	18,226
Federal and state income taxes payable	1,078	1,591
Fair value of derivatives - current	8,325	4,766
Funds held for future distribution	43,527	50,361
Net deferred income taxes - current	15,855	28,355
Other accrued expenses	24,117	26,800
Total current liabilities	178,620	261,171
Long-term debt	418,512	394,867
Net deferred income taxes - non current	153,107	162,593
Asset retirement obligation	24,391	23,036
Fair value of derivatives - non current	38,198	5,720
Accounts payable - affiliates - non current	2,357	10,136
Other liabilities	16,332	32,906
Total liabilities	831,517	890,429
COMMITMENTS AND CONTINGENT LIABILITIES		
Equity		

Shareholders' equity:				
Preferred shares, par value $.01 per share; authorized 50,000,000 shares; issued: none		-		-
Common shares, par value $.01 per share; authorized 100,000,000 shares; issued: 14,889,611 in 2009 and 14,871,870 in 2008		149		149
Additional paid-in capital		8,659		5,818
Retained earnings		467,124		505,906
Treasury shares, at cost; 7,677 shares in 2009 and 7,066 in 2008		(303)		(292)
Total shareholders' equity		475,629		511,581
Noncontrolling interest in WWWV, LLC		662		694
Total equity		476,291		512,275
Total Liabilities and Equity	$	1,307,808	$	1,402,704

*Derived from audited 2008 balance sheet.

See accompanying notes to condensed consolidated financial statements.

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Petroleum Development Corporation
Condensed Consolidated Statements of Operations
(unaudited; in thousands, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Revenues:				
Oil and gas sales	$41,558	$94,549	$81,300	$166,195
Sales from natural gas marketing	12,367	30,941	34,756	54,266
Well operations and pipeline income	2,937	2,438	5,733	4,790
Oil and gas price risk management gain (loss), net	(23,284)	(101,798)	399	(144,108)
Other	11	34	53	37
Total revenues	33,589	26,164	122,241	81,180
Costs and expenses:				
Oil and gas production and well operations cost	14,044	21,330	30,405	39,533
Cost of natural gas marketing	11,992	30,117	33,870	52,238
Exploration expense	3,133	3,467	8,776	7,750
General and administrative expense	14,784	9,231	26,878	19,054
Depreciation, depletion and amortization	33,844	22,105	68,188	43,236
Total costs and expenses	77,797	86,250	168,117	161,811
Gain on sale of leaseholds	-	-	120	-
Loss from operations	(44,208)	(60,086)	(45,756)	(80,631)
Interest income	12	75	32	346
Interest expense	(9,420)	(6,394)	(17,803)	(11,326)
Loss from continuing operations before income taxes	(53,616)	(66,405)	(63,527)	(91,611)
Benefit for income taxes	(20,537)	(23,844)	(24,632)	(33,187)
Loss from continuing operations	(33,079)	(42,561)	(38,895)	(58,424)
Income from discontinued operations, net of tax	-	1,849	113	3,784
Net loss	$(33,079)	$(40,712)	$(38,782)	$(54,640)
Earnings (loss) per share				
Basic				
Continuing operations	$(2.23)	$(2.89)	$(2.63)	$(3.96)
Discontinued operations	-	0.13	0.01	0.25
Net loss	$(2.23)	$(2.76)	$(2.62)	$(3.71)
Diluted				
Continuing operations	$(2.23)	$(2.89)	$(2.63)	$(3.96)
Discontinued operations	-	0.13	0.01	0.25
Net loss	$(2.23)	$(2.76)	$(2.62)	$(3.71)
Weighted average common shares outstanding				
Basic	14,811	14,742	14,802	14,740
Diluted	14,811	14,742	14,802	14,740

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, 2009	Six Months Ended June 30, 2008
Cash flows from operating activities:		
Net loss	$(38,782)	$(54,640)
Adjustments to net loss to reconcile to cash provided by operating activities:		
Deferred income taxes	(21,986)	(20,156)
Depreciation, depletion and amortization	68,188	43,236
Exploratory dry hole costs	937	1,100
Amortization and impairment of unproved properties	1,132	942
Unrealized loss on derivative transactions	60,762	125,656
Other	7,155	3,457
Changes in assets and liabilities	(16,747)	(31,865)
Net cash provided by operating activities	60,659	67,730
Cash flows from investing activities:		
Capital expenditures	(104,371)	(126,786)
Other	328	177
Net cash used in investing activities	(104,043)	(126,609)
Cash flows from financing activities:		
Proceeds from credit facility	170,500	173,000
Repayment of credit facility	(147,000)	(357,000)
Proceeds from senior notes	-	200,101
Payment of debt issuance costs	(8,943)	(4,934)
Proceeds from exercise of stock options	-	367
Net tax benefit related to stock-based compensation plans	-	532
Purchase of treasury stock	(219)	(4,678)
Net cash provided by financing activities	14,338	7,388
Net decrease in cash and cash equivalents	(29,046)	(51,491)
Cash and cash equivalents, beginning of period	50,950	84,751
Cash and cash equivalents, end of period	$21,904	$33,260
Supplemental cash flow information:		
Cash payments for:		
Interest, net of capitalized interest	$16,196	$2,308
Income taxes, net of refunds	(3,600)	(1,865)
Non-cash investing activities:		
Change in accounts payable related to purchases of properties and equipment	(37,699)	(5,874)
Change in asset retirement obligation, with a corresponding increase to oil and gas properties, net of disposals	667	463

See accompanying notes to condensed consolidated financial statements.

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Petroleum Development Corporation
Notes to Condensed Consolidated Financial Statements
June 30, 2009
(unaudited)

1. GENERAL

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

The accompanying condensed consolidated financial statements include the accounts of PDC, our wholly owned subsidiaries and WWWV, LLC, an entity in which we have a controlling financial interest. All material intercompany accounts and transactions have been eliminated in consolidation. We account for our investment in interests in oil and natural gas limited partnerships under the proportionate consolidation method. Accordingly, our accompanying condensed consolidated financial statements include our pro rata share of assets, liabilities, revenues and expenses of the limited partnerships in which we participate. Our proportionate share of all significant transactions between us and the limited partnerships has been eliminated.

The accompanying condensed consolidated financial statements have been prepared without audit in accordance with accounting principles generally accepted in the United States of America for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the Securities and Exchange Commission ("SEC"). Accordingly, pursuant to such rules and regulations, certain notes and other financial information included in audited financial statements have been condensed or omitted. In our opinion, the accompanying condensed consolidated financial statements contain all adjustments (consisting of only normal recurring adjustments) necessary to present fairly our financial position, results of operations and cash flows for the periods presented. The results of operations for the six months ended June 30, 2009, and the cash flows for the same period, are not necessarily indicative of the results to be expected for the full year or any other future period.

The accompanying condensed consolidated financial statements should be read in conjunction with our audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2008, as filed with the SEC on February 27, 2009 ("2008 Form 10-K").

Certain prior year amounts have been reclassified to conform to the current year presentation. Such reclassifications are directly related to the presentation of our oil and gas well drilling operations as discontinued operations. The reclassifications had no impact on previously reported net earnings, earnings per share or shareholders' equity. See Note 11 for additional information regarding discontinued operations.

2. RECENT ACCOUNTING STANDARDS

Recently Adopted Accounting Standards

In December 2007, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("FAS") No. 141 (revised 2007), Business Combinations ("FAS No. 141(R)"). FAS No. 141(R) requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their acquisition-date fair values. FAS No. 141(R) also requires disclosure of the information necessary for investors and other users to evaluate and understand the nature and financial effect of the business combination. Additionally, FAS No. 141(R) requires that acquisition-related costs be expensed as incurred. The provisions of FAS No. 141(R) became effective for acquisitions completed on or after January 1, 2009; however, the income tax provisions of FAS No. 141(R) became effective as of that date for all acquisitions, regardless of the acquisition date. FAS No. 141(R) amends FAS No. 109, Accounting for Income Taxes, to require the acquirer to recognize changes in the amount of its deferred tax benefits recognizable due to a business combination either in income from continuing operations in the period of the combination or directly in contributed capital, depending on the circumstances. FAS No. 141(R) further amends FAS No. 109 and FASB Interpretation No. ("FIN") 48, Accounting for Uncertainty in Income Taxes, to require, subsequent to a prescribed measurement period, changes to acquisition-date income tax uncertainties to be reported in income from continuing operations and changes to acquisition-date acquiree deferred tax benefits to be reported in income from continuing operations or directly in contributed capital, depending on the circumstances. In April 2009, the FASB issued FASB Staff Position ("FSP") No. FAS 141(R)-1, Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies ("FSP 141(R)-1"), amending the guidance of FAS No. 141(R) to require that assets acquired and liabilities assumed in a business combination that arise from contingencies be recognized at fair value if fair value can be reasonably estimated and if not, the asset and liability would generally be recognized in accordance with FAS No. 5, Accounting for Contingencies, and FASB Interpretation No. 14, Reasonable Estimation of the Amount of a Loss. Further, FSP 141(R)-1 requires that certain acquired contingencies be treated as contingent consideration and measured both initially and subsequently at fair value. We adopted

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the provisions of FAS No. 141(R) and FSP 141(R)-1 effective January 1, 2009, for which the provisions will be applied prospectively in our accounting for future acquisitions, if any. Upon adoption, we recorded a charge of $1.5 million to general and administrative expense related to acquisition costs deferred at December 31, 2008.

In December 2007, the FASB issued FAS No. 160, Noncontrolling Interests in Consolidated Financial Statements—An Amendment of ARB No. 51 (“FAS No. 160”). FAS No. 160 requires the accounting and reporting for minority interests be recharacterized as noncontrolling interests and classified as a component of equity. Additionally, FAS No. 160 establishes reporting requirements that provide sufficient disclosures which clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. We adopted the provisions of FAS No. 160 effective January 1, 2009. Upon adoption of FAS No. 160, we reclassified our noncontrolling interest in WWWV, LLC from the mezzanine section, between liabilities and equity, of the consolidated balance sheets, to a component of equity, separate from our shareholders’ equity. Net loss attributable to noncontrolling interest for the three and six months ended June 30, 2009 and 2008, was immaterial and was recorded in depreciation, depletion and amortization (“DD&A”) in the accompanying condensed consolidated statements of operations.

In February 2008, the FASB issued FSP No. 157-2, Effective Date of FASB Statement No. 157 (“FAS No. 157”) (“FSP 157-2”), which delayed the effective date of FAS No. 157, Fair Value Measurements, by one year (to January 1, 2009) for nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). Effective January 1, 2009, we adopted the provisions of FAS No. 157 delayed by FSP 157-2. The adoption of FSP 157-2 did not have a material impact on our accompanying condensed consolidated financial statements. See Note 3, Fair Value Measurements.

In March 2008, the FASB issued FAS No. 161, Disclosures about Derivative Instruments and Hedging Activities—An Amendment of FASB Statement No. 133, which changes the disclosure requirements for derivative instruments and hedging activities. Enhanced disclosures are required to provide information about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations and (c) how derivative instruments and related hedged items affect an entity’s financial position, financial performance and cash flows. We adopted the provisions of FAS No. 161 effective January 1, 2009. The adoption of FAS No. 161 did not have a material impact on our accompanying condensed consolidated financial statements. See Note 4, Derivative Financial Instruments.

In May 2009, the FASB issued FAS No. 165, Subsequent Events (“FAS No. 165”). FAS No. 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued. Specifically, FAS No. 165 sets forth the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements, and the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. FAS No. 165 is effective for interim or annual periods ending after June 15, 2009, and is applied prospectively. We adopted FAS No. 165 as of June 30, 2009. We have evaluated our activities subsequent to June 30, 2009, through August 10, 2009 (the date the financial statements were issued), and have concluded that no subsequent events have occurred that would require recognition in the financial statements or disclosure in the notes to the financial statements.

Recently Issued Accounting Standards

In January 2009, the SEC published its final rule, Modernization of Oil and Gas Reporting, which modifies the SEC’s reporting and disclosure rules for oil and natural gas reserves. The most notable changes of the final rule include the replacement of the single day period-end pricing to value oil and natural gas reserves to a 12-month average of the first day of the month price for each month within the reporting period. The final rule also permits voluntary disclosure of probable and possible reserves, a disclosure previously prohibited by SEC rules. The revised reporting and disclosure requirements are effective for our Form 10-K for the year ending December 31, 2009. Early adoption is not permitted. We are evaluating the impact that adoption of this final rule will have on our consolidated financial statements, related disclosure and management's discussion and analysis.

In June 2009, the FASB issued FAS No. 167, Amendments to FASB Interpretation No. 46(R), to improve financial reporting by enterprises involved with variable interest entities by addressing (1) the effects on certain provisions of FIN 46 (revised December 2003) ("FIN 46(R)"), Consolidation of Variable Interest Entities, as a result of the elimination of the qualifying special-purpose entity concept in FAS No. 166, Accounting for Transfers of Financial Assets, and (2) constituent concerns about the application of certain key provisions of FIN 46(R), including those in which the accounting and disclosures under the Interpretation do not always provide timely and useful information about an enterprise's involvement in a variable interest entity. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2009, with earlier adoption prohibited. We are evaluating the impact that the adoption of FAS No. 167 will have on our consolidated financial statements, related disclosure and management's discussion and analysis.

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In June 2009, the FASB issued FAS No. 168, The FASB Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles. This standard replaces FAS No. 162, The Hierarchy of Generally Accepted Accounting Principles, and establishes only two levels of U.S. GAAP, authoritative and nonauthoritative. The FASB Accounting Standards Codification (the "Codification") will become the source of authoritative, nongovernmental U.S. generally accepted accounting principles ("GAAP"), except for rules and interpretive releases of the SEC, which are sources of authoritative GAAP for SEC registrants. All other nongrandfathered, non-SEC accounting literature not included in the Codification will become nonauthoritative. This standard is effective for financial statements issued for fiscal years and interim periods ending after September 15, 2009. As the Codification was not intended to change or alter existing GAAP, we do not expect the adoption to have any impact on our consolidated financial statements.

3. FAIR VALUE MEASUREMENTS

Determination of Fair Value. We determine the fair value of our assets and liabilities, unless specifically excluded, pursuant to FAS No. 157. FAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

FAS No. 157 establishes a fair value hierarchy that requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability, and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels. The three levels of inputs that may be used to measure fair value are defined as:

Level 1 – Quoted prices (unadjusted) in active markets for identical assets or liabilities. Included in Level 1 are our commodity derivative instruments for New York Mercantile Exchange ("NYMEX")-based natural gas swaps.

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including (i) quoted prices for similar assets or liabilities in active markets, (ii) quoted prices for identical or similar assets or liabilities in inactive markets, (iii) inputs other than quoted prices that are observable for the asset or liability and (iv) inputs that are derived from observable market data by correlation or other means.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Included in Level 3 are our asset retirement obligations and our commodity derivative instruments for Colorado Interstate Gas ("CIG") and Panhandle Eastern Pipeline ("PEPL")-based natural gas swaps, oil swaps, oil and natural gas options, and physical sales and purchases and our natural gas basis protection derivative instruments.

Derivative Financial Instruments. We measure the fair value of our derivative instruments based upon quoted market prices, where available. Our valuation determination includes: (1) identification of the inputs to the fair value methodology through the review of counterparty statements and other supporting documentation, (2) determination of the validity of the source of the inputs, (3) corroboration of the original source of inputs through access to multiple quotes, if available, or other information and (4) monitoring changes in valuation methods and assumptions. The methods described above may produce a fair value calculation that may not be indicative of future fair values. Our valuation determination also gives consideration to nonperformance risk on our own liabilities as well as the credit standing of our counterparties. We primarily use two financial institutions as counterparties to our derivative contracts, with two of them holding the majority of our derivative assets. We have evaluated the credit risk of the counterparties holding our derivative assets using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant. As of June 30, 2009, no valuation allowance was recorded. Furthermore, while we believe these valuation methods are appropriate and consistent with those used by other market participants, the use of different methodologies, or assumptions, to determine the fair value of certain financial instruments could result in a different estimate of fair value.

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The following table presents, by hierarchy level, our derivative financial instruments, including both current and non-current portions, measured at fair value as of December 31, 2008, and June 30, 2009:

	Level 1	Level 3	Total
		(in thousands)	
As of December 31, 2008			
Assets:			
Commodity based derivatives	$ 19,359	$ 144,644	$ 164,003
Basis protection derivative contracts	-	33	33
Total assets	19,359	144,677	164,036
Liabilities:			
Commodity based derivatives	(658)	(5,490)	(6,148)
Basis protection derivative contracts	-	(4,338)	(4,338)
Total liabilities	(658)	(9,828)	(10,486)
Net assets	$ 18,701	$ 134,849	$ 153,550
As of June 30, 2009			
Assets:			
Commodity based derivatives	$ 16,842	$ 94,833	$ 111,675
Basis protection derivative contracts	-	134	134
Total assets	16,842	94,967	111,809
Liabilities:			
Commodity based derivatives	(4,175)	(4,857)	(9,032)
Basis protection derivative contracts	-	(37,491)	(37,491)
Total liabilities	(4,175)	(42,348)	(46,523)
Net assets	$ 12,667	$ 52,619	$ 65,286

The following table presents the changes in our Level 3 derivative financial instruments measured on a recurring basis:

	(in thousands)
Fair value, net asset, as of December 31, 2008	$ 134,849
Changes in fair value included in statement of operations line item:	
Oil and gas price risk management gain, net	(3,306)
Sales from natural gas marketing	(34)
Cost of natural gas marketing	848
Changes in fair value included in balance sheet line item (1):	
Accounts receivable - affiliates	(11,402)
Accounts payable - affiliates	(14,524)
Settlements	
Oil and gas sales	(53,838)
Natural gas marketing	26
Fair value, net asset, as of June 30, 2009	$ 52,619
Changes in unrealized gains (losses) relating to assets (liabilities) still held as of June 30, 2009, included in statement of operations line item:	
Oil and gas price risk management gain, net	$ (14,561)
Sales from natural gas marketing	191
Cost of natural gas marketing	(1,979)

$	(16,349)

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(1) Represents the change in fair value related to derivative instruments entered into by us and allocated to our affiliated partnerships.

See Note 4, Derivative Financial Instruments, for additional disclosure related to our derivative financial instruments.

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Non-Derivative Assets and Liabilities. The carrying values of the financial instruments comprising cash and cash equivalents, restricted cash, accounts receivable and accounts payable approximate fair value due to the short-term maturities of these instruments.

We assess our oil and gas properties for possible impairment, upon a triggering event, by comparing net capitalized costs to estimated undiscounted future net cash flows on a field-by-field basis using estimated production based upon prices at which we reasonably estimate the commodity to be sold. The estimates of future prices may differ from current market prices of oil and natural gas. Certain events, including but not limited to, downward revisions in estimates to our reserve quantities, expectations of falling commodity prices or rising operating costs, could result in a triggering event and, therefore, a possible impairment of our oil and gas properties. If net capitalized costs exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value utilizing a future discounted cash flows analysis and is measured by the amount by which the net capitalized costs exceed their fair value. During the six months ended June 30, 2009, there were no triggering events; therefore, no impairment of oil and gas properties was recognized.

The portion of our long-term debt related to our credit facility approximates fair value due to the variable nature of its related interest rate. We estimate the fair value of the portion of our long-term debt related to our senior notes to be approximately $167 million or approximately 82.25% of par value as of June 30, 2009. We determined this valuation based upon measurements of trading activity and quotes provided by brokers and traders participating in the trading of the securities.

We account for asset retirement obligations by recording the estimated fair value of our plugging and abandonment obligations when incurred, which is when the well is completely drilled. We estimate the fair value of our plugging and abandonment obligations based on a discounted cash flows analysis. Upon initial recognition of an asset retirement obligation, we increase the carrying amount of the long-lived asset by the same amount as the liability. Over time, the liabilities are accreted for the change in their present value, through charges to oil and gas production and well operations costs. The initial capitalized costs are depleted based on the useful lives of the related assets, through charges to DD&A. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. Revisions in estimated liabilities can result from revisions of estimated inflation rates, escalating retirement costs and changes in the estimated timing of settling asset retirement obligations. See Note 7, Asset Retirement Obligations, for a reconciliation of changes in our asset retirement obligation for the six months ended June 30, 2009.

4. DERIVATIVE FINANCIAL INSTRUMENTS

We are exposed to the effect of market fluctuations in the prices of oil and natural gas. Price risk represents the potential risk of loss from adverse changes in the market price of oil and natural gas commodities. We employ established policies and procedures to manage the risks associated with these market fluctuations using commodity derivative instruments. Our policy prohibits the use of oil and natural gas derivative instruments for speculative purposes.

We have elected not to designate any of our derivative instruments as hedges. Accordingly, we recognize all of our derivative instruments as either assets or liabilities on our accompanying condensed consolidated balance sheets at fair value. Changes in the fair value of those derivative instruments allocated to us are recorded in our accompanying condensed consolidated statements of operations, and changes in the fair value of those derivative instruments allocated to our affiliated partnerships are recorded in accounts payable - affiliates and accounts receivable - affiliates in our accompanying condensed consolidated balance sheets. Changes in the fair value of derivative instruments allocated to us and related to oil and gas sales are recorded in oil and gas price risk management, net and changes in fair value of derivatives related to natural gas marketing are recorded in sales from and cost of natural gas marketing.

Included in the fair value of our derivative assets and liabilities on our accompanying condensed consolidated balance sheets are the portion of derivative instruments entered into by us and allocated to our affiliated partnerships, as well as a corresponding offsetting payable to and receivable from the partnerships, respectively. As positions allocated to our affiliated partnerships settle, the realized gains and losses are netted for distribution. Net realized gains are paid to the partnerships and net realized losses are deducted from the partnerships' oil and gas cash available for distribution. The affiliated partnerships bear their allocated share of counterparty risk.

Validation of a contract's fair value is performed internally and while we use common industry practices to develop our valuation techniques, changes in our pricing methodologies or the underlying assumptions could result in significantly different fair values. See Note 3, Fair Value Measurements, for a discussion of how we fair value our derivative instruments.

As of June 30, 2009, we had derivative instruments in place for a portion of our anticipated production through 2012 for a total of 35,582,339 MMbtu of natural gas and 845,376 Bbls of crude oil.

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Derivative Strategies. Our results of operations and operating cash flows are affected by changes in market prices for oil and natural gas. To mitigate a portion of our exposure to adverse market changes, we have entered into various derivative contracts.

- For our oil and gas sales, we enter into, for our own and affiliated partnerships' production, derivative contracts to protect against price declines in future periods. While we structure these derivatives to reduce our exposure to changes in price associated with the derivative commodity, they also limit the benefit we might otherwise have received from price increases in the physical market.

- For our natural gas marketing, we enter into fixed-price physical purchase and sale agreements that qualify as derivative contracts. In order to offset the fixed-price physical derivatives in our natural gas marketing, we enter into financial derivative instruments that have the effect of locking in the prices we will receive or pay for the same volumes and period, offsetting the physical derivative.

We believe our derivative instruments continue to be effective in achieving the risk management objectives for which they were intended.

As of June 30, 2009, our derivative instruments were comprised of commodity collars and swaps, basis protection swaps and physical sales and purchases.

- Collars contain a fixed floor price (put) and ceiling price (call). If the market price falls below the fixed put strike price, we receive the market price from the purchaser and receive the difference between the put strike price and market price from the counterparty. If the market price exceeds the fixed call strike price, we receive the market price from the purchaser and pay the difference between the call strike price and market price to the counterparty. If the market price is between the put and call strike price, no payments are due to or from the counterparty.

- Swaps are arrangements that guarantee a fixed price. If the market price is below the fixed contract price, we receive the market price from the purchaser and receive the difference between the market price and the fixed contract price from the counterparty. If the market price is above the fixed contract price, we receive the market price from the purchaser and pay the difference between the market price and the fixed contract price to the counterparty.

- Basis protection swaps are arrangements that guarantee a price differential for natural gas from a specified delivery point. For CIG basis protection swaps, which have negative differentials to NYMEX, we receive a payment from the counterparty if the price differential is greater than the stated terms of the contract and pay the counterparty if the price differential is less than the stated terms of the contract.

- Physical sales and purchases are derivatives for fixed-priced physical transactions where we sell or purchase third party supply at fixed rates. These physical derivatives are offset by financial swaps: for a physical sale the offset is a swap purchase and for a physical purchase the offset is a swap sale.

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Our derivative instruments are recorded at fair value. The following table summarizes the location and fair value amounts of our derivative instruments in the accompanying condensed consolidated balance sheets as of June 30, 2009, and December 31, 2008.

Derivatives instruments not designated as hedges (1):		Balance sheet line item	Fair Value June 30, 2009	Fair Value December 31, 2008
			(in thousands)	
Derivative Assets:	Current			
	Commodity contracts			
	Related to oil and gas sales	Fair value of derivatives	$ 94,001	$ 112,036
	Related to natural gas marketing	Fair value of derivatives	3,748	4,820
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	132	25
			97,881	116,881
	Non Current			
	Commodity contracts			
	Related to oil and gas sales	Fair value of derivatives	12,947	45,971
	Related to natural gas marketing	Fair value of derivatives	979	1,176
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	2	8
			13,928	47,155
Total Derivative Assets			$ 111,809	$ 164,036
Derivative Liabilities:	Current			
	Commodity contracts			
	Related to oil and gas sales activities	Fair value of derivatives	$ (697)	$ -
	Related to natural gas marketing	Fair value of derivatives	(4,210)	(4,720)
	Basis protection contracts			
	Related to oil and gas sales activities	Fair value of derivatives	(3,379)	-
	Related to natural gas marketing	Fair value of derivatives	(39)	(46)
			(8,325)	(4,766)
	Non Current			
	Commodity contracts			
	Related to oil and gas sales	Fair value of derivatives	(3,108)	-
	Related to natural gas marketing	Fair value of derivatives	(1,017)	(1,428)
	Basis protection contracts			

	Related to oil and gas sales	Fair value of derivatives		(34,073	)		(4,292	)
				(38,198	)		(5,720	)
Total Derivative Liabilities			$	(46,523	)	$	(10,486	)

(1) As of June 30, 2009, and December 31, 2008, none of our derivative instruments were designated as hedges.

In addition to including the assets and liabilities related to our share of oil and gas production, the above table and our accompanying condensed consolidated balance sheets include the assets and liabilities related to derivative contracts we entered into and those that we allocate to our affiliated partnerships as the managing general partner. For those derivative contracts which we have allocated to the affiliated partnerships, we have on our accompanying condensed consolidated balance sheets a corresponding payable to and receivable from the partnerships of $22.7 million and $14.3 million, respectively, as of June 30, 2009, and $37.5 million and $1.6 million, respectively, as of December 31, 2008.

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The following table summarizes the impact of our derivative instruments on our accompanying condensed consolidated statements of operations for the three and six months ended June 30, 2009 and 2008.

	Three Months Ended June 30,					
	2009			2008		
Statement of operations line item	Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	Realized and Unrealized Gains (Losses) For the Current Period	Total	Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	Realized and Unrealized Gains (Losses) For the Current Period	Total
	(in thousands)					
Oil and gas price risk management gain (loss), net (1)						
Realized gains (losses)	$ 25,699	$ (1,404)	$ 24,295	$ (9,690)	$ (5,664)	$ (15,354)
Unrealized gains (losses)	(25,699)	(21,880)	(47,579)	9,690	(96,134)	(86,444)
Total oil and gas price risk management gain (loss), net (1)	$ -	$ (23,284)	$ (23,284)	$ -	$ (101,798)	$ (101,798)
Sales from natural gas marketing(2)						
Realized gains (losses)	$ 2,055	$ (191)	$ 1,864	$ (1,391)	$ (892)	$ (2,283)
Unrealized gains (losses)	(2,055)	99	(1,956)	1,391	(10,444)	(9,053)
Total sales from natural gas marketing(2)	$ -	$ (92)	$ (92)	$ -	$ (11,336)	$ (11,336)
Cost of natural gas marketing(2)						
Realized gains (losses)	$ (1,996)	$ 1,750	$ (246)	$ 1,688	$ (1,637)	$ 51
Unrealized gains (losses)	1,996	(35)	1,961	(1,688)	10,862	9,174
Total cost of natural gas marketing(2)	$ -	$ 1,715	$ 1,715	$ -	$ 9,225	$ 9,225

	Six Months Ended June 30,					
	2009			2008		
Statement of operations line item	Reclassification of Realized Gains (Losses) Included in	Realized and Unrealized Gains (Losses)	Total	Reclassification of Realized Gains (Losses)	Realized and Unrealized Gains (Losses)	Total

	Prior Periods Unrealized	For the Current Period		Included in Prior Periods Unrealized	For the Current Period	
			(in thousands)			
Oil and gas price risk management gain (loss), net (1)						
Realized gains (losses)	$ 47,587	$ 13,334	$ 60,921	$ (704)	$ (17,061)	$ (17,765)
Unrealized gains (losses)	(47,587)	(12,935)	(60,522)	704	(127,047)	(126,343)
Total oil and gas price risk management gain (loss), net (1)	$ -	$ 399	$ 399	$ -	$ (144,108)	$ (144,108)
Sales from natural gas marketing(2)						
Realized gains (losses)	$ 3,344	$ 888	$ 4,232	$ 1,244	$ (3,041)	$ (1,797)
Unrealized gains (losses)	(3,344)	2,213	(1,131)	(1,244)	(15,447)	(16,691)
Total sales from natural gas marketing(2)	$ -	$ 3,101	$ 3,101	$ -	$ (18,488)	$ (18,488)
Cost of natural gas marketing(2)						
Realized gains (losses)	$ (3,148)	$ 2,595	$ (553)	$ (835)	$ 952	$ 117
Unrealized gains (losses)	3,148	(2,257)	891	835	16,543	17,378
Total cost of natural gas marketing(2)	$ -	$ 338	$ 338	$ -	$ 17,495	$ 17,495

(1) Represents realized and unrealized gains and losses on derivative instruments related to our oil and gas sales.
(2) Includes realized and unrealized gains and losses on derivative instruments related to our natural gas marketing.

Concentration of Credit Risk. A significant portion of our liquidity is concentrated in derivative instruments that enable us to manage a portion of our exposure to price volatility from producing oil and natural gas. These arrangements expose us to credit risk of nonperformance by our counterparties. We primarily use two financial institutions, who are also major lenders in our credit facility agreement, as counterparties to our derivative contracts.

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As of June 30, 2009, the following counterparties expose us to credit risk.

Counterparty Name	Fair Value of Derivative Assets June 30, 2009 (in thousands)
JPMorgan Chase Bank, N.A. (1)	$ 51,092
BNP Paribas (1)	59,563
Various (2)	1,154
Total	$ 111,809

(1) Major lender in our credit facility, see Note 6.
(2) Represents a total of 32 counterparties, includes five lenders in our credit facility.

5. PROPERTIES AND EQUIPMENT

	June 30, 2009	December 31, 2008
	(in thousands)	
Properties and equipment, net:		
Oil and gas properties (successful efforts method of accounting)		
Proved	$ 1,306,475	$ 1,245,316
Unproved	32,162	32,768
Total oil and gas properties	1,338,637	1,278,084
Pipelines and related facilities	37,746	34,067
Transportation and other equipment	33,003	31,693
Land and buildings	14,414	14,570
Construction in progress	438	275
	1,424,238	1,358,689
Accumulated DD&A	(393,363)	(325,611)
	$ 1,030,875	$ 1,033,078

Suspended Well Costs.

The following table identifies the capitalized exploratory well costs that are pending determination of proved reserves and are included in properties and equipment in our accompanying condensed consolidated balance sheets.

	Amount (in thousands)	Number of Wells
Beginning balance at December 31, 2008	$ 1,180	6
	5,716	4

Additions to capitalized exploratory well costs pending the determination of proved reserves						
Reclassifications to wells, facilities and equipment based on the determination of proved reserves		(3,701	)		(5	)
Capitalized exploratory well costs charged to expense		(318	)		(2	)
Ending balance at June 30, 2009	$	2,877			3	

As of June 30, 2009, none of the three suspended wells awaiting the determination of proved reserves have been capitalized for a period greater than one year after the completion of drilling.

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6. LONG-TERM DEBT

Long-term debt consists of the following:

	June 30, 2009	December 31, 2008
	(in thousands)	
Credit facility	$ 218,000	$ 194,500
12% Senior notes due 2018, net of discount of $2.5 million	200,512	200,367
Total long-term debt	$ 418,512	$ 394,867

Credit facility

We have a credit facility co-arranged by JPMorgan Chase Bank, N.A. ("JPMorgan") and BNP Paribas, as amended last on May 22, 2009 ("the Sixth Amendment"), dated as of November 4, 2005, with an aggregate revolving commitment of $350 million. The credit facility, through a series of amendments, includes commitments from: Bank of America, N.A.; Calyon New York Branch; Bank of Montreal; Wachovia Bank, N.A.; Guaranty Bank, FSB; The Royal Bank of Scotland plc; Bank of Oklahoma; Compass Bank; and The Bank of Nova Scotia. The maximum allowable commitment under the current credit facility is $500 million. The credit facility is subject to and secured by required levels of oil and natural gas reserves. The credit facility requires an aggregated security of a value no less than 80% of the value of the direct interests included in the borrowing base properties. Our credit facility borrowing base is subject to size redeterminations each April and October based upon a quantification of our reserves at December 31st and June 30th, respectively; additionally, we or our lenders may request a redetermination upon the occurrence of certain events. A commodity price deck reflective of the current and future commodity pricing environment, as agreed upon by us and our lenders, is utilized to quantify our reserve reports and determine the underlying borrowing base. As of June 30, 2009, our aggregate revolving commitment was secured by substantially all of our oil and gas properties.

We are required to pay a commitment fee of .5% per annum on the unused portion of the activated credit facility. Interest accrues at an alternative base rate ("ABR") or adjusted LIBOR at our discretion. The ABR is the greater of JPMorgan's prime rate, a secondary market rate of a three-month certificate of deposit plus 1%, one month LIBOR plus 1% or the federal funds effective rate plus .5%. ABR and adjusted LIBOR borrowings are assessed an additional margin spread based upon the outstanding balance as a percentage of the available balance. ABR borrowings are assessed an additional margin of 1.375% to 2.375%. Adjusted LIBOR borrowings are assessed an additional margin spread of 2.25% to 3.25%. Pursuant to the Sixth Amendment, we paid $8.9 million in debt issuance costs in May 2009; these costs were capitalized and will be amortized using the effective interest rate method over the three-year term of the credit facility, or approximately $0.9 million per quarter. No principal payments are required until the credit agreement expires on May 22, 2012, or in the event that the borrowing base would fall below the outstanding balance.

The credit facility contains covenants customary for agreements of this type, including, but not limited to, limitations on our ability to: (a) incur additional indebtedness and guarantees, (b) create liens and other encumbrances on our assets, (c) consolidate, merge or sell assets, (d) pay dividends and other distributions, (e) make certain investments, loans and advances, (f) enter into sale/leaseback transactions, and (g) engage in hedging activities unless certain requirements are satisfied. The credit facility also requires us to execute and deliver specified mortgages and other evidences of security and to deliver specified opinions of counsel and other evidences of title. Further, we are required to comply with certain financial tests and maintain certain financial ratios. The financial tests and ratios include requirements to: (a) maintain a minimum ratio of consolidated current assets to consolidated current liabilities, or current ratio, as defined, of 1.00 to 1.00 and (b) not to exceed a maximum leverage ratio of 4.25 to 1.00 through December 31, 2010, 4.00 to 1.00 through June 30, 2011, and 3.75 to 1.00 thereafter.

As of June 30, 2009, we had drawn $218 million from our credit facility compared to $194.5 million as of December 31, 2008. The borrowing rate on the outstanding balance was 3.8% as of June 30, 2009, compared to 4.6% as of December 31, 2008. We were in compliance with all covenants at June 30, 2009, and expect to remain in compliance throughout the next year.

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12% Senior Notes Due 2018

Our outstanding 12% senior notes were issued on February 8, 2008. The principal amount of the senior notes is $203 million, which is payable at maturity on February 15, 2018. Interest is payable in cash semi-annually in arrears on each February 15 and August 15. The senior notes were issued at a price of 98.572% of the principal amount. In addition, $5.4 million in costs associated with the issuance of the debt has been capitalized as a deferred loan cost. The original discount and the deferred note costs are being amortized to interest expense over the term of the debt using the effective interest method.

The indenture governing the notes contains customary representations and warranties as well as typical restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (a) incur additional debt, (b) make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) pay dividends or other payments by restricted subsidiaries, (e) create liens that secure debt, (f) enter into transactions with affiliates, and (g) merge or consolidate with another company. Additionally, we are subject to two incurrence covenants: 1) earnings before interest, taxes, depreciation, amortization and capital expenditures (“EBITDAX”) of at least two times interest expense and 2) total debt of less than 4.0 times EBITDAX. We were in compliance with all covenants as of June 30, 2009, and expect to remain in compliance throughout the next year.

The notes are senior unsecured obligations and rank, in right of payment, equally with all of our existing and future senior unsecured indebtedness and senior to any of our existing and future subordinated indebtedness. The notes are effectively subordinated to any of our existing or future secured indebtedness to the extent of the assets securing such indebtedness.

The notes are not initially guaranteed by any of our subsidiaries. However, subsidiaries may be obligated to guarantee the notes if:

- a subsidiary is a guarantor under our senior credit facility; and
- the subsidiary has consolidated tangible assets that constitute 10% or more of our consolidated tangible assets.

Subject to specified exceptions, any subsidiary guarantor will be restricted from entering into certain transactions including the disposition of all or substantially all of its assets or merging with or into another entity. Subsidiary guarantors may be released from a guarantee under circumstances specified in the indenture. As of June 30, 2009, none of our subsidiaries were obligated as guarantors of our senior notes.

The indenture provides that at any time, which may be more than once, before February 15, 2011, we may redeem up to 35% of the outstanding notes with proceeds from one or more equity offerings at a redemption price of 112% of the principal amount of the notes redeemed, plus accrued and unpaid interest, as long as:

- at least 65% of the aggregate principal amount of the notes issued on February 8, 2008, remains outstanding after each such redemption; and
- the redemption occurs within 180 days after the closing of the equity offering.

The notes also provide that we may, at our option, redeem all or part of the notes, at any time prior to February 15, 2013, at the make-whole price set forth in the indenture, and on or after February 15, 2013, at fixed redemption prices, plus accrued and unpaid interest, if any, to the date of redemption. Further, the indenture provides that upon a change of control, we must give holders of the notes the opportunity to put their notes to us for repurchase at a repurchase price of 101% of the principal amount, plus accrued and unpaid interest.

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7. ASSET RETIREMENT OBLIGATIONS

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

	Amount (in thousands)
Beginning balance at December 31, 2008	$ 23,086
Obligations assumed with development activities and acquisitions	686
Accretion expense	695
Obligations discharged with disposal of properties and asset retirements	(26)
Ending balance at June 30, 2009	$ 24,441

Approximately $0.1 million of the asset retirement obligations was classified as short-term and included in other accrued expenses as of June 30, 2009, and December 31, 2008.

8. COMMITMENTS AND CONTINGENCIES

Drilling and Development Agreements. In connection with the acquisition of oil and gas properties in October 2007 from an unaffiliated party, we are obligated to drill 100 wells on the acquired acreage in Pennsylvania by January 2016. We will retain a majority interest in each well drilled. For each well we fail to drill, we are obligated to pay to the seller liquidated damages of $25,000 per undrilled well for a total contingent obligation of $2.5 million or reassign to the seller the interest acquired in the number of undrilled well locations. As of June 30, 2009, we have drilled 28 wells pursuant to this agreement.

We have entered into contracts that provide firm transportation, sales and processing charges on pipeline systems through which we transport or sell our natural gas and the natural gas of other companies, working interest owners and our affiliated partnerships. These contracts require us to pay these transportation and processing charges whether the required volumes are delivered or not.

The following table sets forth gross volume information about long-term firm sales, processing and transportation agreements for pipeline capacity, which require a demand charge whether volumes are delivered or not. We record in our financial statements only our share of costs based upon our working and net revenue interest in the wells. If the volumes below are not met, we will bear all costs related to the volume shortfall.

Type of Arrangement	Location	Average Annual Volume (MMbtu)	Expiration Date
Firm sales and processing	Grand Valley	22,454,000	May 2021
Firm transportation	NECO Area	1,825,000	December 2010
Firm transportation	NECO Area	1,825,000	December 2016
		10,615,000	

Firm transportation (1)	Appalachian Basin	December 2022

(1) Contract is a precedent agreement and becomes effective when the planned pipeline is placed in service, estimated at this time to be 2012. Contract is null and void if pipeline is not completed.

In September 2008, we entered into a pipeline and processing plants expansion agreement with an unrelated party, who is currently the purchaser of the majority of our Wattenberg Field natural gas production. Pursuant to the agreement, we agreed to make a capital investment of $60 million, for our own benefit, over a three-year period commencing on January 1, 2009, to develop or facilitate production in our Wattenberg Field dedicated to this purchaser and, if the purchaser failed to diligently proceed with the pipeline and processing plants, we would be relieved of our obligations under the agreement. In March 2009, we received from the unrelated party a notice waiving our commitment and stating that the pipeline and processing plant expansions were either on hold or had been delayed. The waiver relieves us of the $60 million capital investment obligation.

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Drilling Rig Contracts. In order to secure the services for drilling rigs, we have commitments for the use of two drilling rigs with a drilling contractor. The commitments call for a minimum commitment of $12,500 daily for a specified amount of time if we cease to use the drilling rigs and a maximum commitment of $40,680 daily for a specified amount of time for daily use of the drilling rigs. One of the commitments expires in August 2009 and the other in July 2010. In January 2009, based on our decision to temporarily cease drilling operations in the Piceance Basin, we demobilized one of these rigs. As of June 30, 2009, we have an outstanding minimum commitment for $2 million and an outstanding maximum commitment for $8.7 million, which includes $1.4 million related to a rig sublet to a third party and remains our obligation should the third party default on terms of the sublet agreement.

Litigation.

We are involved in various legal proceedings that we consider normal to our business. Although the results cannot be known with certainty, we believe that we have properly accrued reserves.

Colorado Royalty. 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 we underpaid royalties on natural gas produced from wells operated by us in parts of the State of Colorado (the “Droegemueller Action”). The plaintiff sought declaratory relief and to recover an unspecified amount of compensation for underpayment of royalties paid by us pursuant to leases. We removed the case to Federal Court on June 28, 2007. On October 10, 2008, the court preliminarily approved a settlement agreement between the plaintiffs and the Company, on behalf of itself and the partnerships for which the Company is the managing general partner. Based on the settlement terms, the settlement amount payable by the Company is $5.8 million. Such moneys, in addition to moneys related to the settlement on behalf of the partnerships for which the Company is the managing general partner, were deposited in an escrow account on November 3, 2008. We have accrued through June 30, 2009, and included in other accrued expenses in our accompanying condensed consolidated balance sheets, a related $5.8 million litigation reserve. The final settlement was approved by the court on April 7, 2009. Settlement distribution checks were mailed in July 2009.

West Virginia Royalty. On January 21, 2009, a lawsuit was filed in West Virginia state court in Barbour County, styled Beymer v. Petroleum Development Corporation and Riley National Gas Company, CA No. 09-C-3 (“Beymer lawsuit”), alleging a class action on behalf of lessors for failure to properly pay royalties. The allegations state that the Company improperly deducted certain charges and costs before applying the royalty percentage. Punitive damages are requested in addition to breach of contract, tort, and fraud allegations. On January 27, 2009, another suit was filed in West Virginia state court in Harrison County, styled Gobel v. Petroleum Development Corporation, CA No. 09-C-40, alleging a class action with allegations similar to those alleged in the Beymer lawsuit. Both cases have been removed to federal court in the Northern District of West Virginia. In late April 2009, the federal judges for the respective cases approved jointly filed motions and stipulations providing for, among other things, a 180 day stay to explore settlement opportunities.

Colorado Stormwater Permit. On December 8, 2008, we received a Notice of Violation/Cease and Desist Order (the “Notice”) from the Colorado Department of Public Health and Environment, related to the stormwater permit for the Garden Gulch Road. The Company manages this private road for Garden Gulch LLC. The Company is one of eight users of this road, all of which are oil and gas companies operating in the Piceance region of Colorado. Operating expenses, including this fine, if any, are allocated among the eight users of the road based upon their respective usage. The Notice alleges a deficient and/or incomplete stormwater management plan, failure to implement best management practices and failure to conduct required permit inspections. The Notice requires corrective action and states that the recipient shall cease and desist such alleged violations. The Notice states that a violation could result in civil penalties up to $10,000 per day. The Company’s responses were submitted on February 6, 2009, and April 8, 2009. No civil penalties have been imposed or requested at this time. Given the preliminary stage of this proceeding and the inherent uncertainty in administrative actions of this nature, the Company is unable to predict the ultimate outcome of this administrative action at this time.

We are involved in various other legal proceedings that we consider normal to our business. Although the results cannot be known with certainty, we believe that the ultimate results of such proceedings will not have a material adverse effect on our financial position, results of operations or liquidity.

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Partnership Repurchase Provision. Substantially all of our drilling programs contain a repurchase provision where investing partners may request that we purchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that we are 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, subject to our financial ability to do so. As of June 30, 2009, the maximum annual repurchase obligation, based upon the minimum price described above, was approximately $15.1 million. We believe we have adequate liquidity to meet this obligation. For the six months ended June 30, 2009, we paid $1.3 million under this provision for the purchase of partnership units.

Employment Agreements with Executive Officers. We have employment agreements with our Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer and other executive officers. The employment agreements provide for annual base salaries, eligibility for performance bonus compensation, and other various benefits, including retirement and termination benefits.

In the event of termination following a change of control of the Company, or where the Company terminates the executive officer without cause or where an executive officer terminates employment for good reason, the severance benefits range from two times to three times the sum of his highest annual base salary during the previous two years of employment immediately preceding the termination date and his highest annual bonus received during the same two year period. For this purpose a “change of control” corresponds to the definition of “change of control” under Section 409A of the Internal Revenue Code of 1986 (IRC) and the supporting treasury regulations. The executive officer is also entitled to (i) vesting of any unvested equity compensation (excluding all long-term incentive performance shares), (ii) reimbursement for any unpaid expenses, (iii) retirement benefits earned under the current and/or previous agreements, (iv) continued coverage under our medical plan for up to 18 months, and (v) payment of any earned and unpaid bonus amounts. In addition, the executive officer is entitled to receive any benefits that he would have otherwise been entitled to receive under our 401(k) and profit sharing plan, although those benefits are not increased or accelerated.

In the event that an executive officer is terminated for just cause, we are required to pay the executive officer his base salary through the termination date plus any bonus (only for periods completed and accrued, but not paid), incentive, deferred, retirement or other compensation, and to provide any other benefits, which have been earned or become payable as of the termination date but which have not yet been paid or provided.

In the event that an executive officer voluntarily terminates his employment for other than good reason, he is entitled to receive (i) his base salary, bonus and incremental retirement payment prorated for the portion of the year that the executive officer is employed by the Company, provided, however, that with respect to the bonus, for certain executive officers, there shall be no proration of the bonus if such executive leaves prior to the last day of the year and, with respect to the remaining executive officers, there shall be no proration of the bonus in the event such executive officer leaves prior to March 31 in the year of his termination, (ii) any incentive, deferred or other compensation which has been earned or has become payable, but which has not yet been paid under the schedule originally contemplated in the agreement under which they were granted, (iii) any unpaid expense reimbursement upon presentation by the executive officer of an accounting of such expenses in accordance with our normal practices, and (iv) any other payments for benefits earned under the employment agreement or our plans.

In the event of death or disability, the executive is entitled to receive certain benefits. For this purpose, the definition of “disability” corresponds to the definition under IRC 409A and the supporting treasury regulations. The benefits shall be payable in a lump sum and shall be equal to the compensation and other benefits that would otherwise have been paid for a six month period following the termination date plus a pro-rated portion of the performance bonus.

Derivative Contracts. We would be exposed to oil and natural gas price fluctuations on underlying purchase and sale contracts should the counterparties to our derivative instruments or the counterparties to our gas marketing contracts not perform. Nonperformance is not anticipated. We have had no counterparty default losses.

Partnership Casualty Losses. As Managing General Partner of 33 partnerships, we have liability for any potential casualty losses in excess of the partnership assets and insurance. We believe the casualty insurance coverage that we and our subcontractors carry is adequate to meet this potential liability.

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9. STOCK-BASED COMPENSATION

We maintain equity compensation plans for officers, certain key employees and non-employee directors. In accordance with the plans, awards may be issued in the form of stock options, stock appreciation rights, restricted stock, performance shares and performance units. Through the date of this report, we have not issued any stock appreciation rights or performance units.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009 (1)(2)	2008	2009 (1)(3)	2008 (4)
	(in thousands)			
Total stock-based compensation expense	$ 2,345	$ 1,154	$ 3,984	$ 2,946
Income tax benefit	(895)	(433)	(1,520)	(1,124)
Net income impact	$ 1,450	$ 721	$ 2,464	$ 1,822

(1)Includes $0.8 million related to a separation agreement with a former executive vice president.
(2)Includes $0.2 million related to an agreement with our former chief executive officer.
(3)Includes $0.5 million related to an agreement with our former chief executive officer.
(4)Includes $1.1 million related to a separation agreement with our former president.

Stock Option Awards. We have granted stock options pursuant to various stock compensation plans. Outstanding options expire ten years from the date of grant and become exercisable ratably over a four year period. There were no stock options awarded for the six months ended June 30, 2009. For the three and six months ended June 30, 2009, pursuant to a separation agreement with a former executive vice president, we accelerated the vesting schedule for 1,094 options, all of which vested pursuant to the original terms of the awards. For the six months ended June 30, 2008, pursuant to a separation agreement with our former president, we modified options to purchase 4,678 shares by accelerating the vesting schedule, none of which would have vested pursuant to the original terms of the award. The incremental change in fair value per share of the modified awards was immaterial.

The following table provides a summary of our stock option award activity for the six months ended June 30, 2009:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (in years)
Outstanding at December 31, 2008	18,351	$ 41.68	6.8
Forfeited	(8,045)	41.39	
Outstanding at June 30, 2009	10,306	41.90	6.5

Vested and expected to vest at June 30, 2009	10,306	41.90	6.5
Exercisable at June 30, 2009	7,758	41.19	6.3

There was no intrinsic value of the options outstanding and exercisable at June 30, 2009, and December 31, 2008, as the exercise price of the options exceeded the closing market price of our common stock at the respective date. Total compensation cost related to stock options granted and not yet recognized in our condensed consolidated statement of operations as of June 30, 2009, was immaterial.

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Restricted Stock Awards

We began issuing shares of restricted common stock to employees in 2004 and to non-employee directors in 2005. Vesting conditions for our restricted stock awards are either time-based or market-based.

Time-Based Awards. The fair value of the time-based awards is amortized ratably over the requisite service period, generally over four years, and five years in connection with succession related grants to executive officers in March 2008. Time-based awards for non-employee directors generally vest on July 1st of the year following the date of the grant.

The following table sets forth the changes in non-vested time-based awards for the six months ended June 30, 2009:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2008	218,060	$ 52.59
Granted	104,079	12.21
Vested	(67,986)	51.93
Forfeited	(17,188)	35.87
Non-vested at June 30, 2009	236,965	36.26

The total compensation cost related to non-vested time-based awards expected to vest and not yet recognized in our condensed consolidated statement of operations as of June 30, 2009, is $6.5 million. This cost is expected to be recognized over a weighted-average period of 2.8 years. For the three months ended June 30, 2009, pursuant to a separation agreement with a former executive vice president, we accelerated time-based awards to vest 30,875 shares, all of which would have vested pursuant to the original terms of the award. For the six months ended June 30, 2008, pursuant to a separation agreement with our former president, we modified time-based awards to vest 10,954 shares by accelerating the vesting schedule, none of which would have vested pursuant to the original terms of the award, resulting in an increase in the original fair value of $0.2 million.

Market-Based Awards. The fair value of the market-based awards is amortized ratably over the requisite service period, primarily over three years for market-based awards. The market-based shares vest only upon the achievement of certain per share price thresholds and continuous employment during the vesting period. All compensation cost related to the market based-awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved. In June 2009, pursuant to a separation agreement with a former executive vice president, 21,263 shares were forfeited. In March 2008, pursuant to a separation agreement with our former president, we modified market-based awards to vest 1,539 shares by accelerating the vesting schedule, none of which would have vested pursuant to the original terms of the award. The incremental change in fair value per share of the modified awards was immaterial.

The weighted average grant date fair value per market-based share, including shares modified in 2008 pursuant to an agreement with our former president, was computed using the Monte Carlo pricing model using the following weighted average assumptions:

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Expected term of award	3 years	3 years
Risk-free interest rate	2.0%	2.3%

Volatility	59.0%	45.6%
Weighted average grant date fair value per share	$6.47	$45.85

For 2009, expected volatility was based on a blend of our historical and implied volatility and, for 2008, was based on our historical volatility. The expected lives of the awards were based on the requisite service period. The risk-free interest rate was based on the U.S. Treasury yields in effect at the time of grant or modification and extrapolated to approximate the life of the award. We do not expect to pay dividends, nor do we expect to declare dividends in the foreseeable future.

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The following table sets forth the changes in non-vested market-based awards for the six months ended June 30, 2009:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2008	72,683	$ 41.62
Granted	28,130	6.47
Forfeited	(21,263)	29.15
Non-vested at June 30, 2009	79,550	32.52

The total compensation cost related to non-vested market-based awards expected to vest and not yet recognized in our condensed consolidated statement of operations as of June 30, 2009, is $0.6 million. This cost is expected to be recognized over a weighted-average period of 1.7 years.

10. INCOME TAXES

We evaluate our estimated annual effective income tax rate on a quarterly basis based on current and forecasted business results and enacted tax laws. The estimated annual effective tax rate is adjusted quarterly based upon actual results and updated operating forecasts; consequently, based upon the mix and timing of our actual earnings compared to annual projections, our effective tax rate may vary quarterly. Tax expenses or tax benefits unrelated to current year ordinary income or loss are recognized entirely in the period identified as discrete items of tax. The quarterly income tax provision is generally comprised of tax on ordinary income or tax benefit on ordinary loss at the most recent estimated annual effective tax rate, adjusted for the effect of discrete items.

The loss we realized for the six months ended June 30, 2009, exceeds our projected loss for the year. As a result, we calculated our six month tax benefit by multiplying the current period loss by the statutory tax rate and then adding other statutory tax benefits such as percentage depletion. This required tax calculation limited the tax benefit realized during the six month period by $0.7 million. No similar limitation calculation was required for the six months ended June 30, 2008. The three month and six month tax rate for 2009 was impacted by the recording of $0.9 million and $0.3 million of net discrete tax benefit in the respective periods. The rates in 2008 were primarily impacted by a $2.7 million discrete benefit related to state refund claims based upon implemented 2008 state tax planning strategies. The discrete benefit for the 2009 second quarter was primarily due to the recognition of previously “uncertain tax positions” due to the completion of the Internal Revenue Service (“IRS”) examination of our 2005 and 2006 tax returns, discussed below.

As of June 30, 2009, we had a gross liability for uncertain tax positions of $0.9 million, of which $0.1 million was recorded in the current three month period. If recognized, all of this liability would affect our effective tax rate. This liability is reflected in federal and state income taxes payable in our accompanying condensed consolidated balance sheet. The IRS has completed its examination of our 2005 and 2006 tax years. As a result, the liability for uncertain tax positions decreased during the current three month period. Further, settlement for these years did not have a material impact on our income tax expense for the current three and six month periods.

As of the date of this filing, administrative review of our Colorado refund claims, filed through amended returns to implement 2008 state tax strategies, is still pending. We have received the applicable West Virginia refunds claimed via amended returns filed in 2008.

11. DISCONTINUED OPERATIONS

We offered our last sponsored drilling partnership in October 2007. In January 2008, we first announced that we had no plans to sponsor a new drilling partnership in 2008 and this decision was upheld again in 2009. As of June 30, 2009, all remaining contractual drilling and completion obligations were completed for all partnerships. The unused advance for future drilling contracts of $1.7 million as of December 31, 2008, was fully utilized as of June 30, 2009, with $0.2 million recognized in revenue and $0.3 million refunded to the partnerships.

As all partnership well drilling and completion activities have been completed and we currently do not have any plans in the foreseeable future to sponsor a drilling partnership, we believe it was appropriate to treat our oil and gas well drilling activities as discontinued operation for all periods presented. Prior period financial statements have been restated to present the activities of our oil and gas well drilling operations as discontinued operations.

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The tables below sets forth balance sheet and statement of operations data related to discontinued operations.

Balance Sheet Data: (in thousands)	December 31, 2008
Current assets:	
Cash and cash equivalents	$ 1,675
Current liabilities:	
Other accrued expenses	1,675

Statements of Operations Data: (in thousands)	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Revenues:			
Oil and gas well drilling	$ 2,887	$ 193	$ 5,970
Cost and expenses:			
Cost of oil and gas well drilling (1)	3	-	10
Income from discontinued operations before income taxes	2,884	193	5,960
Provision for income taxes	1,035	80	2,176
Income from discontinued operations, net of tax	$ 1,849	$ 113	$ 3,784

(1) For the three months ended June 30, 2008, and the six months ended June 30, 2009 and 2008, $0.5 million, $0.6 million and $0.6 million, respectively, previously included in cost of oil and gas well drilling have been reclassified to oil and gas production and well operations cost.

12. EARNINGS PER SHARE

The following is a reconciliation of basic and diluted weighted average shares outstanding:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(in thousands, except per share data)			
Weighted average common shares outstanding - basic	14,811	14,742	14,802	14,740
Weighted average common and common and common share equivalent shares outstanding - diluted	14,811	14,742	14,802	14,740
Loss from continuing operations	$(33,079)	$(42,561)	$(38,895)	$(58,424)
Income from discontinued operations, net of tax	-	1,849	113	3,784
Net loss	$(33,079)	$(40,712)	$(38,782)	$(54,640)
Earnings (loss) per common share - basic				
Continuing operations	$(2.23)	$(2.89)	$(2.63)	$(3.96)
Discontinued operations	-	0.13	0.01	0.25

Net loss	$(2.23)	$(2.76)	$(2.62)	$(3.71)
Earnings (loss) per common share - diluted				
Continuing operations	$(2.23)	$(2.89)	$(2.63)	$(3.96)
Discontinued operations	-	0.13	0.01	0.25
Net loss	$(2.23)	$(2.76)	$(2.62)	$(3.71)

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For the three and six months ended June 30, 2009 and 2008, the weighted average common shares outstanding for both basic and diluted were the same because the effect of dilutive securities were anti-dilutive due to our net loss for each of the periods. The following table sets forth the weighted average common share equivalents excluded from the calculation of diluted earnings per share due to their anti-dilutive effect.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in thousands)			
Weighted average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:				
Unamortized portion of restricted stock	286	72	297	78
Stock options	10	37	10	40
Non employee director deferred compensation	8	6	8	6
Total anti-dilutive common share equivalents	304	115	315	124

13. BUSINESS SEGMENTS

We separate our operating activities into three segments: oil and gas sales, natural gas marketing and well operations and pipeline income. All material inter-company accounts and transactions between segments have been eliminated.

Oil and Gas Sales. Our oil and gas sales segment represents revenues and expenses from the production and sale of oil and natural gas. Segment revenue includes oil and gas price risk management, net. Segment income (loss) consists of oil and gas sales revenues less its allocated share of oil and gas production and well operations cost, exploration expense, direct general and administrative expense and DD&A expense. Segment DD&A expense was $32.6 million and $65.7 million for the current year three and six months, and $20.8 million and $41.1 million for the prior year three and six months.

Natural Gas Marketing. Our natural gas marketing segment is composed of our wholly owned subsidiary, RNG, through which we purchase, aggregate and resell natural gas produced by us and others. Segment income primarily represents sales from natural gas marketing and direct interest income less costs of natural gas marketing and direct general and administrative expense.

Well Operations and Pipeline Income. We charge our affiliated partnerships and other third parties competitive industry rates for well operations and natural gas gathering. Segment revenue includes monthly operating and gas gathering fees we charge for each well which we operate that is owned by others, including our affiliated partnerships. Segment income consists of well operations and pipeline income revenues less its allocated share of oil and gas production and well operations cost and direct DD&A expense.

Unallocated amounts. Unallocated income includes unallocated other revenue less corporate general administrative expense, direct DD&A expense, direct interest income and interest expense.

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The following information sets forth our segment information, reclassified to exclude discontinued operations.

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(in thousands)			
Revenues:				
Oil and gas sales	$18,274	$(7,249)	$81,699	$22,087
Natural gas marketing	12,367	30,941	34,756	54,266
Well operations and pipeline income	2,937	2,438	5,733	4,790
Unallocated amounts	11	34	53	37
Total	$33,589	$26,164	$122,241	$81,180
Segment income (loss) before income taxes:				
Oil and gas sales	$(29,848)	$(51,646)	$(19,763)	$(63,711)
Natural gas marketing	377	872	892	2,204
Well operations and pipeline income	764	729	1,391	1,321
Unallocated amounts	(24,909)	(16,360)	(46,047)	(31,425)
Total	$(53,616)	$(66,405)	$(63,527)	$(91,611)

	June 30, 2009	December 31, 2008
	(in thousands)	
Segment assets:		
Oil and gas sales	$1,167,684	$ 1,247,687
Natural gas marketing	20,619	50,117
Well operations and pipeline income	59,480	50,052
Unallocated amounts	60,025	53,173
Assets related to discontinued oil and gas well drilling operations (1)	-	1,675
Total	$1,307,808	$ 1,402,704

(1) The December 31, 2008 amount excludes $0.4 million previously included in oil and gas well drilling operations, which has been reclassified to unallocated amounts. See Note 11, Discontinued Operations, for additional amounts reclassified.

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

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This periodic report contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act") and Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") regarding our business, financial condition, results of operations and prospects. All statements other than statements of historical facts included in and incorporated by reference into this report are forward-looking statements. Words such as expects, anticipates, intends, plans, believes, seeks, estimates and similar expressions or variations of such words are intended to identify forward-looking statements herein, which include statements of estimated oil and natural gas production and reserves, drilling plans, future cash flows, anticipated liquidity, anticipated capital expenditures and our management's strategies, plans and objectives. However, these are not the exclusive means of identifying forward-looking statements herein. Although forward-looking statements contained in this report reflect our good faith judgment, such statements can only be based on facts and factors currently known to us. Consequently, forward-looking statements are inherently subject to risks and uncertainties, including risks and uncertainties incidental to the exploration for, and the acquisition, development, production and marketing of, natural gas and oil, and actual outcomes may differ materially from the results and outcomes discussed in the forward-looking statements. Important factors that could cause actual results to differ materially from the forward looking statements include, but are not limited to:

- changes in production volumes, worldwide demand, and commodity prices for oil and natural gas;
- the timing and extent of our success in discovering, acquiring, developing and producing natural gas and oil reserves;
- our ability to acquire leases, drilling rigs, supplies and services at reasonable prices;
- the availability and cost of capital to us;
- risks incident to the drilling and operation of natural gas and oil wells;
- future production and development costs;
- the availability of sufficient pipeline and other transportation facilities to carry our production and the impact of these facilities on price;
- the effect of existing and future laws, governmental regulations and the political and economic climate of the United States of America;
- the effect of natural gas and oil derivatives activities;
- conditions in the capital markets; and
- losses possible from pending or future litigation.

Further, we urge you to carefully review and consider the cautionary statements made in this report, our annual report on Form 10-K for the year ended December 31, 2008, filed with the Securities and Exchange Commission ("SEC") on February 27, 2009 ("2008 Form 10-K"), and our other filings with the SEC and public disclosures. We caution you not to place undue reliance on forward-looking statements, which speak only as of the date of this report. We undertake no obligation to update any forward-looking statements in order to reflect any event or circumstance occurring after the date of this report or currently unknown facts or conditions or the occurrence of unanticipated events.

Overview

In the first quarter of 2008, we announced that we had no plans to sponsor new drilling partnerships in 2008. We affirmed this position in 2009 to change our business model from a partnership sponsor to that of an independent exploration and production company. Under our previous model, we drilled both partnership wells and wells for our own account. In the case of the partnership wells, we effectively limited drilling and operating risk as generally only 20% to 37% of the cost and risk of our drilling activity was borne by us.

Since we have discontinued the partnership sponsor model, our composite exposure to risks associated to drilling and operating oil and gas properties has increased because we drill and operate all oil and gas wells using our operating cash flows and debt. However, we expect greater returns for our successful efforts. Additionally, our general business risks are expected to increase slightly as our other segments become a less significant portion of our overall operating results. Finally, our current model allows us to focus on moderate risk projects with potential for higher returns as we are not as restrained by the previous low risk, low return partnership model. Since 2007, we have not had significant revenue from our drilling activities and as of June 30, 2009, we will no longer recognize any revenue related to our oil and gas well drilling operations as we have concluded all partnership drilling and completion activities; further, our well operations and pipeline income is expected to remain relatively constant as no new partnership wells will be added to our current number of wells operated.

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Results of Operations

Summary of Operations

The following table sets forth selected information regarding our results of operations, including production volumes, oil and gas sales, average sales prices received, average sales price including realized derivative gains and losses, average lifting cost, other operating income and expenses for the three and six months ended June 30, 2009, or the current year three and six month periods, and the three and six months ended June 30, 2008, or prior year three and six month periods.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2009	2008	Change	2009	2008	Change
Production (1)						
Oil (Bbls)	342,865	256,598	33.6%	686,749	512,050	34.1 %
Natural gas (Mcf)	9,152,871	7,257,184	26.1%	18,243,132	14,204,006	28.4 %
Natural gas equivalent (Mcfe) (2)	11,210,061	8,796,772	27.4%	22,363,626	17,276,306	29.4 %
Oil and Gas Sales (in thousands)						
Oil sales	$ 18,883	$ 31,627	-40.3%	$ 31,872	$ 52,354	-39.1 %
Gas sales	22,675	67,117	-66.2%	52,009	118,036	-55.9 %
Provision for underpayment of gas sales	-	(4,195)	100.0%	(2,581)	(4,195)	38.5 %
Total oil and gas sales	$ 41,558	$ 94,549	-56.0%	$ 81,300	$ 166,195	-51.1 %
Realized Gain (Loss) on Derivatives, net (in thousands)						
Oil derivatives	$ 4,818	$ (4,394)	-209.6%	$ 12,112	$ (5,700)	*
Natural gas derivatives	19,477	(10,960)	*	48,809	(12,065)	*
Total realized gain (loss) on derivatives, net	$ 24,295	$ (15,354)	*	$ 60,921	$ (17,765)	*
Average Sales Price (excluding realized gains (losses) on derivatives)						
Oil (per Bbl)	$ 55.07	$ 123.26	-55.3%	$ 46.41	$ 102.24	-54.6 %
Natural gas (per Mcf)	$ 2.48	$ 9.25	-73.2%	$ 2.85	$ 8.31	-65.7 %
Natural gas equivalent (per Mcfe)	$ 3.71	$ 11.23	-67.0%	$ 3.75	$ 9.86	-62.0 %
Average Sales Price (including realized gains (losses) on derivatives)						
Oil (per Bbl)	$ 69.13	$ 106.13	-34.9%	$ 64.05	$ 91.11	-29.7 %
Natural gas (per Mcf)	$ 4.61	$ 7.74	-40.4%	$ 5.53	$ 7.46	-25.9 %
Natural gas equivalent (per Mcfe)	$ 5.87	$ 9.48	-38.1%	$ 6.47	$ 8.83	-26.7 %
	$ 0.64	$ 1.13	-43.4%	$ 0.79	$ 1.13	-30.1 %

Average Lifting Cost per Mcfe (3)						
Natural gas marketing (in thousands) (4)	$ 375	$ 824	-54.5%	$ 886	$ 2,028	-56.3 %
Costs and Expenses (in thousands)						
Exploration expense	$ 3,133	$ 3,467	-9.6%	$ 8,776	$ 7,750	13.2 %
General and administrative expense	$ 14,784	$ 9,231	60.2%	$ 26,878	$ 19,054	41.1 %
Depreciation, depletion and amortization ("DD&A")	$ 33,844	$ 22,105	53.1%	$ 68,188	$ 43,236	57.7 %
Interest Expense (in thousands)	$ 9,420	$ 6,394	47.3%	$ 17,803	$ 11,326	57.2 %

*Represents percentages in excess of 250%
Amounts may not calculate due to rounding

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(1) Production is net and determined by multiplying the gross production volume of properties in which we have an interest by the percentage of the leasehold or other property interest we own.
(2) A ratio of energy content of natural gas and oil (six Mcf of natural gas equals one Bbl of oil) was used to obtain a conversion factor to convert oil production into equivalent Mcf of natural gas.
(3) Lifting costs represent oil and gas operating expenses which exclude production taxes.
(4) Represents sales from natural gas marketing less costs of natural gas marketing.

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Through April 2009, we continued to experience the same dramatic declines in oil and natural gas commodity prices that we had from late July 2008 through the end of 2008. As our production increased to 22.4 Bcfe for the first six months of 2009 compared to 17.3 Bcfe for prior year six month period, an increase of 29.4%, our average sales price declined 62% or $6.11 per Mcfe. While the impact of the significant changes in commodity prices have impacted our results of operations, we believe that we were successful in managing our operations to reduce the negative impacts through our derivative position. Our realized derivative gains for the current six month period of $60.9 million added an average of $2.72 per Mcfe produced during the first six months of 2009. Since May 2009, natural gas prices have rebounded slightly and oil prices have increased substantially; however, both commodity prices remain lower than those at the same time last year. At June 30, 2009, we estimate the net fair value of our open derivative positions, excluding the derivative positions attributed to our affiliated partnerships, to be a net asset of $56.9 million.

Depressed commodity prices for the six months 2009 as compared to the higher prices in prior six month period were the primary contributors to the $144.5 million change in revenues from oil and gas price risk management. Of the $144.5 million change, $78.7 million was related to an increase in realized derivative gains and the remaining $65.8 million was related to a decrease in unrealized derivative losses. Unrealized gains and losses are non-cash items and these non-cash charges to our condensed consolidated statement of operations will continue to fluctuate with the fluctuation in commodity prices until the positions mature or are closed, at which time they will become realized or cash items. While the required accounting treatment for derivatives that are not designated as hedges may result in significant swings in operating results over the life of the derivatives, the combination of the settled derivative contracts and the revenue received from the oil and gas sales at delivery are expected to result in a more predictable cash flow stream than would the sales contracts without the associated derivatives.

The table below, which demonstrates the volatility in the markets' projected commodity prices, sets forth the average NYMEX and CIG prices for the next 24 months (forward curve) from the selected dates.

Commodity	Index	December 31, 2007	June 30, 2008	December 31, 2008	June 30, 2009
Natural gas:	NYMEX	$ 8.12	$ 12.52	$ 6.62	$ 5.83
	CIG	6.78	8.86	4.49	4.87
Oil:	NYMEX	90.79	140.15	57.49	74.51

Oil and Gas Sales

The following tables set forth oil and natural gas production and average sales price by area.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2009	2008	Percentage Change	2009	2008	Percentage Change
Production						
Oil (Bbls)						
Rocky Mountain Region	339,911	254,048	33.8 %	681,268	507,581	34.2 %
Appalachian Basin	2,199	1,542	42.6 %	3,903	2,638	48.0 %
Michigan Basin	755	1,008	-25.1 %	1,578	1,831	-13.8 %
Total	342,865	256,598	33.6 %	686,749	512,050	34.1 %
Natural gas (Mcf)						
Rocky Mountain Region	7,759,553	5,873,549	32.1 %	15,588,316	11,473,314	35.9 %
Appalachian Basin	1,027,199	996,729	3.1 %	2,002,880	1,964,349	2.0 %
Michigan Basin	366,119	386,906	-5.4 %	651,936	766,343	-14.9 %

Total	9,152,871	7,257,184	26.1	%	18,243,132	14,204,006	28.4	%
Natural gas equivalent (Mcfe)								
Rocky Mountain Region	9,799,019	7,397,837	32.5	%	19,675,924	14,518,800	35.5	%
Appalachian Basin	1,040,393	1,005,981	3.4	%	2,026,298	1,980,177	2.3	%
Michigan Basin	370,649	392,954	-5.7	%	661,404	777,329	-14.9	%
Total	11,210,061	8,796,772	27.4	%	22,363,626	17,276,306	29.4	%

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	Three Months Ended June 30,			Six Months Ended June 30,		
	2009	2008	Percentage Change	2009	2008	Percentage Change
Average Sales Price (excluding derivative gains/losses)						
Oil (per Bbl)						
Rocky Mountain Region	$55.08	$123.30	-55.3 %	$46.42	$102.22	-54.6 %
Appalachian Basin	51.05	113.11	-54.9 %	44.09	104.38	-57.8 %
Michigan Basin	56.62	118.61	-52.3 %	46.31	108.45	-57.3 %
Weighted average price	55.07	123.26	-55.3 %	46.41	102.24	-54.6 %
Natural gas (per Mcf)						
Rocky Mountain Region	2.30	8.87	-74.1 %	2.62	8.02	-67.3 %
Appalachian Basin	3.63	11.09	-67.3 %	4.34	9.79	-55.7 %
Michigan Basin	3.08	10.41	-70.4 %	3.66	9.02	-59.4 %
Weighted average price	2.48	9.25	-73.2 %	2.85	8.31	-65.7 %
Natural gas equivalent (per Mcfe)						
Rocky Mountain Region	3.73	11.27	-66.9 %	3.69	9.91	-62.8 %
Appalachian Basin	3.65	11.13	-67.2 %	4.35	9.82	-55.7 %
Michigan Basin	3.16	10.56	-70.1 %	3.72	9.15	-59.3 %
Weighted average price	3.71	11.23	-67.0 %	3.75	9.86	-62.0 %

While our production increased to 11.2 Bcfe and 22.4 Bcfe for the current year three and six month periods, respectively, from 8.8 Bcfe and 17.3 Bcfe for the prior year three and six month periods, respectively, our oil and gas sales revenue for the current three and six month periods, excluding provision for underpayment of gas sales, decreased $57.2 million and $86.5 million, respectively, primarily due to the dramatic decline in commodity prices, partially offset by increased volumes. Approximately $136.7 million of the decrease in revenue for the current six month period was due to pricing, offset in part by increased production, which contributed $50.2 million. The decrease in oil and gas sales revenue was partially offset by realized derivative gains for first six month period 2009 of $60.9 million. See Oil and Gas Price Risk Management, Net discussion below.

Oil and Natural Gas Pricing. Our results of operations depend upon many factors, particularly the price of oil and natural gas and our ability to market our production effectively. Oil and natural gas prices have been among the most volatile of all commodity prices. These price variations have a material impact on our financial results. Oil and natural gas 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 have resulted in a local market oversupply situation from time to time. Like most producers in the region, we rely on major interstate pipeline companies to construct these pipelines to increase capacity, rendering the timing and availability of these facilities beyond our control. Oil pricing is also driven strongly by supply and demand relationships.

The price we receive for a large portion of the natural gas produced in the Rocky Mountain Region is based on a market basket of prices, which generally includes gas sold at CIG prices as well as gas sold at Mid-Continent or other nearby region prices. The CIG Index, and other indices for production delivered to other Rocky Mountain pipelines, has historically been less than the price received for natural gas produced in the eastern regions, which is NYMEX based.

Although 84.8% of our natural gas production for current three month period is produced in the Rocky Mountain Region, much of our Rocky Mountain natural gas pricing is based upon other indices in addition to CIG. The table below identifies the market for our oil and natural gas sales based on production for second quarter 2009. The market is the index that most closely relates to the price under which our oil and natural gas is sold.

Energy Market Exposure
For the Three Months Ended June 30, 2009

Area	Market	Commodity	Percent of Production
Piceance/Wattenberg	Colorado Interstate Gas (CIG)	Gas	37%
Colorado/North Dakota	NYMEX	Oil	18%
Piceance	San Juan Basin/Southern California	Gas	16%
NECO	Mid Continent (Panhandle Eastern)	Gas	12%
Appalachian	NYMEX	Gas	9%
Wattenberg	Colorado Liquids	Gas	4%
Michigan	Mich-Con/NYMEX	Gas	3%
Other	Other	Gas/Oil	1%
			100%

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Oil and Gas Production and Well Operations Costs. Oil and gas production and well operations cost includes our lifting cost, production taxes, the cost to operate wells and pipelines for our affiliated partnerships and other third parties (whose income is included in well operations and pipeline income) and certain production and engineering staff related overhead costs.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in thousands)			
Lifting cost	$7,201	$9,943	$17,522	$19,553
Production taxes	2,822	6,968	4,735	11,983
Costs of well operations and pipeline income	1,697	1,379	3,340	2,741
Overhead and other production expenses	2,324	3,040	4,808	5,256
Total oil and gas production and well operations cost	$14,044	$21,330	$30,405	$39,533

Lifting Costs. Lifting costs per Mcfe decreased 43.4% and 30.1% to $0.64 per Mcfe and $0.79 per Mcfe, respectively, for the current year three and six month periods from $1.13 per Mcfe for each of the same prior year three and six month periods. The decrease is primarily due to lower third party costs from service providers as a result of pressure by purchasers to reduce costs as oil and gas prices deteriorated, our own cost reduction initiatives, and increased production, which allows us to spread the fixed portion of our production costs over the increased volume and thereby lowering our per unit cost. The current year three and six month periods were also favorably impacted by a reimbursement of costs incurred in the first quarter of 2009. We expect future quarterly lifting cost to average from $0.80 per Mcfe to $0.90 per Mcfe for the remainder of the year.

Production Taxes. Production taxes decreased $4.1 million or 59.5% to $2.8 million and $7.2 million or 60.5% to $4.7 million for the current year three and six month periods. This decrease is primarily related to the 56% and 51.1% decrease in oil and gas sales for the current year three and six month periods.

Oil and Gas Price Risk Management, Net

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in thousands)			
Oil and gas price risk management, net:				
Realized gains (losses):				
Oil	$4,818	$(4,394)	$12,112	$(5,700)
Natural gas	19,477	(10,960)	48,809	(12,065)
Total realized gains (losses), net	24,295	(15,354)	60,921	(17,765)
Unrealized gains (losses):				
Reclassification of realized (gains) losses included in prior periods unrealized	(25,699)	9,690	(47,587)	704
Unrealized losses for the period	(21,880)	(96,134)	(12,935)	(127,047)
Total unrealized losses, net	(47,579)	(86,444)	(60,522)	(126,343)
Total oil and gas price risk management, net	$(23,284)	$(101,798)	$399	$(144,108)

Realized gains recognized in the current year three and six month periods are a result of lower oil and gas commodity prices at settlement compared to the respective strike price. During the current year three month period, we recorded derivative unrealized losses of $11.3 million on our oil swaps as the forward strip price of oil rebounded during the quarter, along with unrealized losses on our CIG basis swaps of $6.1 million as the forward basis differential between NYMEX and CIG has continued to narrow. During the current year six month period, we recorded derivative unrealized losses on our CIG basis swaps of $21.8 million and $9.8 million on our oil swaps for the same reasons cited above. These decreases were offset in part by unrealized gains on our collars of $13.9 million and natural gas swaps of $4.8 million as natural gas prices continued to decline compared to the previous forward curves.

Oil and gas price risk management, net includes realized gains and losses and unrealized changes in the fair value of derivative instruments related to our oil and natural gas production. Oil and gas price risk management, net does not include derivative transactions related to natural gas marketing, which are included in sales from and cost of natural gas marketing. See Note 3, Fair Value Measurements, and Note 4, Derivative Financial Instruments, to the accompanying condensed consolidated financial statements for additional details of our derivative financial instruments.

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Oil and Gas Sales Derivative Instruments. We use various derivative instruments to manage fluctuations in oil and natural gas prices. We have in place a series of collars, fixed-price swaps and basis swaps on a portion of our oil and natural gas production. Under our collar arrangements, if the applicable index rises above the ceiling price, we pay the counterparty; however, if the index drops below the floor price, the counterparty pays us. Under our swap arrangements, if the applicable index rises above the swap price, we pay the counterparty; however, if the index drops below the swap price, the counterparty pays us. Because we sell all our physical oil and natural gas at similar prices to the indexes inherent in our derivative instruments, we ultimately realize a price inherent in the collars in that we realize a price no less than the floor and no more than the ceiling and we ultimately realize the fixed price inherent in the swaps.

The following table identifies our derivative positions (excluding the derivative positions allocated to our affiliated partnerships) related to oil and gas sales in effect as of June 30, 2009, on our production by area. Our production volumes for second quarter 2009 were 342,865 Bbls of oil and 9.2 Bcf of natural gas.

	Collars				Fixed-Price Swaps		Basis Protection Swaps		
	Floors		Ceilings						
Commodity/ Operating Area/ Index	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Fair Value At June 30, 2009 (1) (in thousands)
Natural Gas									
Rocky Mountain Region									
CIG									
3Q 2009	3,644,418	$ 5.75	3,644,418	$ 8.90	-	$ -	-	$ -	$ 10,865
4Q 2009	2,658,504	6.70	2,658,504	10.26	1,009,794	9.20	-	-	13,256
2010	2,845,041	6.84	2,845,041	10.93	1,514,691	9.20	6,965,622	1.88	5,596
2011	1,019,241	4.75	1,019,241	9.45	-	-	7,660,544	1.88	(6,750)
2012	-	-	-	-	-	-	7,697,297	1.88	(6,423)
2013	-	-	-	-	-	-	6,897,498	1.88	(5,198)
PEPL									
3Q 2009	720,000	6.14	720,000	10.81	-	-	-	-	2,080
4Q 2009	580,000	7.81	580,000	12.68	240,000	10.91	-	-	3,684
2010	1,470,000	6.52	1,470,000	10.79	1,060,000	7.99	-	-	5,128
2011	390,000	5.76	390,000	9.56	-	-	-	-	121
NYMEX									
2010	416,949	5.75	416,949	8.30	6,215,579	5.64	-	-	(2,023)
2011	550,778	5.75	550,778	8.30	1,909,795	6.96	-	-	2
2012	-	-	-	-	2,061,321	6.96	-	-	(393)

Appalachian and Michigan Basins									
NYMEX									
3Q 2009	904,002	7.13	904,002	12.85	429,530	9.09	-	-	5,121
4Q 2009	867,004	9.00	867,004	15.66	429,239	9.09	-	-	5,442
2010	1,545,490	8.22	1,545,490	14.19	1,880,803	8.78	-	-	9,192
2011	265,406	6.62	265,406	11.65	799,803	9.60	-	-	2,211
2012	-	-	-	-	154,951	9.89	-	-	341
Total Natural Gas									42,250
Oil									
Rocky Mountain Region									
NYMEX									
3Q 2009	-	-	-	-	157,688	90.52	-	-	3,073
4Q 2009	-	-	-	-	157,688	90.52	-	-	2,779
2010	-	-	-	-	529,999	92.96	-	-	9,178
Total Oil									15,030
Total Natural Gas and Oil									$ 57,280

(1)Approximately 84% of the total fair value of the derivative instruments were measured using significant unobservable inputs (Level 3 assets and liabilities, see Note 3, Fair Value Measurements, to the accompanying condensed consolidated financial statements.

In July 2009, we entered into a NYMEX-based oil swap covering approximately 30,200 gross barrels per month for calendar year 2011 at $70.75 per barrel. The gross barrels include the allocated portion of the estimated production of our affiliated partnerships.

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Natural Gas Marketing

The decreases in sales from and cost of natural gas marketing for the current year three month period compared to the same prior year period is primarily due to a decrease in prices of approximately 33%, along with increased unrealized losses and a decrease in realized gains. For the current year six month period, prices declined 55% from the same prior year period, partially offset by increases in realized and unrealized derivative gains.

Our natural gas marketing focuses on the purchase, aggregation and sale of natural gas produced in our eastern operating areas. We purchase for resale, the production of other third party producers in the Appalachian Basin, including our affiliated partnerships. Our derivative instruments related to natural gas marketing include both physical and cash-settled derivatives. We offer fixed-price derivative contracts for the purchase or sale of physical gas and enter into cash-settled derivative positions with counterparties in order to offset those same physical positions. We do not take speculative positions on commodity prices.

Natural Gas Marketing Derivative Instruments. The following table identifies our derivative positions related to our gas marketing in effect as of June 30, 2009.

	Fixed-Price Swaps		Basis Protection Swaps		Fair Value
Commodity/ Derivative Instrument	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	At June 30, 2009 (in thousands)
Natural Gas Physical Sales					
3Q 2009	61,320	$ 7.66	262,412	$ 0.13	$ 210
4Q 2009	19,293	6.98	177,761	0.25	70
2010	74,610	6.94	139,545	0.39	106
Financial Purchases					
3Q 2009	61,191	6.80	-	-	(177)
4Q 2009	39,293	9.32	61,000	0.17	(180)
2010	104,610	8.31	90,000	0.17	(265)
Financial Sales					
3Q 2009	250,500	9.39	141,250	0.32	1,391
4Q 2009	248,500	8.90	166,050	0.32	1,032
2010	695,000	8.71	-	-	1,835
2011	150,000	8.44	-	-	208
Physical Purchases					
3Q 2009	250,995	9.56	46,752	0.32	(1,391)
4Q 2009	228,665	9.60	15,584	0.32	(1,068)
2010	665,000	9.14	-	-	(1,955)
2011	150,000	8.61	-	-	(221)
					$ (405)

Total Natural
Gas

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Other Costs and Expenses

Exploration Expense.

The following table sets forth the major components of exploration expense.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in thousands)			
Amortization and impairment of unproved properties	$ 518	$ 500	$ 1,132	$ 942
Exploratory dry holes	106	-	937	1,100
Geological and geophysical costs	214	598	467	1,444
Operating, personnel and other (1)	2,295	2,369	6,240	4,264
Total exploration expense	$ 3,133	$ 3,467	$ 8,776	$ 7,750

(1) The three and six months ended June 30, 2009, include $0.3 million and $1.2 million, respectively, for the demobilization of drilling rigs in the Piceance Basin; the six months ended June 30, 2009, also includes $0.7 million related to tubular inventory impairments.

General and Administrative Expense.

General and administrative expense increased from $9.2 million to $14.8 million for the current year three month period compared to same prior year period, an increase of $5.6 million. The increase is primarily related to a separation agreement with our former executive vice president of $2.9 million and increased staffing and related payroll benefits, including stock-based compensation expense, of $1.7 million and corporate relocation assistance costs of $1 million offset in part by a decrease in professional fees of $0.6 million.

For the current year six month period, general and administrative expense increased to $26.9 million from $19.1 million for the same prior year period, an increase of $7.8 million. The increase is primarily related to increased staffing and related payroll benefits, including stock-based compensation, of $4.7 million, the expensing of previously capitalized acquisition related costs of $1.5 million pursuant to the adoption of a new accounting standard and corporate relocation assistance costs of $1.1 million. See Note 2, Recent Accounting Standards, to the accompanying condensed consolidated financial statements.

Depreciation, Depletion, and Amortization.

DD&A expense includes depreciation and amortization expense related to non-oil and natural gas properties as well as oil and natural gas properties. DD&A expense for non-oil and natural gas properties was $2 million and $4 million, respectively, for the current year three and six month periods compared to $1.6 million and $3.1 million, respectively, for the same prior year three and six month periods.

DD&A expense related to oil and natural gas properties is directly related to reserves and production volumes. DD&A expense is primarily based upon year-end proved developed producing oil and gas reserves. These reserves are priced at the price of oil and natural gas as of December 31 each year. If prices increase, the estimated volumes of oil and gas reserves will increase, resulting in decreases in the rate of DD&A expense per unit of production. If prices decrease, as they did from December 31, 2007 to December 31, 2008, the estimated volumes of oil and gas reserves will decrease resulting in increases in the rate of DD&A expense per unit of production. The cost to acquire acreage, drill, complete and equip new wells has risen significantly over the past five years and is a major contributing factor, as well as our 2008 reduction in proved developed reserves for the increased DD&A expense rate.

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The following table sets forth our DD&A expense rate for oil and gas properties by area.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2009	2008	Percent Change	2009	2008	Percent Change
	(per Mcfe)					
Rocky Mountain Region:						
Wattenberg Field	$ 3.90	$ 3.39	15.0 %	$ 3.99	$ 3.38	18.0 %
Piceance Basin	2.36	1.82	29.7 %	2.36	1.81	30.4 %
NECO	1.79	1.30	37.7 %	1.80	1.30	38.5 %
Appalachian Basin	1.81	1.52	19.1 %	1.84	1.49	23.5 %
Michigan Basin	1.51	1.31	15.3 %	1.50	1.31	14.5 %

The increasing trend in DD&A rates over the past several years on a per unit basis eased somewhat in the second quarter of 2009 compared to the first quarter of 2009 due to lower drilling, completion and tubular goods costs, which are the direct result of service providers and suppliers lowering their rates due to lower demand for oil field services. Our DD&A expense rate for oil and gas properties decreased from $2.90 per Mcfe in the first quarter of 2009 to $2.84 per Mcfe in the second quarter of 2009.

Non-Operating Income/Expense

Interest Income. The decrease in our interest income for three and six months ended 2009 compared to the same prior year three and six month periods was the result of lower interest bearing cash balances and lower interest rates.

Interest Expense. The increase in our interest expense for the current year three and six month periods was primarily due to significantly higher average outstanding debt balances of our credit facility and additional amortized debt issuance costs associated with the Sixth Amendment of our credit facility. Interest expense is net of capitalized interest. Interest costs capitalized for the current year three and six month periods were $0.1 million and $0.8 million, respectively, compared to $0.8 million and $1.4 million for the same prior year three and six month periods. This significant decrease is due to our decreased number of wells drilled in 2009. We have historically utilized our daily cash balances to reduce our line of credit borrowings, thereby lowering our interest costs.

Provision/Benefit for Income Taxes

The effective income tax rate for continuing operations for the current three and six month periods was 38% and 39% compared to 36% for the same prior year three and six month periods, respectively. The current year three and six month rates are reflective of the tax benefit from our percentage depletion deduction adding to the limited tax benefit of our current period net operating loss (“NOL”) recorded at our statutory tax rate. The prior year three and six month rates were based upon full year forecasted income at the end of each period.

The current year three month period includes an NOL tax benefit of $0.9 million due to the reduction of our 2009 NOL tax benefit limitation from $1.6 million at March 31, 2009, to $0.7 million at June 30, 2009. The tax benefit recorded for the second quarter of 2009 also includes a $0.5 million discrete benefit from the recognition of previously uncertain tax positions due to the completion of the IRS examination of our 2005 and 2006 tax years. In 2008, a second quarter discrete benefit of $1.4 million was recorded related to the implementation of state tax strategies that impacted prior years. The impact of these strategies also affected our rate used to establish deferred taxes and resulted in a deferred tax benefit of $1.3 million in the second quarter of 2008.

Unrealized losses on derivative positions are not deductible and give rise to a deferred tax liability; conversely, unrealized gains on derivative positions are not taxable and result in a deferred tax asset. During the current six month period, we had a $23.2 million reduction of our previously recorded deferred tax liability associated with unrealized gains. This reduction was primarily due to the realization of previously unrealized gains. Comparatively, for the same prior year six month period, we recorded in other current assets in our accompanying condensed consolidated balance sheet an additional $49.1 million to our deferred tax asset associated with unrealized losses. Further, the operating loss in the current six month period has resulted in a current net tax benefit of $3.7 million, which is recorded in other current assets as of June 30, 2009 versus $16.2 million of current net tax benefit recorded at June 30, 2008.

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Discontinued Operations

We offered our last sponsored drilling partnership in October 2007. In January 2008, we first announced that we had no plans to sponsor a new drilling partnership in 2008 and this decision was upheld again in 2009. As of June 30, 2009, all remaining contractual drilling and completion obligations were completed for all partnerships. The unused advance for future drilling contracts of $1.7 million as of December 31, 2008, was fully utilized as of June 30, 2009, with $0.2 million recognized in revenue and $0.3 million refunded to the partnerships.

As we currently do not have any plans in the foreseeable future to sponsor a drilling partnership, we believe it was appropriate to treat our oil and gas well drilling activities as discontinued operations for all periods presented. Prior period financial statements have been restated to present the activities of our oil and gas well drilling operations as discontinued operations.

Liquidity and Capital Resources

Cash flows from operations and our bank credit facility are the primary sources of liquidity for us to satisfy our operating expenses and fund our capital expenditures. We had $132 million of available borrowing capacity under our $350 million bank credit facility as of June 30, 2009. Cash provided by operating activities was $60.7 million for first six months 2009 compared to $67.7 million for the same prior year period. The $7 million decrease in first six months of 2009 was primarily due to the timing of the payment of accounts payable obligations and capital spending. Changes in cash flows from operations are largely due to the same factors that affect our net income, excluding non-cash items which are primarily DD&A and unrealized gains and losses on derivative transactions. See the discussion under Results of Operations above. Cash flows used in investing activities, primarily drilling capital expenditures, decreased $22.6 million, or 17.9%, from $126.6 million the prior year six months to $104 million for the current year six month period. Cash flows provided from financing activities increased $6.9 million from a $7.4 million source of cash for the prior year six months to $14.3 million for the current year six months. This increase was primarily due to increased net borrowing to fund working capital changes.

Changes in market prices for oil and natural gas, our ability to increase production, the impact of realized gains and losses on our oil and natural gas derivative instruments and changes in costs are the principal determinants of the level of our cash flows from operations. Oil and natural gas sales for current six month period were approximately 51.1% lower than the same prior year six month period, resulting from a 62% decrease in average oil and natural gas prices offset in part by a 29.4% increase in oil and natural gas production. While a decline in oil and natural gas prices would affect the amount of cash from operations that would be generated, we have oil and natural gas derivative positions in place, as of the date of this filing, covering 60.1% of our expected oil production and 64.3% of our expected natural gas production for the remainder of 2009, at average prices of $90.52 per Bbl and $7.11 per Mcf, respectively. These contracts reduce the impact of price changes for a substantial portion of our 2009 cash from operations.

Our primary use of funds is for capital expenditures. As a result of the current unstable conditions in the commodity and financial markets, we have significantly reduced our planned 2009 capital expenditures to $108 million which represents an approximate 65% decrease from our 2008 capital expenditures. With this reduction, we estimate our 2009 production will increase by approximately 12% over 2008 in part due to increased production from wells drilled in the latter part of 2008. We believe, based on the current commodity price environment, our cash flows from operations will fund our reduced 2009 capital spending program. We expect to manage capital expenditures within our cash flows from operations for the foreseeable future until commodity prices and capital markets are more favorable. In order to continue to maintain or grow our production, we would need to commit greater amounts of capital in 2010 and beyond. If capital is not available or is constrained in the future, we will be limited to our cash flows from operations and liquidity under our credit facility as the sources of funding for our capital expenditures. Because oil and gas produced from our existing properties declines rapidly in the first two years of production, we could not maintain our current level of oil and gas production and cash flows from operations if capital markets and commodity prices remain in their current depressed state for a prolonged period beyond 2009, which would have a material negative impact on our operations in 2010 and beyond.

We considered the possibility of reduced available liquidity in planning our 2009 drilling program and believe we will have adequate cash flows from operations during the year to execute our planned capital expenditures without drawing additional funds from our credit facility. Currently, we operate approximately 96% of our properties, allowing us to control the pace of substantially all of our planned capital expenditures. Consequently, we may elect to defer a substantial portion of our planned capital expenditures for 2009 and beyond if market conditions worsen.

In addition to deferring capital expenditures to reduce borrowings under our credit facility, other sources of liquidity include the fair value of our oil and natural gas derivative positions, excluding the derivative positions allocated to our affiliated partnerships, of $56.9 million as well as our available cash balance which was $21.9 million as of June 30, 2009.

We have experienced no impediments in our ability to access borrowings under our current bank credit facility. We continue to monitor market events and circumstances and their potential impacts on each of the eleven lenders that comprise our bank credit facility. Our $350 million bank credit facility borrowing base is subject to size redeterminations each April and October based upon a quantification of our proved reserves at each December 31st and June 30th, respectively. A commodity price deck reflective of the current and future commodity pricing environment is utilized by our lenders to quantify our reserve reports and determine the underlying borrowing base.

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As a result of our April 2009 borrowing base redetermination and in conjunction with the sixth amendment to our credit facility on May 22, 2009 ("Sixth Amendment"), our borrowing base decreased from $375 million to $350 million. The decrease was driven primarily by the continued weakness in the oil and gas markets, partially offset by increases in proved producing reserves from drilling operations. While we have continued to add producing reserves through our drilling operations since our redetermination, we believe the significant decrease in commodity prices and turmoil in the credit markets could have a negative impact on our October 2009 borrowing base redetermination, which will be sized based upon the quantification of our reserves as of June 30, 2009. In addition to the decrease in our borrowing base, the Sixth Amendment included several changes: an extension of the maturity date to May 22, 2012; an increase in our ability to raise additional debt from $350 million to $450 million; an amendment to our ratio of consolidated funded indebtedness to consolidated EBITDA from 3.75 to 1.00 to 4.25 to 1.00 through December 31, 2010, 4.00 to 1.00 through June 30, 2011 and 3.75 to 1.00 thereafter; and an amended pricing grid of between LIBOR plus 2.25% and LIBOR plus 3.25%, depending on the drawn percentage of the credit facility.

At June 30, 2009, we had $132 million available for borrowing under our $350 million credit facility. While we expect our borrowing base to be reduced as a result of the significant decrease in mid year 2009 commodity prices at our pending semi-annual redetermination, we believe that producing reserves added since our last redetermination and our oil and natural gas derivative positions in place could mitigate the risk of a significant decrease in our borrowing base in 2009. We also believe that while transactional costs have increased for credit facilities like ours, the impact of an increase in interest and commitment fees on our outstanding balance and commitments will not have a material adverse effect on our liquidity for the next year. If economic conditions deteriorate further in 2009 and 2010, our ability to redetermine our credit facility and provide adequate liquidity to continue our drilling programs could be negatively impacted in 2010 and beyond. There is no assurance that our borrowing base will not be reduced from its current level.

We are subject to quarterly financial debt covenants on our bank credit facility. Currently, our key credit facility debt covenants require that we maintain: 1) total debt of less than 4.25 times earnings before interest, taxes, depreciation, amortization and capital expenditures ("EBITDAX") and 2) an adjusted working capital ratio of at least 1.0 to 1.0. Our adjusted working capital ratio is calculated by reducing our current assets and liabilities by any impact of recording the fair value of our oil and gas derivative instruments and adding our available borrowings on our bank credit facilities to our current assets. In addition, the impact of any current portion of our debt is eliminated from the current liabilities. Therefore, any change in our available borrowings under our credit facility impacts our working capital ratio. We were in compliance with all debt covenants at June 30, 2009.

We believe we have sufficient liquidity and capital resources to conduct our business and remain compliant with our debt covenants throughout the next year based upon our 2009 and 2010 cash flow projections, anticipated capital requirements, the discretionary nature of our capital expenditures and available capacity under our bank credit facility. However, we cannot predict with any certainty the impact to our future business of any continued uncertainty or further deterioration in the financial markets. We will continue to closely monitor our liquidity and the credit markets and may choose to access them opportunistically should conditions and capital market liquidity improve.

We filed a shelf registration statement on Form S-3 with the SEC on November 26, 2008. The shelf provides for an aggregate of $500 million, through the potential sale of debt securities, common stock or preferred stock, either separately or represented by depository shares, warrants and purchase contracts, as well as units that may include any of these securities or securities of other entities. The shelf registration statement is intended to allow us to be proactive in our ability to raise capital should the need arise, and to have the flexibility to raise such funds in one or more offerings should we perceive the market conditions to be favorable. This shelf registration statement was declared effective by the SEC on January 30, 2009.

See Part I, Item 3, Quantitative and Qualitative Disclosure about Market Risk, for our discussion of credit risk.

2009 Outlook

We currently estimate that our 2009 production will be approximately 43.4 Bcfe or a 12% increase over our 2008 production of 38.7 Bcfe. Our estimated 2009 capital budget of $108 million represents an approximate 65% decrease compared to 2008. We selected this level of spending with the goal of remaining debt neutral to help maintain adequate liquidity during 2009. Through June 30, 2009, we have incurred costs of approximately $67 million related to our 2009 capital budget. Actual oil and gas prices may vary considerably from our projections. We have used oil and natural gas derivatives contracts in order to reduce the effects of volatile commodity prices. As of June 30, 2009, we had oil and natural gas hedges in place covering 60.1% of our expected oil production and 64.3% of our expected natural gas production for the remainder of 2009.

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Our current 2009 drilling plans continue to be focused primarily in the Rocky Mountain Region. We plan to drill approximately 105 gross, 84 net, wells in the Rocky Mountain Region and the Appalachian Basin. Exclusive of exploratory wells, through June 30, 2009, we have drilled 48 gross wells compared to 188 gross wells for the same period last year. We have had one drilling rig operating for most of the year in the Wattenberg Field. We plan to continue to drill with the one rig in the oil rich sections of the field to take advantage of the relatively favorable oil prices along with high natural gas liquids and Btu content of these wells. We are currently evaluating the exploration potential of the Marcellus Formation in the Appalachian Basin, where we have been an operator for over 30 years and currently operate approximately 2,100 wells within the Marcellus “Fairway” area. In July 2009, we added 4,900 acres in the Fairway in central Pennsylvania giving us a total of approximately 53,000 acres for potential development. We have drilled our fifth Marcellus well and plan four more vertical tests this year. We are in the process of permitting for a ten square mile 3D seismic survey in the Marcellus Shale during the third quarter of 2009, which we plan to do prior to attempting our first horizontal Marcellus well.

Contractual Obligations and Contingent Commitments

The table below sets forth our contractual obligations and contingent commitments as of June 30, 2009:

	Payments due by period				
Contractual Obligations and Contingent Commitments	Total	Less than 1 year	1-3years	3-5years	More than 5 years
			(in thousands)		
Long term liabilities reflected on the condensed consolidated balance sheet (1)					
Long-term debt	$ 418,512	$ -	$ 218,000	$ -	$ 200,512
Asset retirement obligations	24,441	50	100	100	24,191
Derivative contracts (2)	44,211	6,013	25,444	12,754	-
Derivative contracts - partnerships (3)	4,621	2,264	2,357	-	-
Production tax liability	30,986	22,061	8,925	-	-
Other liabilities (4)	7,761	354	1,056	1,056	5,295
	530,532	30,742	255,882	13,910	229,998
Commitments, contingencies and other arrangements (5)					
Interest on long-term debt(6)	232,957	32,255	63,677	48,720	88,305
Operating leases	7,757	2,335	2,698	1,671	1,053
Rig commitments (7)	8,699	8,459	240	-	-
Drilling commitments(8)	1,800	-	-	-	1,800
Firm transportation and processing agreements (9)	208,545	827	36,103	50,334	121,281
Other	750	125	250	250	125
	460,508	44,001	102,968	100,975	212,564

Total	$ 991,040	$ 74,743	$ 358,850	$ 114,885	$ 442,562

(1) Table does not include net deferred income tax liability to taxing authorities of $169 million as of June 30, 2009, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

(2) Represents our gross liability related to the fair value of derivative positions, including the fair value of derivative contracts we entered into on behalf of our affiliated partnerships as the managing general partner. We have a related receivable from the partnerships of $14.3 million as of June 30, 2009.

(3) Represents our affiliated partnerships' allocated portion of the fair value of our gross derivative assets as of June 30, 2009.

(4) Includes funds held from revenue distribution to third party investors for plugging liabilities related to wells we operate and deferred officer compensation.

(5) Table does not include maximum annual repurchase obligations to investing partners of $15.1 million as of June 30, 2009, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

(6) Amounts presented for long term debt consist of amounts related to our 12% senior notes and our outstanding credit facility. The interest on long term debt includes $210.1 million payable to the holders of our 12% senior notes and $22.9 million related to our outstanding balance of $218 million on our credit facility as of June 30, 2009, based on an imputed interest rate of 3.8%.

(7) Drilling rig commitments in the above table reflect our maximum obligation for the services of two drilling rigs. This commitment includes $1.4 million related to a rig sublet to a third party and remains our obligation should the third party default on terms of the sublet agreement.

(8) See Note 8, Commitments and Contingencies – Drilling and Development Agreements, to our accompanying condensed consolidated financial statements.

(9) Represents our gross commitment, including amounts for volumes transported or sold on behalf of our affiliated partnerships and other working interest owners. We will recognize in our financial statements our proportionate share based on our working interest.

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As managing general partner of 33 partnerships, we have liability for any potential casualty losses in excess of the partnership assets and insurance. We believe that the casualty insurance coverage we and our subcontractors carry is adequate to meet this potential liability.

For information regarding our legal proceedings, see Note –8, Commitments and Contingencies – Litigation, to our accompanying condensed consolidated financial statements included in this report. From time to time we are a party to various other legal proceedings in the ordinary course of business. We are not currently a party to any litigation that we believe would have a materially adverse affect on our business, financial condition, results of operations, or liquidity.

Drilling Activity

The following table summarizes our development and exploratory drilling activity for the three and six months ended June 30, 2009 and 2008. There is no correlation between the number of productive wells completed during any period and the aggregate reserves attributable to those wells. Productive wells consist of producing wells and wells capable of commercial production.

Drilling Activity

	Three Months Ended June 30,				Six Months Ended June 30,			
	2009		2008		2009		2008	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development								
Productive (1)	24.0	19.7	91.0	82.8	47.0	41.0	183.0	141.6
Dry	-	-	5.0	5.0	1.0	0.5	5.0	5.0
Total development	24.0	19.7	96.0	87.8	48.0	41.5	188.0	146.6
Exploratory								
Productive (1)	-	-	-	-	1.0	0.5	-	-
Dry	-	-	4.0	3.8	-	-	6.0	5.8
Pending determination	-	-	1.0	1.0	3.0	2.5	8.0	8.0
Total exploratory	-	-	5.0	4.8	4.0	3.0	14.0	13.8
Total Drilling Activity	24.0	19.7	101.0	92.6	52.0	44.5	202.0	160.4

(1) As of June 30, 2009, a total of 39 productive wells, 26 drilled in 2009 and 13 drilled in 2008, were waiting to be fractured and/or for gas pipeline connection.

The following table sets forth the wells we drilled by operating area during the periods indicated.

	Three Months Ended June 30,				Six Months Ended June 30,			
	2009		2008		2009		2008	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain Region:								
Wattenberg	24.0	19.7	35.0	33.6	42.0	37.5	80.0	55.3
Piceance	-	-	11.0	11.0	1.0	1.0	32.0	24.5
NECO	-	-	38.0	32.0	5.0	2.5	67.0	58.6
North Dakota	-	-	1.0	0.2	1.0	0.5	1.0	0.2
	24.0	19.7	85.0	76.8	49.0	41.5	180.0	138.6

Total Rocky Mountain Region								
Appalachian Basin	-	-	14.0	14.0	3.0	3.0	19.0	19.0
Michigan	-	-	1.0	0.8	-	-	1.0	0.8
Fort Worth Basin	-	-	1.0	1.0	-	-	2.0	2.0
Total	24.0	19.7	101.0	92.6	52.0	44.5	202.0	160.4

Commitments and Contingencies

See Note 8, Commitments and Contingencies, to the accompanying condensed consolidated financial statements.

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Recent Accounting Standards

See Note 2, Recent Accounting Standards, to the accompanying condensed consolidated financial statements.

Critical Accounting Polices and Estimates

The preparation of the accompanying condensed consolidated financial statements in conformity with accounting principles generally accepted in the U.S. requires management to use judgment in making estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities and the reported amounts of revenue and expenses.

We believe that our accounting policies for revenue recognition, derivatives instruments, oil and gas properties, deferred income tax asset valuation and purchase accounting are based on, among other things, judgments and assumptions made by management that include inherent risks and uncertainties. There have been no significant changes to these policies or in the underlying accounting assumptions and estimates used in these critical accounting policies from those disclosed in the consolidated financial statements and accompanying notes contained in our 2008 Form 10-K.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Market-Sensitive Instruments and Risk Management

We are exposed to market risks associated with interest rates, commodity prices and credit exposure. Management has established risk management processes to monitor and manage these market risks.

Interest Rate Risk

We are exposed to risk resulting from changes in interest rates primarily as it relates to interest we earn on our deposit accounts, including cash, cash equivalents and designated cash, current and noncurrent, and interest we pay on borrowings under our revolving credit facility. Our interest-bearing deposit accounts include money market accounts, certificates of deposit and checking and savings accounts with various banks. The amount of our interest-bearing cash and cash equivalents as of June 30, 2009, is $41.4 million with an average interest rate of 1.4%.

Commodity Price Risk

See Note 4, Derivative Financial Instruments, to the accompanying condensed consolidated financial statements included in this report for additional disclosure regarding our derivative financial instruments including, but not limited to, the accounting for our derivative financial instruments and a summary of our open derivative positions as of June 30, 2009.

We are exposed to the effect of market fluctuations in the prices of oil and natural gas. Price risk represents the potential risk of loss from adverse changes in the market price of oil and natural gas commodities. We employ established policies and procedures to manage the risks associated with these market fluctuations using derivative instruments. Our policy prohibits the use of oil and natural gas derivative instruments for speculative purposes.

Validation of a contract's fair value is performed internally and while we use common industry practices to develop our valuation techniques, changes in our pricing methodologies or the underlying assumptions could result in significantly different fair values. While we believe these valuation methods are appropriate and consistent with those used by other market participants, the use of different methodologies, or assumptions, to determine the fair value of certain financial instruments could result in a different estimate of fair value.

Derivative Strategies. Our results of operations and operating cash flows are affected by changes in market prices for oil and natural gas. To mitigate a portion of our exposure to adverse market changes, we have entered into various derivative contracts.

- For our oil and gas sales, we enter into, for our own and affiliated partnerships' production, derivative contracts to protect against price declines in future periods. While we structure these derivatives to reduce our exposure to changes in price associated with the derivative commodity, they also limit the benefit we might otherwise have received from price increases in the physical market.

- For our natural gas marketing, we enter into fixed-price physical purchase and sale agreements that qualify as derivative contracts. In order to offset the fixed-price physical derivatives in our natural gas marketing, we enter into financial derivative instruments that have the effect of locking in the prices we will receive or pay for the same volumes and period, offsetting the physical derivative.

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We believe our derivative instruments continue to be effective in achieving the risk management objectives for which they were intended.

As of June 30, 2009, our derivative instruments were comprised of commodity collars and swaps, basis protection swaps and physical sales and purchases.

- Collars contain a fixed floor price (put) and ceiling price (call). If the market price falls below the fixed put strike price, we receive the market price from the purchaser and receive the difference between the put strike price and market price from the counterparty. If the market price exceeds the fixed call strike price, we receive the market price from the purchaser and pay the difference between the call strike price and market price to the counterparty. If the market price is between the put and call strike price, no payments are due to or from the counterparty.

- Swaps are arrangements that guarantee a fixed price. If the market price is below the fixed contract price, we receive the market price from the purchaser and receive the difference between the market price and the fixed contract price from the counterparty. If the market price is above the fixed contract price, we receive the market price from the purchaser and pay the difference between the market price and the fixed contract price to the counterparty.

- Basis protection swaps are arrangements that guarantee a price differential for natural gas from a specified delivery point. For CIG basis protection swaps, which have negative differentials to NYMEX, we receive a payment from the counterparty if the price differential is greater than the stated terms of the contract and pay the counterparty if the price differential is less than the stated terms of the contract.

- Physical sales and purchases are derivatives for fixed-price physical transactions where we sell or purchase third party supply at fixed rates. These physical derivatives are offset by financial swaps: for a physical sale the offset is a swap purchase and for a physical purchase the offset is a swap sale.

The following table presents monthly average NYMEX and CIG closing prices for oil and natural gas for the six months ended June 30, 2009, and the year ended December 31, 2008, as well as average sales prices we realized for the respective commodity.

	Six Months Ended June 30, 2009	Year Ended December 31, 2008
Average Index Closing Prices		
Natural Gas (per MMbtu)		
CIG	$ 2.82	$ 6.22
NYMEX	4.19	9.04
Oil (per Barrel)		
NYMEX	44.80	104.42
Average Sales Price		
Natural Gas	2.85	6.98

Oil	46.41	89.77

Based on a sensitivity analysis as of June 30, 2009, it was estimated that a 10% increase in oil and natural gas prices, inclusive of basis, over the entire period for which we have derivatives then in place would have resulted in a decrease in fair value of $35.8 million and a 10% decrease in oil and natural gas prices would have resulted in an increase in fair value of $36.2 million.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. We attempt to reduce credit risk by diversifying our counterparty exposure and entering into transactions with high-quality counterparties. When exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. We have had no counterparty default losses.

Our receivables are from a diverse group of companies, including major energy companies, both upstream and mid-stream, financial institutions and end-users in various industries related to our gas marketing group. We monitor their creditworthiness through credit reports and rating agency reports.

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Our derivative financial instruments expose us to the credit risk of nonperformance by the counterparty to the contracts. We primarily use two financial institutions, who are also major lenders in our credit facility agreement, as counterparties to our derivative contracts. We have evaluated the credit risk of the counterparties holding our derivative assets using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant. As of June 30, 2009, no valuation allowance was recorded.

The recent disruption in the credit market has had a significant adverse impact on a number of financial institutions. We monitor the creditworthiness of the financial institutions with which we transact, giving consideration to the reports of credit agencies and their related ratings. While we believe that our monitoring procedures are sufficient and customary, no amount of analysis can guarantee performance in these uncertain times.

Disclosure of Limitations

Because the information above included only those exposures that exist at June 30, 2009, it does not consider those exposures or positions which could arise after that date. As a result, our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, our hedging strategies at the time, and interest rates and commodity prices at the time.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of June 30, 2009, we carried out an evaluation under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rules 13a-15(e) and 15d-15(e). This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports that we file or submit 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 our management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely discussion regarding required financial disclosure.

Based on the results of this evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2009.

Changes in Internal Control over Financial Reporting

We made no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) during the quarter ended June 30, 2009, that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings

Information regarding our legal proceedings can be found in Note 8, Commitments and Contingencies, to our accompanying condensed consolidated financial statements included in this report.

Item 1A. Risk Factors

We face many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock are described under Item 1A, Risk Factors, of our 2008 Form 10-K . This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC. There have been no material changes from the risk factors previously disclosed in our 2008 Form 10-K, except for the following.

Our oil and gas well drilling operations segment has historically received most of its revenue from the partnerships we sponsor. A reduction or loss of that business could reduce or eliminate the revenue, profit and cash flow associated with those activities; and, although reducing our business risk sharing inherent in drilling with partnership funds, would increase the risk of our business operations.

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Prior to 2008, our oil and gas well drilling operations segment received most of its revenue from the partnerships we sponsored. Historically, we have sponsored oil and natural gas partnerships through a network of non-affiliated Financial Industry Regulatory Authority registered broker dealers. We did not offer a partnership in 2008 or 2009 and do not anticipate offering a partnership in the future. However, if we wish to use partnerships to raise funds in future years, there can be no assurance that our network of brokers will be available or can be recreated. In that situation, our operations and profitability could be adversely affected. Furthermore, our shift away from the partnership business model has increased our risks, as the costs of drilling in new areas such as in the Marcellus will not be shared with partners. This could also adversely affect our profitability and operations.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers.

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total number of shares purchased (1)	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, 2009	120	$ 16.21	-	-
May 1-31, 2009	2,228	16.83	-	-
June 1-30, 2009	6,228	16.79	-	-
	8,576	16.79		

(1) Pursuant to our stock-based compensation plans, shares purchased during the quarter represent purchases from our executives and employees for their payment of tax liabilities related to the vesting of securities.

Item 3. Defaults Upon Senior Securities - None

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

The following provides a summary of votes cast for the proposals on which our shareholders voted at our annual meeting of shareholders held on June 5, 2009, in Denver, Colorado.

(1) To elect two director nominees:

Nominee	For	Withheld
Anthony J. Crisafio	13,279,708	414,915

Kimberly Luff Wakim	13,366,152	328,471

The following director terms continued after the annual meeting of shareholders.

Director	Term Expiring
Vincent F. D'Annunzio	2010
Larry F. Mazza	2010
Richard W. McCullough	2010
David C. Parke	2011
Jeffrey C. Swoveland	2011
Joseph E. Casabona	2011

(2) To ratify the selection of PricewaterhouseCoopers LLP as independent registered public accounting firm for the Company for the year ending December 31, 2009:

For	Against	Abstain
13,424,157	225,593	44,873

Item 5. Other Information - None

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Item 6. Exhibits Index

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
10.1*	2009 Base Salary and Short-Term Incentive Compensation Terms for Executive Officers.	8-K	000-07246		03/05/2009	
10.2*	2009 Long-Term Incentive Program for Executive Officers.	8-K	000-07246	10.1	03/05/2009	
10.3*	Non-Employee Director Compensation for the 2009-2010 Term.	8-K	000-07246		03/05/2009	
10.4*	2009 Short-Term Incentive Compensation Performance Criteria for Executive Officers.	8-K	000-07246		04/06/2009	
10.5*	Employment Agreement with R. Scott Meyers, Chief Accounting Officer, dated as of April 1, 2009.					X
10.6*	Separation Agreement with Eric R. Stearns, former Executive Vice President, dated May 19, 2009.					X
10.7	Sixth Amendment to Amended and Restated Credit Agreement dated as of May 22, 2009, by and amount the Company, certain of its subsidiaries, JP Morgan Chase Bank, N.A., and various other banks.	8-K	000-07246	10.1	05/29/2009	
10.8*	Amendment to Separation Agreement with Eric R. Stearns, former Executive Vice President, dated June 29, 2009.					X
12.1	Computation of Ratio of Earnings to Fixed Charges.					X
14.1	Code of Business Conduct and Ethics.					X
31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X

31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	X
32.1	Certifications by Chief Executive Officer and Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.	X

*Management contract or compensatory plan or arrangement.

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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 10, 2009

/s/ Richard W. McCullough
Richard W. McCullough
Chairman and Chief Executive Officer

/s/ Gysle R. Shellum
Gysle R. Shellum
Chief Financial Officer

/s/ R. Scott Meyers
R. Scott Meyers
Chief Accounting Officer