PETROLEUM DEVELOPMENT CORP
Form 10-Q
May 10, 2010

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 March 31, 2010

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 þ 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 filer ¨	Accelerated filer þ
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 þ

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 19,256,749 shares of the Company's Common Stock ($.01 par value) were outstanding as of April 30, 2010.

PETROLEUM DEVELOPMENT CORPORATION

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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 natural gas and oil 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 natural gas and oil;
- 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 ("U.S.");
- 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, 2009, filed with the Securities and Exchange Commission ("SEC") on March 4, 2010 ("2009 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.

REFERENCES

Unless the context otherwise requires, references to "PDC," "the Company," "we," "us," "our," "ours" or "ourselves" in this report refer to the registrant, Petroleum Development Corporation, together with its wholly owned subsidiaries, entities in which it has a controlling financial interest and its proportionate share of affiliated partnerships and PDC Mountaineer, LLC ("PDCM"), a joint venture with Lime Rock Partners.

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PART I - FINANCIAL INFORMATION

Item 1. Financial Statements

Petroleum Development Corporation
Condensed Consolidated Balance Sheets
(unaudited; in thousands, except share data)

	March 31, 2010	December 31, 2009*
Assets		
Current assets:		
Cash and cash equivalents	$26,460	$ 31,944
Restricted cash	2,491	2,490
Accounts receivable, net	52,467	56,491
Accounts receivable affiliates	9,983	7,956
Fair value of derivatives	48,157	42,223
Income tax receivable	27,816	27,728
Prepaid expenses and other current assets	4,734	8,538
Total current assets	172,108	177,370
Properties and equipment, net	963,894	1,008,193
Fair value of derivatives	47,475	20,228
Accounts receivable affiliates	16,453	15,473
Other assets	27,031	29,063
Total Assets	$1,226,961	$ 1,250,327
Liabilities and Equity		
Liabilities		
Current liabilities:		
Accounts payable	$42,844	$ 36,845
Accounts payable affiliates	13,830	13,015
Production tax liability	24,165	24,849
Fair value of derivatives	24,526	20,208
Funds held for distribution	27,679	28,256
Other accrued expenses	16,596	21,261
Total current liabilities	149,640	144,434
Long-term debt	259,729	280,657
Deferred income taxes	185,774	178,012
Asset retirement obligation	25,052	29,314
Fair value of derivatives	49,127	48,779
Accounts payable affiliates	14,262	5,996
Other liabilities	27,748	24,542
Total liabilities	711,332	711,734
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: 19,261,799 shares in 2010 and 19,242,219 in 2009	193	192
Additional paid-in capital	65,094	64,406
Retained earnings	450,353	426,629
Treasury shares, at cost; 8,273 shares in 2010 and 2009	(312)	(312)
Total shareholders' equity	515,328	490,915
Noncontrolling interest	301	47,678
Total equity	515,629	538,593
Total Liabilities and Equity	$1,226,961	$ 1,250,327

*Derived from audited 2009 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 March 31, 2010	2009
Revenues:		
Natural gas and oil sales	$60,368	$39,742
Sales from natural gas marketing	24,311	22,389
Commodity price risk management gain, net	43,222	23,683
Well operations, pipeline income and other	2,845	2,838
Total revenues	130,746	88,652
Costs and expenses:		
Natural gas and oil production and well operations costs	15,676	16,361
Cost of natural gas marketing	23,854	21,878
Exploration expense and impairment of natural gas and oil properties	6,418	5,643
General and administrative expense	10,694	12,094
Depreciation, depletion and amortization	28,389	34,360
Total costs and expenses	85,031	90,336
Gain on sale of leaseholds	-	120
Income (loss) from operations	45,715	(1,564)
Interest income	5	20
Interest expense	(7,800)	(8,383)
Income (loss) from continuing operations before income taxes	37,920	(9,927)
Provision (benefit) for income taxes	14,251	(4,095)
Income (loss) from continuing operations	23,669	(5,832)
Income from discontinued operations, net of tax	-	113
Net income (loss)	23,669	(5,719)
Less: net loss attributable to noncontrolling interest	(55)	(16)
Net income (loss) attributable to shareholders	$23,724	$(5,703)
Amounts attributable to shareholders:		
Income (loss) from continuing operations	$23,724	$(5,816)
Income from discontinued operations, net of tax	-	113
Net income (loss) attributable to shareholders	$23,724	$(5,703)
Earnings (loss) per share attributable to shareholders:		
Basic		
Income (loss) from continuing operations	$1.24	$(0.39)
Income from discontinued operations	-	0.01
Net income (loss) attributable to shareholders	$1.24	$(0.38)
Diluted		

Income (loss) from continuing operations	$1.23	$(0.39)
Income from discontinued operations	-	0.01
Net income (loss) attributable to shareholders	$1.23	$(0.38)
Weighted average common shares outstanding		
Basic	19,191	14,793
Diluted	19,287	14,793

See accompanying notes to condensed consolidated financial statements.

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Petroleum Development Corporation
Condensed Consolidated Statements of Cash Flows
(unaudited, in thousands)

	Three Months Ended March 31, 2010	2009
Cash flows from operating activities:		
Net income (loss)	$23,669	$(5,719)
Adjustments to net income (loss) to reconcile to cash provided by operating activities:		
Deferred income taxes	11,632	(6,688)
Depreciation, depletion and amortization	28,389	34,360
Exploratory dry hole costs	2,902	832
Amortization and impairment of unproved properties	600	614
Unrealized (gain) loss on derivative transactions	(20,490)	13,188
Other	2,627	3,154
Changes in assets and liabilities	2,016	(3,862)
Net cash provided by operating activities	51,345	35,879
Cash flows from investing activities:		
Capital expenditures	(32,581)	(73,697)
Deconsolidation effect on cash and cash equivalents	(3,074)	-
Other	16	120
Net cash used in investing activities	(35,639)	(73,577)
Cash flows from financing activities:		
Proceeds from credit facility	64,000	100,500
Repayment of credit facility	(85,000)	(72,500)
Payment of debt issuance costs	(23)	(45)
Excess tax benefits from stock-based compensation	74	-
Purchase of treasury stock	(241)	(75)
Net cash provided (used) by financing activities	(21,190)	27,880
Net decrease in cash and cash equivalents	(5,484)	(9,818)
Cash and cash equivalents, beginning of period	31,944	50,950
Cash and cash equivalents, end of period	$26,460	$41,132
Supplemental cash flow information:		
Cash payments for:		
Interest, net of capitalized interest	$7,067	$15,215
Income taxes, net of refunds	(33)	(2,364)
Non-cash investing activities:		
Change in accounts payable related to purchases of properties and equipment	6,056	(24,323)
Change in asset retirement obligation, with a corresponding increase to natural gas and oil properties, net of disposals	207	541

See Note 2 for non-cash transactions related to deconsolidation of PDCM

See accompanying notes to condensed consolidated financial statements.

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PETROLEUM DEVELOPMENT CORPORATION

Notes to Condensed Consolidated Financial Statements
March 31, 2010
(unaudited)

1. NATURE OF OPERATIONS AND BASIS OF PRESENTATION

We are a domestic independent natural gas and oil company engaged in the exploration for and the acquisition, development, production and marketing of natural gas and oil. As of March 31, 2010, we owned an interest in and operated approximately 5,000 gross wells located primarily in the Rocky Mountain Region and Appalachian Basin. We are engaged in two primary business segments: (1) natural gas and oil sales and (2) natural gas marketing.

The accompanying unaudited condensed consolidated financial statements include the accounts of PDC, our wholly owned subsidiaries, WWWV, LLC, an entity in which we have a controlling financial interest, and our proportionate share of PDCM and our affiliated partnerships. All material intercompany accounts and transactions have been eliminated in consolidation. We account for our investment in PDCM and our interests in natural gas and oil 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 34 entities which we proportionately consolidate. Our proportionate share of all significant transactions between us and these entities has been eliminated. See Note 2, Recent Adopted Accounting Standards — Consolidation, for the impact new accounting changes had on the consolidation of PDCM, a variable interest entity, as of January 1, 2010.

In our opinion, the accompanying financial statements contain all adjustments (consisting of only normal recurring adjustments) necessary for a fair presentation of our financial statements for interim periods in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, pursuant to such rules and regulations, certain notes and other financial information included in audited financial statements have been condensed or omitted. The information presented in this quarterly report on Form 10-Q should be read in conjunction with our audited consolidated financial statements and notes thereto included in our 2009 Form 10-K. Our accounting policies are described in the Notes to Consolidated Financial Statements in our 2009 Form 10-K and updated, as necessary, in this Form 10-Q. The results of operations for the three months ended March 31, 2010, 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.

We have evaluated our activities subsequent to March 31, 2010, and have concluded that no material subsequent events have occurred that would require recognition in the financial statements or disclosure in the notes to the financial statements.

2. RECENT ACCOUNTING STANDARDS

Recently Adopted Accounting Standards

Consolidation – Variable Interest Entities

In June 2009, the Financial Accounting Standards Board ("FASB") issued changes regarding an entity's analysis to determine whether any of its variable interests constitute controlling financial interests in a variable interest entity. This analysis identifies the primary beneficiary of a variable interest entity as the enterprise that has both of the following characteristics:

- the power to direct the activities of a variable interest entity that most significantly impact the entity's economic performance; and
- the obligation to absorb losses of the entity that could potentially be significant to the variable interest entity or the right to receive benefits from the entity that could potentially be significant to the variable interest entity.

Additionally, the entity is required to assess whether it has an implicit financial responsibility to ensure that a variable interest entity operates as designed when determining whether it has the power to direct the activities of the variable interest entity that most significantly impact the entity's economic performance. The guidance also requires ongoing reassessments of whether an enterprise is the primary beneficiary of a variable interest entity. We adopted these changes effective January 1, 2010. Upon adoption, we deconsolidated PDCM as power over the activities that significantly impact this joint venture is equally shared with our investment partner. No cumulative effect adjustment to retained earnings was recognized upon adoption.

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Notes to Condensed Consolidated Financial Statements
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(unaudited)

The following table presents the impact deconsolidation had on our balance sheet as of January 1, 2010, which effectively represents the noncontrolling interest portion, or 32.6%, of PDCM's consolidated assets and liabilities. Further, the changes below are non-cash items with the exception of the change in cash and cash equivalents, which is reflected in investing activities in the statement of cash flows. (in thousands)

	Decreased/(Increased)		Decreased/(Increased)
Assets		Liabilities and Equity	
Current assets		Current liabilities	
Cash and and cash equivalents	$ 3,074	Accounts payable	$ 813
Accounts receivable, net	1,335	Production tax liability	17
Accounts receivable affiliates	(2,399)	Fair value of derivatives	434
Prepaid expenses and other current assets	131	Total current liabilities	1,586
Total current assets	2,143	Fair value of derivatives	83
		Other liabilities	591
Properties and equipment, net of DD&A of $15,731	51,765	Asset retirement obligation	4,815
Fair value of derivatives	70	Total liabilities	7,075
Other assets	419	Noncontrolling interest	47,322
Total Assets	$ 54,397	Total Liabilities and Equity	$ 54,397

Fair Value Measurements and Disclosures

In January 2010, the FASB issued changes clarifying existing disclosure requirements related to fair value measurements. The update also added a new requirement to disclose fair value transfers in and out of Levels 1 and 2 and describe the reasons for the transfers. The adoption of these changes as of January 1, 2010, did not have a material impact on our financial statements.

Recently Issued Accounting Standards

Fair Value Measurements and Disclosures

In January 2010, the FASB issued changes related to fair value measurements requiring gross presentation of activities within the Level 3 roll forward, whereby entities must present separately information about purchases, sales, issuances and settlements. This change will be effective for our financial statements issued for annual reporting periods beginning after December 15, 2010. We do not expect the adoption of this change to have a material impact on our financial statements.

3. FAIR VALUE MEASUREMENTS

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 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, as of March 31, 2010, the impact of nonperformance risk on the fair value of our derivative assets and liabilities was not significant. Validation of our contracts' 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.

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(unaudited)

The following table presents, by hierarchy level, our derivative financial instruments, including both current and non-current portions, measured at fair value.

	March 31, 2010			December 31, 2009		
	Quoted Prices in Active Markets (Level 1)	Significant Unobservable Inputs (Level 3)	Total	Quoted Prices in Active Markets (Level 1)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)					
Assets:						
Commodity based derivatives	$69,436	$ 26,131	$95,567	$25,598	$ 36,796	$62,394
Basis protection derivative contracts	-	65	65	-	57	57
Total assets	69,436	26,196	95,632	25,598	36,853	62,451
Liabilities:						
Commodity based derivatives	(141)	(10,789)	(10,930)	(3,140)	(9,932)	(13,072)
Basis protection derivative contracts	-	(62,723)	(62,723)	-	(55,915)	(55,915)
Total liabilities	(141)	(73,512)	(73,653)	(3,140)	(65,847)	(68,987)
Net asset (liability)	$69,295	$ (47,316)	$21,979	$22,458	$ (28,994)	$(6,536)

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

	(in thousands)
Fair value, net liability, as of December 31, 2009	$ (28,994)
Changes in fair value included in statement of operations line item:	
Commodity price risk management, net	12,431
Sales from natural gas marketing	383
Cost of natural gas marketing	(3,293)
Changes in fair value included in balance sheet line item (1):	
Accounts receivable affiliates	(2,320)
Accounts payable affiliates	(4,538)
Settlements included in statement of operations line item:	
Commodity price risk management, net	(20,980)
Cost of natural gas marketing	(5)
Fair value, net liability, as of March 31, 2010	$ (47,316)

Changes in unrealized gains (losses) relating to assets (liabilities) still held as of March 31, 2010, included in statement of operations line item:		
Commodity price risk management gain, net	$	8,477
Sales from natural gas marketing		353
Cost of natural gas marketing		(3,604)
	$	5,226

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

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

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(unaudited)

Non-Derivative Assets and Liabilities. The carrying values of the financial instruments comprising current assets and current liabilities approximate fair value due to the short-term maturities of these instruments.

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 have not elected to account for the portion of our long-term debt related to our senior notes under the fair value option; however, we estimate the fair value of this portion of our long-term debt to be $215.2 million or 106% of par value as of March 31, 2010. We determined this valuation based upon measurements of trading activity.

We assess our natural gas and oil 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 natural gas and oil. 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 natural gas and oil 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.

We estimate the fair value of our plugging and abandonment obligations based on a discounted cash flows analysis. 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. Changes in estimated asset retirement obligations can result from revisions of estimated inflation rates, escalating retirement costs and changes in the estimated timing of settling asset retirement obligation. See Note 8, Asset Retirement Obligation, for changes in the fair value of our asset retirement obligations.

4. DERIVATIVE FINANCIAL INSTRUMENTS

As of March 31, 2010, we had derivative instruments in place for a portion of our anticipated production through 2013 for a total of 50,573,396 MMbtu of natural gas and 1,741,935 Bbls of oil. These derivative instruments were comprised of commodity collars and swaps, basis protection swaps and physical sales and purchases.

The following table summarizes the location and fair value amounts of our derivative instruments in the accompanying balance sheets.

Derivatives instruments not designated as hedges (1)		Balance sheet line item	Fair Value March 31, 2010	Fair Value December 31, 2009
			(in thousands)	
Derivative Assets:	Current			
	Commodity contracts			
	Related to natural gas and oil sales	Fair value of derivatives	$ 42,653	$ 39,107

	Related to natural gas marketing	Fair value of derivatives	5,452	3,077
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	52	39
			48,157	42,223
	Non Current			
	Commodity contracts			
	Related to natural gas and oil sales	Fair value of derivatives	46,986	19,680
	Related to natural gas marketing	Fair value of derivatives	476	530
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	13	18
			47,475	20,228
Total Derivative Assets (2)			$ 95,632	$ 62,451

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PETROLEUM DEVELOPMENT CORPORATION

Notes to Condensed Consolidated Financial Statements
March 31, 2010
(unaudited)

Derivatives instruments not designated as hedges (1)		Balance sheet line item	Fair Value March 31, 2010 (in thousands)	Fair Value December 31, 2009 (in thousands)
Derivative Liabilities:	Current			
	Commodity contracts			
	Related to natural gas and oil sales	Fair value of derivatives	$ (1,498)	$ (2,451)
	Related to natural gas marketing	Fair value of derivatives	(4,758)	(2,626)
	Basis protection contracts			
	Related to natural gas and oil sales	Fair value of derivatives	(18,270)	(15,127)
	Related to natural gas marketing	Fair value of derivatives	-	(4)
			(24,526)	(20,208)
	Non Current			
	Commodity contracts			
	Related to natural gas and oil sales	Fair value of derivatives	(4,243)	(7,572)
	Related to natural gas marketing	Fair value of derivatives	(431)	(423)
	Basis protection contracts			
	Related to natural gas and oil sales	Fair value of derivatives	(44,453)	(40,784)
			(49,127)	(48,779)
Total Derivative Liabilities (3)			$ (73,653)	$ (68,987)

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(1) As of March 31, 2010, and December 31, 2009, none of our derivative instruments were designated as hedges.

(2) Includes derivative positions that have been designated to our affiliated partnerships; accordingly, our accompanying balance sheets include a corresponding payable to our affiliated partnerships of $22.9 million and $13.4 million as of March 31, 2010, and December 31, 2009, respectively, representing their proportionate share of the derivative assets.

(3) Includes derivative positions that have been designated to our affiliated partnerships; accordingly, our accompanying balance sheets include a corresponding receivable from our affiliated partnerships of $22.9 million and $21 million as of March 31, 2010, and December 31, 2009, respectively, representing their proportionate share of the derivative liabilities.

The following table summarizes the impact of our derivative instruments on our accompanying statements of operations for the three months ended March 31, 2010 and 2009.

	Three Months Ended March 31,					
	2010			2009		
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)					
Commodity price risk management gain, net						
Realized gains	$21,067	$1,857	$22,924	$30,193	$6,433	$36,626
Unrealized gains (losses)	(21,067)	41,365	20,298	(30,193)	17,250	(12,943)
Total commodity price risk management gain, net (1)	$-	$43,222	$43,222	$-	$23,683	$23,683
Sales from natural gas marketing						
Realized gains	$752	$233	$985	$2,109	$259	$2,368
Unrealized gains	(752)	4,264	3,512	(2,109)	2,934	825
Total sales from natural gas marketing(2)	$-	$4,497	$4,497	$-	$3,193	$3,193
Cost of natural gas marketing						
Realized gains (losses)	$(774)	$532	$(242)	$(1,970)	$1,663	$(307)
Unrealized losses	774	(4,094)	(3,320)	1,970	(3,040)	(1,070)
Total cost of natural gas marketing(2)	$-	$(3,562)	$(3,562)	$-	$(1,377)	$(1,377)

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

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PETROLEUM DEVELOPMENT CORPORATION

Notes to Condensed Consolidated Financial Statements
March 31, 2010
(unaudited)

Concentration of Credit Risk. A significant component of our future liquidity is concentrated in derivative instruments that enable us to manage a portion of our exposure to price volatility from producing natural gas and oil. These arrangements expose us to credit risk of nonperformance by our counterparties. We primarily use financial institutions, who are also major lenders in our credit facility agreement, as counterparties to our derivative contracts. To date, we have had no counterparty default losses.

The following table presents the counterparties that expose us to credit risk as of March 31, 2010, with regard to our derivative assets.

Counterparty Name	Fair Value of Derivative Assets March 31, 2010 (in thousands)
JPMorgan Chase Bank, N.A. (1)	$ 50,240
Calyon (1)	20,996
Wachovia (1)	13,661
Various (2)	10,735
Total	$ 95,632

(1) Major lender in our credit facility, see Note 7, Long-Term Debt.
(2) Represents a total of 50 counterparties, including four lenders in our credit facility.

5. PROPERTIES AND EQUIPMENT

The following table presents the components of properties and equipment, net.

	March 31, 2010	December 31, 2009
	(in thousands)	
Natural gas and oil properties (successful efforts method of accounting)		
Proved	$ 1,294,959	$ 1,329,666
Unproved	35,080	38,626
Total natural gas and oil properties	1,330,039	1,368,292
Pipelines and related facilities	35,440	38,202
Transportation and other equipment	31,625	33,624

Land and buildings		14,229		14,699
Construction in progress		20,247		9,131
		1,431,580		1,463,948
Accumulated DD&A		(467,686)		(455,755)
Properties and equipment, net (1)	$	963,894	$	1,008,193

(1) As a result of the deconsolidation of PDCM, properties and equipment were reduced by $51.8 million, net of accumulated depreciation, depletion and amortization ("DD&A") of $15.7 million, from December 31, 2009. See Note 2, Recent Accounting Standards.

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The following table presents the capitalized exploratory well costs pending determination of proved reserves and included in properties and equipment on the balance sheets.

	Amount (in thousands)	Number of Wells
Balance at December 31, 2009	$ 1,174	2
Deconsolidation of PDCM	(340)	-
Additions to capitalized exploratory well costs pending the determination of proved reserves	4,009	2
Reclassifications to proved natural gas and oil properties based on the determination of proved reserves	(567)	(1)
Balance at March 31, 2010	$ 4,276	3

As of March 31, 2010, 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.

6. 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. A tax expense or benefit unrelated to the current year ordinary income or loss is recognized in its entirety as a discrete item of tax in the period identified. 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 effective tax rate for the three months ended March 31, 2010, was 37.5% (provision on income) compared to 41.3% (benefit on a loss) for the same prior year period. The loss realized for the three months ended March 31, 2009, exceeded our projected loss for the year. As a result, we calculated our 2009 first quarter tax benefit by multiplying the 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 2009 first quarter by $1.6 million. No similar limitation calculation was required for the three months ended March 31, 2010. There were no significant discrete items recorded in the first quarter of 2009 or 2010.

As of March 31, 2010, we had a gross liability for uncertain tax benefits of $0.8 million, which is substantially unchanged from the December 31, 2009, liability. If recognized, $0.8 million of this liability would affect our effective tax rate. This liability is reflected in federal and state income taxes payable in our accompanying balance sheet. The Internal Revenue Service ("IRS") is expected to begin an examination of our 2007, 2008 and 2009 tax years in May 2010. Therefore, we expect the liability for uncertain tax benefits to decrease during the next twelve-month period as items are either resolved without change or converted to amounts due to the IRS.

As of the date of this filing, we are current with our income tax filings in all applicable state jurisdictions and currently have no state income tax returns in the process of examination.

7. LONG-TERM DEBT

The following table presents the components of long-term debt.

	March 31, 2010	December 31, 2009
	(in thousands)	
Credit facility	$ 59,000	$ 80,000
12% Senior notes due 2018, net of discount of $2.3 million	200,729	200,657
Total long-term debt	$ 259,729	$ 280,657

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Credit facility

We have a credit facility arranged by JPMorgan Chase Bank, N.A., dated as of November 4, 2005, as amended last on December 18, 2009 ("the Eighth Amendment"), with an aggregate revolving commitment of $305 million, which expires on May 22, 2012. The credit facility, through the series of amendments, includes commitments from twelve additional banks. The maximum allowable commitment under the credit facility is $500 million. The credit facility is guaranteed by the Company and its existing subsidiaries, with the exception of certain immaterial subsidiaries, individually and in the aggregate. All of our subsidiaries are wholly owned. The guarantee of the Company's subsidiaries are full and unconditional and joint and several. The credit facility is subject to and collateralized by our natural gas and oil reserves, exclusive of PDCM's natural gas and oil 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 May and November based upon a quantification of 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 determined by our lenders, is utilized to quantify the reserves used in the borrowing base calculation and thus determines the underlying borrowing base. On May 5, 2010, our redetermination, based on our December 31, 2009, reserves, was completed and our aggregate revolving commitment of $305 million was reaffirmed. We have an $18.7 million irrevocable standby letter of credit in favor of a third party transportation service provider. This letter of credit reduces the amount of available funds under our credit facility by an equal amount. We pay a fronting fee of 0.25% per annum and an additional quarterly maintenance fee equivalent to the spread over Eurodollar loans (2.5% as of March 31, 2010) for the period the letter of credit remains outstanding. The letter of credit expires on May 22, 2012.

As of March 31, 2010, we had $5.6 million in debt issuance costs being amortized at a rate of $0.7 million per quarter. As of March 31, 2010, the available funds under our credit facility were $227.3 million. The borrowing rate on our outstanding balance at March 31, 2010, was 5.8% per annum compared to 4.7% per annum at December 31, 2009. We were in compliance with all covenants at March 31, 2010, and expect to remain in compliance throughout the next year.

12% Senior Notes Due 2018

In February 2008, we issued 12% senior notes with a total principal amount of $203 million 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 discount, 98.572% of the principal amount. The original discount and the deferred note issuance costs are being amortized to interest expense over the term of the debt using the effective interest method. As of March 31, 2010, we had $6.6 million in discount and costs being amortized at a rate of $0.2 million per quarter. We were in compliance with all covenants as of March 31, 2010, and expect to remain in compliance throughout the next year.

8. ASSET RETIREMENT OBLIGATION

The following table presents the changes in carrying amounts of the asset retirement obligation associated with our working interest in natural gas and oil properties.

		Amount (in thousands)
Balance at December 31, 2009	$	29,564
Deconsolidation of PDCM		(4,815)
Obligations incurred with development activities		223
Accretion expense		346
Obligations charged with disposal of properties and asset retirements		(16)
Balance at March 31, 2010		25,302
Less current portion		(250)
Long-term portion	$	25,052

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9. COMMITMENTS AND CONTINGENCIES

Firm Transportation Agreements

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. Satisfaction of the volumes requirements include volumes produced by us, volumes purchased from third parties and volumes produced by our affiliated partnerships. As of March 31, 2010, based on a review of our drilling plans and volume projections, we do not expect to meet all future volume requirements for a firm transportation agreement in our Piceance Basin. Accordingly, as of March 31, 2010, we have a related liability in the amount of $2.8 million, previously recorded in prior periods, included in other liabilities on the balance sheet. We are currently working with the third party to renegotiate the terms and timing of our volume requirements under this agreement. If we are not able to renegotiate this agreement or meet all future volume requirements, an additional liability may result.

The following table presents gross volume information related to our long-term firm sales, processing and transportation agreements for pipeline capacity. 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.

		For the Twelve Months Ending March 31,					
Area	Total	2011	2012	2013	2014	Thereafter	Expiration Date
Volume (MMbtu)							
Appalachian Basin (1)	111,316,620	745,400	591,300	6,671,120	10,993,800	92,315,000	August 2022
Piceance	216,126,038	31,836,523	32,465,696	32,872,393	29,398,697	89,552,729	May 2021
NECO	1,375,000	1,375,000	-	-	-	-	December 2010
NECO	12,330,000	1,825,000	1,825,000	1,825,000	1,825,000	5,030,000	December 2016
Total	341,147,658	35,781,923	34,881,996	41,368,513	42,217,497	186,897,729	
Dollar commitment (in thousands)	$175,318	$18,321	$18,072	$21,417	$21,841	$95,667	

(1) Includes a precedent agreement that becomes effective when the planned pipeline is placed in service, currently estimated to be September 2012 and represents 92.5%, 96.7% and 97% of the total MMbtu presented for the twelve months ending March 31, 2013, 2014 and thereafter, respectively. This agreement will be null and void if the pipeline is not completed. In August 2009, we issued a letter of credit related to this agreement; see Note 7, Long-Term Debt.

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.

Royalty Owner Class Action

Gobel et al v. Petroleum Development Corporation, Case No. 09-C-40 in U. S. District Court, Northern District of West Virginia, filed on January 27, 2009

David W. Gobel, individually and as representative of the class of all similarly situated individuals and entities, filed a lawsuit against the Company alleging that we failed to properly pay royalties (the "Gobel lawsuit"). 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. The stay in effect as of December 31, 2009, lapsed in February 2010. The parties have filed briefs on Gobel's Motion to Remand to state court. We are awaiting a ruling from the court on that motion.

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Other

In July 2008, the Company self-reported to the Colorado Department of Public Health and Environment (the "CDPHE") certain non-compliance with air laws at a compressor station in the Piceance Basin. The CDPHE subsequently initiated a review and inspection of air compliance at this station. On November 18, 2009, and December 19, 2009, the Company received related compliance advisories for alleged non-compliance. On February 19, 2010, the Company received a letter from the CDPHE with a proposed settlement for this matter of $0.2 million, which was accrued and included in natural gas and oil production and well operations costs for the three months ended March 31, 2010. The Company has entered negotiations with the CDPHE regarding this assessment and continues to work to bring this matter to closure.

On December 8, 2008, we received a Notice of Violation/Cease and Desist Order (the "Notice") from the CDPHE, 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 natural gas and oil companies operating in the Piceance region of Colorado. Operating expenses, including this fine, if any, are allocated among the 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. Commencing in December 2009, the Company entered negotiations with the CDPHE regarding this notice and continues to work to bring this matter to closure. Given 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.

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 from production), if repurchase is requested by investors, subject to our financial ability to do so. As of March 31, 2010, the maximum annual repurchase obligation, based upon the minimum price described above, was approximately $9.2 million. We believe we have adequate liquidity to meet this obligation. During the first quarter of 2010, the repurchases of partnership units pursuant to this provision were immaterial.

Employment Agreements with Executive Officers

We have employment agreements with our Chief Executive Officer, Chief Financial 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 the executive's highest annual base salary during the previous two years of employment immediately preceding the termination date and the executive's highest annual bonus paid or payable during the same two year period. For one executive, in this calculation, the target bonus will be used as the minimum value for the first two years of employment. 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, with some differences. The executive officer is also entitled to (i) vesting of any unvested equity compensation (excluding all long-term 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, in the case of our Chief Executive Officer and General Counsel and Corporate Secretary, 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.

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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.

Derivative Contracts

We would be exposed to natural gas and oil 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 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.

10. STOCK-BASED COMPENSATION PLANS

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 March 31,	
	2010	2009 (1)
	(in thousands)	
Total stock-based compensation expense	$ 1,005	$ 1,639
	(386)	(625)

Income tax benefit		
Net income impact	$ 619	$ 1,014

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(1) Includes $0.5 million related to an agreement with our former chief executive officer.

11. EARNINGS PER SHARE

The following is a reconciliation of weighted average diluted shares outstanding.

	Three Months Ended March 31, 2010	2009
	(in thousands)	
Weighted average common shares outstanding - basic	19,191	14,793
Dilutive effect of stock-based compensation:		
Unamortized portion of restricted stock	88	-
Non employee director deferred compensation	8	-
Weighted average common shares outstanding - diluted	19,287	14,793

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For the three months ended March 31, 2009, the weighted average common shares outstanding for both basic and diluted were the same because the effect of dilutive securities was anti-dilutive due to our net loss for the period. 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 March 31,	
	2010	2009
	(in thousands)	
Weighted average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:		
Unamortized portion of restricted stock	146	260
Stock options	10	18
Non employee director deferred compensation	-	7
Total anti-dilutive common share equivalents	156	285

12. NONCONTROLLING INTEREST

WWWV, LLC

In 2007, we contributed $0.8 million for a 50% interest in WWWV, LLC (the "LLC"), a limited liability company for which we serve as the managing member. The LLC's only asset is an aircraft and the LLC was formed for the purpose of owning and operating the aircraft. We consolidate the entity based on a controlling financial interest. We have commenced activities to divest the asset and dissolve the entity, which will not have a material impact on our financial statements.

PDCM

In October 2009, we entered into a joint venture arrangement to form PDCM. At that time, the joint venture was determined to be a variable interest entity due to the disproportionate voting rights compared to the ownership rights; accordingly, we consolidated the joint venture as we were the primary beneficiary as of and for the period ended December 31, 2009. As of January 1, 2010, pursuant to the adoption of new accounting changes related to variable interest entities, the joint venture was deconsolidated and is now accounted for on a proportionate share basis. See Note 2, Recent Accounting Standards.

The following table presents the changes in noncontrolling interest.

	Amount (in thousands)
Balance at December 31, 2009	$ 47,678

Deconsolidation of PDCM		(47,322)
Net loss attributable to noncontrolling interest		(55)
Balance at March 31, 2010	$	301

13. TRANSACTIONS WITH AFFILIATES

We enter into derivative instruments for our own production as well as for our 33 affiliated partnerships' production. As of March 31, 2010, we had a due to affiliates of $22.9 million representing their designated portion of the fair value of our gross derivative assets and a due from affiliates of $22.9 million representing their designated portion of the fair value of our gross derivative liabilities.

Our natural gas marketing segment manages the marketing of natural gas for PDCM and our affiliated partnerships with production in the Appalachian Basin, and in the case of our affiliated partnerships in Michigan. Our sales from natural gas marketing include $0.9 million and $1 million for the three months ended March 31, 2010, related to the marketing of natural gas on behalf of PDCM and our affiliated partnerships, respectively. For the three months ended March 31, 2009, sales from natural gas marketing include $1 million related to the marketing of natural gas on behalf of our affiliated partnerships.

We provide well operations and pipeline services to our affiliated partnerships. The majority of our revenue and expenses related to well operations and pipeline income are associated with services provided to our affiliated partnerships.

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We provide certain well operating and administrative services for PDCM. Amounts billed to PDCM related to these services were $2.9 million for the three months ended March 31, 2010. Included in our statement of operations is our proportionate share of the $2.9 million. Natural gas and oil production and well operations costs, exploration expense and impairment of natural gas and oil properties and general and administrative expense in the statement of operations reflect $1 million, $0.3 million and $0.7 million, respectively, related to these services.

14. BUSINESS SEGMENTS

We separate our operating activities into two segments: natural gas and oil sales and natural gas marketing. All material inter-company accounts and transactions between segments have been eliminated.

The following tables present our segment information, reclassified for discontinued operations.

	Three Months Ended March 31, 2010	2009
	(in thousands)	
Revenues:		
Natural gas and oil sales	$ 106,432	$ 66,221
Natural gas marketing	24,311	22,389
Unallocated	3	42
Total	$ 130,746	$ 88,652
Segment income (loss) before income taxes:		
Natural gas and oil sales	$ 56,805	$ 10,713
Natural gas marketing	450	514
Unallocated	(19,335)	(21,154)
Total	$ 37,920	$ (9,927)

	March 31, 2010	December 31,2009
	(in thousands)	
Segment assets:		
Natural gas and oil sales	$ 1,135,098	$ 1,152,160
Natural gas marketing	19,297	22,614
Unallocated	72,566	75,553
Total	$ 1,226,961	$ 1,250,327

PETROLEUM DEVELOPMENT CORPORATION

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

Non-GAAP Financial Measures

We use "adjusted cash flow from operations," "adjusted net income attributable to shareholders" and "adjusted EBITDA," non-GAAP financial measures, for internal managerial purposes, when evaluating period-to-period comparisons and providing public guidance on possible future results. These measures are not measures of financial performance under GAAP and should be considered in addition to, not as a substitute for, net income attributable to shareholders, cash flows from operations, investing, or financing activities. These measures should not be used as liquidity measures or indicators of cash flows reported in accordance with U.S. GAAP. The non-GAAP financial measures that we use may not be comparable to similarly titled measures reported by other companies. Also, in the future, we may disclose different non-GAAP financial measures in order to help our investors more meaningfully evaluate and compare our future results of operations to our previously reported results of operations. We strongly encourage investors to review our financial statements and publicly filed reports in their entirety and to not rely on any single financial measure. See Reconciliation of Non-GAAP Financial Measures below for a detailed description of these measures as well as a reconciliation of each to the nearest GAAP measure.

Overview

Natural gas and oil sales increased 51.9% or $20.6 million for the first quarter of 2010 compared to the first quarter of 2009, even though production volumes decreased 18.8% quarter-over-quarter. This increase was driven primarily by the improved commodity price environment and the increase in our oil production as a percentage of our total production. Average sales price per Mcfe, excluding the impact of realized derivative gains and the provision for underpayment of natural gas sales, was $6.67 for the current year quarter compared to $3.79 for the same quarter a year ago. Although down 37.4% from the first quarter of 2009, realized derivative gains from natural gas and oil sales contributed an additional $2.53 per Mcfe or $22.9 million to the first quarter of 2010 total revenues. Comparatively, the total per Mcfe price realized, consisting of the average sales price and realized derivative gains, increased 29.9% to $9.20 for the current year quarter from $7.08 for the same prior year quarter.

The increase in total revenues did not have a corresponding impact on costs and expenses as natural gas and oil production and well operations costs and general and administrative expense decreased by $0.7 million and $1.4 million, respectively, for the current year quarter compared to the same prior year quarter. It is our intent to continue to maintain such a spending discipline.

The improved commodity price environment and the decreased costs and expenses were the major contributors to our improved cash flows from operations, increasing from $35.9 million for the prior year quarter to $51.3 million for the current year quarter or 42.9% quarter-over-quarter. Our positive operating cash flows allowed us the opportunity to further pay down our outstanding draw on our credit facility by $21 million.

During the first quarter of 2010, our liquidity position showed continued improvement as the availability under our credit facility increased to $227.3 million and cash and cash equivalents remained stable at $26.5 million for a total liquidity position of $253.8 million at March 31, 2010, compared to $238.2 million at December 31, 2009. We believe that our positive operating results coupled with our liquidity position provide us with flexibility and stability to capitalize on future opportunities and lessen the impact of unforseen challenges.

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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, natural gas and oil sales, average sales price received, average sales price including realized derivative gains, average lifting cost, other operating income and expenses.

	Three Months Ended March 31,		
	2010	2009	Change
	(dollars in thousands, except per unit data)		
Production (1)			
Natural gas (Mcf)	7,274,527	9,090,261	-20.0 %
Oil (Bbls)	296,678	343,884	-13.7 %
Natural gas equivalent (Mcfe) (2)	9,054,595	11,153,565	-18.8 %
Mcfe per day	100,607	123,929	
Natural Gas and Oil Sales			
Natural gas	$38,548	$29,334	31.4 %
Oil	21,820	12,989	68.0 %
Provision for underpayment of natural gas sales	-	(2,581)	100.0 %
Total natural gas and oil sales	$60,368	$39,742	51.9 %
Realized Gain on Derivatives, net (3)			
Natural gas	$20,879	$29,332	-28.8 %
Oil	2,045	7,294	-72.0 %
Total realized gain on derivatives, net	$22,924	$36,626	-37.4 %
Average Sales Price (excluding gains/losses on derivatives)			
Natural gas (per Mcf)	$5.30	$3.23	64.1 %
Oil (per Bbl)	$73.55	$37.77	94.7 %
Natural gas equivalent (per Mcfe)	$6.67	$3.79	76.0 %
Average Sales Price (including realized gains/losses on derivatives)			
Natural gas (per Mcf)	$8.17	$6.45	26.7 %
Oil (per Bbl)	$80.44	$58.98	36.4 %
Natural gas equivalent (per Mcfe)	$9.20	$7.08	29.9 %
Average Lifting Cost (per Mcfe) (4)	$1.04	$0.93	11.8 %
Natural gas marketing (5)	$457	$511	-10.6 %
Other Costs and Expenses			
Exploration expense and impairment of natural gas and oil properties	$6,418	$5,643	13.7 %
General and administrative expense	$10,694	$12,094	-11.6 %
Depreciation, depletion and amortization	$28,389	$34,360	-17.4 %
Interest Expense	$7,800	$8,383	-7.0 %

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) Amounts represent realized derivative gains and losses related to natural gas and oil sales; the amounts do not include realized derivative gains and losses related to natural gas marketing.
(4) Lifting costs represent natural gas and oil operating expenses, which exclude production taxes.
(5) Represents sales from natural gas marketing less cost of natural gas marketing.

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Natural Gas and Oil Sales

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

	Three Months Ended March 31,		
	2010	2009	Percentage Change
Production			
Natural gas (Mcf)			
Rocky Mountain Region	6,275,218	7,788,034	-19.4 %
Appalachian Basin (1)	630,510	975,681	-35.4 %
Other	368,799	326,546	12.9 %
Total	7,274,527	9,090,261	-20.0 %
Oil (Bbls)			
Rocky Mountain Region	294,876	341,183	-13.6 %
Appalachian Basin (1)	722	1,704	-57.6 %
Other	1,080	997	8.3 %
Total	296,678	343,884	-13.7 %
Natural gas equivalent (Mcfe)			
Rocky Mountain Region	8,044,474	9,835,132	-18.2 %
Appalachian Basin (1)	634,842	985,905	-35.6 %
Other	375,279	332,528	12.9 %
Total	9,054,595	11,153,565	-18.8 %

(1) Approximately 84.4%, 11.1% and 83.1%, of the decrease in natural gas, oil and natural gas equivalent, respectively, was the result of our contribution of natural gas and oil properties to PDCM.

	Three Months Ended March 31,		
	2010	2009	Percentage Change
Average Sales Price (excluding derivative gains/losses)			
Natural gas (per Mcf)			
Rocky Mountain Region	$ 5.32	$ 2.94	81.0 %
Appalachian Basin	5.34	5.04	6.0 %
Other	4.87	4.22	15.4 %
Weighted average price	5.30	3.23	64.1 %
Oil (per Bbl)			
Rocky Mountain Region	73.52	37.78	94.6 %
Appalachian Basin	79.18	37.06	113.7 %
Other	76.81	36.29	111.7 %
Weighted average price	73.55	37.77	94.7 %
Natural gas equivalent (per Mcfe)			
Rocky Mountain Region	6.84	3.65	87.4 %
Appalachian Basin	5.39	5.04	6.9 %

Other	5.01	4.25	17.9	%
Weighted average price	6.67	3.79	76.0	%

Despite decreases in production for the first quarter of 2010, natural gas and oil sales revenue for this period, excluding the provision for underpayment of gas sales, increased $18 million, compared to the same 2009 period. Approximately $26.1 million of the increase in natural gas and oil sales revenue for the 2010 three-month period was due to pricing, offset in part by decreased production, which reduced natural gas and oil sales by $8 million.

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Natural Gas and Oil Pricing. Our results of operations depend upon many factors, particularly the price of natural gas and oil and our ability to market our production effectively. Natural gas and oil prices are among the most volatile of all commodity prices. These price variations have a material impact on our financial results. Natural gas prices vary by region and locality, depending upon the distance to markets, and the supply and demand relationships in that region or locality and the availability of sufficient pipeline capacity. This can be especially true in the Rocky Mountain Region. The combination of increased drilling activity and the lack of local markets has 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 driven predominantly by global supply and demand relationships.

The price we receive for our natural gas produced in the Rocky Mountain Region is based on a market basket of prices, which generally includes gas sold at Colorado Interstate Gas ("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 New York Mercantile Exchange ("NYMEX") -based. This negative differential has narrowed in recent months and for two out of the last six months became a slight positive differential, which is inconsistent with historical variances. This negative differential between NYMEX and CIG averaged $1.62 for the three months ended March 31, 2009, and narrowed to an average of $0.16 for the three months ended March 31, 2010. Along with the higher sales price of natural gas liquids, which sales are included in our natural gas sales, the price we realized in the Rocky Mountain Region exceeded the NYMEX index price for the first quarter of 2010.

The table below identifies the market for our natural gas and oil sales based on production for the first quarter of 2010. The pricing basis is the index that most closely relates to the price under which our natural gas and oil was sold.

Energy Market Exposure
For the Three Months Ended March 31, 2010

Area	Market	Commodity	Percent of Production
Rocky Mountain Region			
Piceance/Wattenberg	Colorado Interstate Gas	Gas	40%
Colorado/North Dakota	NYMEX	Oil	20%
Piceance	San Juan Basin/Southern California	Gas	15%
NECO	Mid Continent (Panhandle Eastern)	Gas	9%
Wattenberg	Colorado Liquids	Gas	4%
Total Rocky Mountain Region			88%
Appalachian Basin	NYMEX	Gas	7%
Other	Other	Gas/Oil	5%
			100%

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

	Three Months Ended March 31,	
	2010	2009
	(in thousands)	
Lease operating expenses	$ 9,452	$ 10,321
Production taxes	2,429	1,913
Costs of well operations and pipeline income	1,932	1,643
Overhead and other production expenses	1,863	2,484
Total natural gas and oil production and well operations costs	$ 15,676	$ 16,361

Lease operating expenses. Lifting costs per Mcfe increased 11.8% to $1.04 per Mcfe for the first quarter of 2010 from $0.93 per Mcfe for the same period in 2009. The increased per Mcfe costs are primarily due to a decrease in production volumes of 18.8%, which results in the fixed cost portion of our lease operating expenses being absorbed by a reduced number of units.

Production taxes. Production taxes increased $0.5 million or 27% to $2.4 million in the first quarter of 2010 compared to the same period in 2009. Production taxes vary directly with natural gas and oil sales.

Costs of well operations and pipeline income. The increases in cost of well operations and pipeline income for the first quarter of 2010 compared to same period in 2009 were the result of increased costs related to pipeline and compressor expenses.

Commodity Price Risk Management, Net

Commodity price risk management, net includes realized gains and losses and unrealized changes in the fair value of derivative instruments related to our natural gas and oil production. Commodity 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 our accompanying financial statements included in this report for additional details of our derivative financial instruments.

The following table presents the realized and unrealized derivative gains and losses included in commodity price risk management, net.

	Three Months Ended March 31,	
	2010	2009
	(in thousands)	
Commodity price risk management gain, net:		
Realized gains:		
Natural gas	$ 20,879	$ 29,332
Oil	2,045	7,294
Total realized gain, net	22,924	36,626
Unrealized gains (losses):		
Reclassification of realized gains included in prior periods unrealized	(21,067)	(30,193)
Unrealized gains for the period	41,365	17,250
Total unrealized gain (loss), net	20,298	(12,943)
Total commodity price risk management gain, net	$ 43,222	$ 23,683

Realized gains recognized in the first quarter of 2010 of $22.9 million are a result of lower natural gas and oil spot prices at settlement compared to the respective strike price. During the first quarter of 2010, we recorded unrealized gains of $41.8 million, $45.4 million of which was related to our natural gas positions, offset in part by unrealized losses on our CIG basis swaps of $4.4 million as the forward basis differential between NYMEX and CIG had continued to narrow.

During the first quarter of 2009, we experienced both realized and unrealized derivative gains as natural gas and oil prices declined. The net unrealized gain for the first quarter of 2009 of $17.3 million comprised of $33 million net unrealized gain from our commodity derivatives offset in part by a decrease in fair value of our CIG basis swaps of $15.7 million.

Natural Gas and Oil Sales Derivative Instruments. We use various derivative instruments to manage fluctuations in natural gas and oil prices. We have in place a variety of collars, fixed-price swaps and basis swaps on a portion of our estimated natural gas and oil 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 commodity 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. Under our basis protection swaps, if the differential widens beyond the basis swap price, then the counterparty pays us; however, if the differential narrows, then we pay the counterparty. Because we sell all of our physical natural gas and oil at similar prices to the indexes inherent in our derivative instruments, we ultimately realize a price for our hedged production related to our collars of no less than the floor and no more than the ceiling and, for our commodity swaps, we ultimately realize the fixed price related to our swaps.

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The following table presents our derivative positions (including our proportionate share of the derivative positions designated to our affiliated partnerships) in effect as of March 31, 2010, related to natural gas and oil production by area.

	Collars			Fixed-Price Swaps		CIG Basis Protection Swaps		
Commodity/Operating Area/Index	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price Floors	Weighted Average Contract Price Ceilings	Quantity (Gas-MMbtu Oil-Bbls)	Weighted Average Contract Price	Quantity (Gas-MMbtu)	Weighted Average Contract Price	Fair Value At March 31, 2010 (1) (in thousands)
Natural Gas								
Rocky Mountain Region								
CIG								
04/01 - 06/30/2010	-	$-	$-	540,049	$5.05	-	$-	$792
07/01 - 09/30/2010	-	-	-	392,505	5.05	-	-	474
10/01 - 12/31/2010	680,333	4.75	9.45	234,319	5.05	-	-	602
01/01 - 03/31/2011	1,020,500	4.75	9.45	187,211	5.81	-	-	623
04/01 - 12/31/2011	-	-	-	772,532	5.81	-	-	685
PEPL								
04/01 - 06/30/2010	300,000	5.00	8.90	575,081	5.87	-	-	1,604
07/01 - 09/30/2010	300,000	5.00	8.90	526,993	5.93	-	-	1,362
10/01 - 12/31/2010	360,000	5.55	9.38	427,624	5.95	-	-	1,083
01/01 - 03/31/2011	390,000	5.76	9.56	271,628	6.18	-	-	698
04/01 - 12/31/2011	-	-	-	1,845,796	6.18	-	-	1,987
2012 - 2013	-	-	-	2,346,224	6.18	-	-	1,357
NYMEX								
04/01 - 06/30/2010	152,202	5.85	10.15	3,055,521	6.01	2,637,126	(1.88)	2,799
07/01 - 09/30/2010	152,202	5.85	10.15	2,968,781	6.02	2,541,873	(1.88)	1,989
10/01 - 12/31/2010	569,021	5.94	9.15	1,758,151	6.66	1,794,148	(1.88)	1,719
01/01 - 03/31/2011	724,519	5.96	9.10	930,869	7.47	1,200,555	(1.88)	877
04/01 - 12/31/2011	-	-	-	6,773,184	6.89	6,468,850	(1.88)	1,174
2012 - 2013	8,785,163	6.05	8.43	7,408,635	7.08	14,612,635	(1.88)	(5,584)
Appalachia								
NYMEX								
04/01 - 06/30/2010	7,131	5.85	10.15	465,737	5.34	-	-	684
07/01 - 09/30/2010	7,131	5.85	10.15	448,887	5.34	-	-	542
10/01 - 12/31/2010	7,205	6.45	11.48	440,313	5.35	-	-	273
01/01 - 03/31/2011	8,401	6.61	11.60	419,852	6.37	-	-	434

04/01 - 12/31/2011	-	-	-	1,215,981	6.37	-	-	1,239
2012 - 2013	-	-	-	71,639	7.24	-	-	89
Michigan								
NYMEX								
04/01 - 06/30/2010	73,272	5.85	10.15	185,056	6.70	-	-	662
07/01 - 09/30/2010	73,272	5.85	10.15	181,060	6.73	-	-	593
10/01 - 12/31/2010	73,191	6.45	11.47	169,899	6.80	-	-	483
01/01 - 03/31/2011	83,786	6.62	11.64	72,154	8.85	-	-	383
04/01 - 12/31/2011	-	-	-	616,542	7.44	-	-	1,277
2012 - 2013	427,363	6.05	8.43	1,076,481	7.17	-	-	1,570
Total Natural Gas	14,194,692			36,378,704		29,255,187		22,470
Oil								
Rocky Mountain Region								
NYMEX								
04/01 - 06/30/2010	-	-	-	171,197	90.42	-	-	1,052
07/01 - 09/30/2010	-	-	-	155,188	91.42	-	-	982
10/01 - 12/31/2010	-	-	-	142,062	92.30	-	-	957
01/01 - 03/31/2011	67,814	73.00	99.80	92,607	74.29	-	-	(1,001)
04/01 - 12/31/2011	163,638	73.00	99.80	263,281	73.75	-	-	(3,109)
2012 - 2013	686,148	75.00	102.63	-	-	-	-	(204)
Total Oil	917,600			824,335		-		(1,323)
Total Natural Gas and Oil								$21,147

(1) Approximately 35% of the fair value of our derivative assets and 100% of our derivative liabilities were measured using significant unobservable inputs (Level 3), see Note 3, Fair Value Measurements, to the accompanying financial statements.

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Natural Gas Marketing

The increase in sales from natural gas marketing in the first quarter of 2010 compared to the same period in 2009 is primarily due to an increase in prices and increased unrealized gains on derivative instruments, offset in part by a decrease in realized gains on derivatives. In the first quarter of 2010, prices on sales were 4.5% higher on average than in the same period for 2009, resulting in a $0.8 million increase in sales. In the first quarter of 2010, unrealized derivative gains on sales contracts increased $2.7 million from $0.8 million in the same period in 2009 to $3.5 million in the first quarter of 2010. This unrealized gain was partially offset by a decrease in realized gains of $1.4 million.

The increase in cost of natural gas marketing in the first quarter of 2010 compared to the same period in 2009 is primarily due to an increase in unrealized losses. In the first quarter of 2010, prices on purchases remained relatively flat compared to the same period in 2009. The unrealized losses on cost related contracts increased by $2.2 million.

Natural Gas Marketing Derivative Instruments. 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.

The following table presents our derivative positions in effect as of March 31, 2010, related to natural gas marketing.

	Collars			Fixed-Price Swaps		NYMEX Basis Protection Swaps		
Commodity/ Derivative Instrument	Quantity (Gas-Mmbtu)	Weighted Average Contract Price Floors	Weighted Average Contract Price Ceilings	Quantity (Gas-Mmbtu)	Weighted Average Contract Price	Quantity (Gas-Mmbtu)	Weighted Average Contract Price	Fair Value At March 31, 2010 (1) (in thousands)
Natural Gas Physical Sales								
04/01 - 06/30/2010	-	$-	$-	58,154	$6.04	19,565	$0.70	$ 117
07/01 - 09/30/2010	-	-	-	42,415	6.80	12,503	0.59	102
10/01 - 12/31/2010	-	-	-	29,573	6.77	31,880	0.70	67
01/01 - 03/31/2011	-	-	-	-	-	35,043	0.70	20
04/01 - 12/31/2011	-	-	-	-	-	13,635	0.86	10
01/01 - 04/30/2012	-	-	-	-	-	3,150	1.40	3
Financial Purchases								
04/01 - 06/30/2010	-	-	-	57,659	5.10	-	-	(68)
07/01 - 09/30/2010	-	-	-	41,938	5.44	-	-	(52)
10/01 - 12/31/2010	-	-	-	29,374	5.41	-	-	(20)
Financial Sales								
04/01 - 06/30/2010	52,500	4.53	7.16	689,100	6.56	-	-	1,867

07/01 - 09/30/2010	52,500	4.53	7.16	689,100	6.56	-	-	1,684
10/01 - 12/31/2010	52,500	4.53	7.16	603,100	6.63	-	-	1,166
01/01 - 03/31/2011	52,500	4.53	7.16	454,200	6.42	-	-	480
04/01 - 12/31/2011	-	-	-	444,000	6.38	-	-	476
Physical Purchases								
04/01 - 06/30/2010	52,500	4.53	7.14	689,550	6.52	-	-	(1,679)
07/01 - 09/30/2010	52,500	4.53	7.14	689,550	6.52	-	-	(1,533)
10/01 - 12/31/2010	52,500	4.53	7.14	603,250	6.60	-	-	(1,031)
01/01 - 03/31/2011	52,500	4.53	7.14	454,200	6.37	-	-	(374)
04/01 - 12/31/2011	-	-	-	444,000	6.39	-	-	(431)
Total Natural Gas	420,000			6,019,163		115,776		$ 804

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(1) Approximately 7% of the fair value of our derivative assets and 97% of our derivative liabilities were measured using significant unobservable inputs (Level 3), see Note 3, Fair Value Measurements, to the accompanying financial statements.

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Other Costs and Expenses

Exploration Expense and Impairment of Natural Gas and Oil Properties

The following table presents the major components of exploration expense and impairment of natural gas and oil properties.

	Three Months Ended March 31,	
	2010	2009
	(in thousands)	
Impairment/amortization of unproved properties	$ 600	$ 614
Exploratory dry hole costs	2,902	832
Geological and geophysical costs	1,047	253
Operating, personnel and other	1,869	3,944
Total exploration expense and impairment of natural gas and oil properties	$ 6,418	$ 5,643

Exploratory dry hole costs for the first quarter of 2010 included the fracturing and testing of several exploratory zones on a well drilled in a prior year located in the Piceance Basin. Additional fracturing and testing of several different exploratory zones for this well is planned for the third quarter of 2010. The $0.8 million increase in geological and geophysical costs for the first quarter of 2010 compared to the same prior year period was primarily related to seismic work in the Marcellus Shale. Operating, personnel and other decreased $2.1 million for the first quarter of 2010 compared to the same prior year period primarily due to the demobilization of drilling rigs in the Piceance Basin of $0.9 million and an inventory impairment of $0.7 million in 2009.

General and Administrative Expense.

General and administrative expense decreased from $12.1 million in the first quarter of 2009 to $10.7 million in the same period of 2010, a decrease of $1.4 million. The decrease is primarily related to the expensing of previously capitalized 2008 acquisition costs of $1.5 million in the first quarter of 2009 pursuant to the adoption of a new accounting standard.

Depreciation, Depletion, and Amortization.

Natural gas and oil properties. DD&A expense related to natural gas and oil properties is directly related to production volumes for the period. The weighted average DD&A rate for the first quarter of 2010 was relatively unchanged at $2.91 per Mcfe compared to $2.90 per Mcfe for the same period in 2009.

The following table presents our DD&A rate for natural gas and oil properties by area.

Three Months Ended March 31,	
2010	2009
(per Mcfe)	

Rocky Mountain Region:		
Wattenberg Field (1)	$ 3.66	$ 4.08
Piceance Basin	2.45	2.36
NECO	2.01	1.81
Appalachian Basin	2.64	1.86
Michigan Basin	1.89	1.49

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(1) Although the Wattenberg Field development costs and DD&A rates are higher than the other fields, the relative value of its oil production currently more than offsets this cost difference.

Non-natural gas and oil properties. Depreciation expense for non natural gas and oil properties was $1.9 million for the first quarter of 2010, relatively unchanged from the same prior year quarter.

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Interest Expense

The decrease in interest expense for the first quarter of 2010 compared to the same period in 2009 was primarily due to lower outstanding balances on our credit facility, resulting in a savings of $1.4 million, offset in part by a $0.5 million increase in amortization of debt issuance costs related to our May 2009 amendment to our credit facility. Interest costs capitalized for the first quarter of 2009 were $0.6 million and immaterial for the first quarter of 2010.

Provision/Benefit for Income Taxes

The effective income tax rate for continuing operations ("rate") for the first quarter of 2010 was 37.5% (provision on income) compared to 41.3% (benefit on a loss) in the same period of 2009. The 2010 rate reflects a tax benefit from our statutory percentage depletion deduction. The first quarter of 2010 and 2009 rates, excluding the effect of discrete items, were 37.5% and 42.1%, respectively.

Beginning with our 2010 tax year, we have been accepted into and have agreed to participate in the IRS Compliance Assurance Process Program. As part of our entrance into this program, we have agreed to an accelerated timeline for the IRS examination of our 2007, 2008 and 2009 tax years. This examination is scheduled to begin in May 2010.

Discontinued Operations

Since 2007, we have not had significant revenue from our well drilling activities, and in January 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. As of June 30, 2009, we had concluded all partnership drilling and completion activities. We do not have any plans in the foreseeable future to sponsor a drilling partnership and have treated our natural gas and oil well drilling activities as discontinued operations for all periods presented. Prior period financial statements have been restated to present the activities of our natural gas and oil well drilling operations as discontinued operations.

Net Income (Loss) Attributable to Shareholders/Adjusted Net Income Attributable to Shareholders

Net income attributable to shareholders for the first quarter of 2010 was $23.7 million compared to a net loss of $5.7 million for the same period in 2009. Adjusted net income attributable to shareholders, a non-GAAP financial measure, for the first quarter of 2010 was $10.9 million compared to $4.1 million for the same period in 2009. The quarter-over-quarter changes in net income attributable to shareholders are discussed above. These same factors similarly impacted adjusted net income attributable to shareholders, with the exception of the unrealized derivative gains and losses on derivatives and provision for underpayment of gas sales, adjusted for taxes. See Reconciliation of Non-GAAP Financial Measures, below, for a more detailed discussion of this non-GAAP financial measure.

Financial Condition

Capital Resources and Liquidity

Our primary sources of cash for the first quarter of 2010 were from funds generated from the sale of natural gas and oil production and the realized gains from our derivative positions. These sources of cash were primarily used to fund our operating costs, general and administrative activities and our capital expenditures, including both our developmental and exploratory activities. Additionally, we were able to improve our liquidity position by reducing borrowings outstanding under the credit facility. Our primary sources of cash from operations are sales of natural gas and oil. Fluctuations in our operating cash flow are substantially driven by changes in commodity prices and production volumes. Commodity prices have historically been volatile and we manage this volatility through our derivative program. Therefore, one of the primary sources of our cash flow from operations becomes the net activity between our natural gas and oil sales and realized derivative gains and losses. However, we do not hold economic hedges for more than 80% of our expected future production from producing wells, nor do we engage in speculative positions. Consequently, we may still have significant fluctuations in our cash flows from operations, which may result in an increase or decrease in our expected developmental and exploratory activities in the future. As of March 31, 2010, we had natural gas and oil derivative positions in place covering 68.7% of our expected natural gas production and 55.1% of our expected oil production for the remainder of 2010, at an average price of $4.99 per Mcf and $91.32 per Bbl, respectively. See Results of Operations for further discussion of the impact of prices and volumes on sales from operations and the impact of derivative activities on our revenues.

From time to time, our working capital will reflect a surplus, while at other times it will reflect a deficit. The primary factors affecting our working capital are our current unrealized derivative position, the timing of our payments to reduce our borrowings on our credit facility and the other variables discussed above. Our working capital was reduced by $10.4 million from $32.9 million at December 31, 2009, to $22.5 million at March 31, 2010. The majority of this decrease is due to our increase in accounts payable of $6 million as a result of our increased drilling program late in the quarter and changes in our current deferred taxes of $4 million.

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We ended March 2010 with cash and cash equivalents of $26.5 million and availability under our credit facility of $227.3 million for a total liquidity position of $253.8 million compared to $238.2 million at December 31, 2009. Our operating cash flows of $51.3 million for the first quarter of 2010 provided us with ample capital to reduce our borrowings under our credit facility by $21 million, net of borrowings, and consequently contribute to the $15.6 million or 6.5% increase in our liquidity position. With our current liquidity position, including our working capital surplus and expected cash flow from operations, we believe that we have sufficient working capital for operations and our planned uses of capital through 2011.

Cash flows from operations are impacted by commodity prices, production volumes, realized gains and losses from our derivative positions, operating costs and general and administrative expenses. Cash provided by operating activities was $51.3 million for the first quarter of 2010 compared to $35.9 million for the same quarter in 2009. The $15.5 million increase in the first quarter of 2010 was primarily due to the increase in natural gas and oil sales of $20.6 million, the decrease in natural gas and oil production and well operations cost of $0.7 million and the decrease in general and administrative expense of $1.4 million offset by a decrease in realized derivative gains of $15 million. The remaining change in our operating cash flow was primarily due to changes in our assets and liabilities related to the timing of cash payments and receipts. The key components for the changes in our cash flows from operations are described in more detail in our Results of Operations above.

Adjusted cash flows from operations were $49.3 million for the first quarter of 2010 compared to $39.7 million for the same period in 2009. Adjusted EBITDA was $53.7 million for the first quarter of 2010 compared to $46.2 million for the same period in 2009. These increases were primarily due to the same factors mentioned above for changes in cash provided by operating activities without regard to timing of cash payments and receipts of our assets and liabilities. See Reconciliation of Non-GAAP Financial Measures, below, for a more detailed discussion of these non-GAAP financial measures.

Cash flows used for investing activities, primarily drilling capital expenditures, decreased $38 million, or 51.6%, from $73.6 million in the first quarter of 2009 to $35.6 million for the first quarter of 2010. The first quarter 2010 decrease was due primarily to the carryover to the first quarter of 2009 of approximately $42 million of accounts payable related to our 2008 drilling program. The capital spent in the first quarter of 2009 unrelated to 2008 carryover capital was approximately $32 million, which was comparable to the capital spent in the first quarter of 2010. We reduced our drilling activity and capital spending for the balance of 2009 to improve our liquidity position and balance sheet strength. We’ve projected our 2010 developmental capital program to be $127 million versus $79 million for 2009. We currently have one rig operating in the Piceance Basin and two rigs operating in the oil and liquids-rich sections of the Wattenberg Field.

We had a $27.9 million source of cash from financing activities for the first quarter of 2009 and a $21.2 million use of cash for the same period in 2010. The majority of the change was due to the shift from net borrowings of $28 million in the 2009 period to a net payment on borrowings of $21 million in the 2010 period.

Our planned 2010 capital expenditures of $149.9 million, excluding joint venture related projects and acquistions, represent an approximate 37% increase from our 2009 capital expenditures. We believe, based on the current commodity price environment, our cash flows from operations will fund the majority of our 2010 capital spending program. In order to grow our production, we would need to commit greater amounts of capital in 2011 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 natural gas and oil produced from our existing properties declines rapidly in the first few years of production, we cannot maintain our current level of natural gas and oil production and cash flows from operations if capital markets and commodity prices return to their 2009 depressed state for a prolonged period of time, which could have a material negative impact on our operations in the future.

We considered the possibility of reduced available liquidity in planning our 2010 drilling program and believe we will have adequate cash flows from operations during the year to execute our planned capital expenditures. Currently, we operate approximately 94% of our properties, allowing us to direct 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 2010 and beyond if market conditions worsen.

We have experienced no impediments in our ability to access borrowings under our current bank credit facility or the capital markets, as demonstrated by our August 2009 sale of equity. We continue to monitor market events and circumstances and their potential impacts on each of the 13 lenders that comprise our bank credit facility. Our $305 million bank credit facility's borrowing base is subject to size redeterminations each May and November 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. On May 5, 2010, based on our December 31, 2009, reserves, our borrowing base was reaffirmed at $305 million. While we will continue to add producing reserves through our drilling operations, we believe a significant decrease in commodity prices could have a negative impact on our future borrowing base redeterminations.

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We are subject to quarterly financial debt covenants on our bank credit facility. The indenture governing our senior notes contains customary representations and warranties as well as typical restrictive and incurrence covenants. Our debt covenants are described in Note 8, Long-Term Debt, to Consolidated Financial Statements in our 2009 Form 10-K and updated, as necessary, in this Form 10-Q. We were in compliance with all debt covenants as of March 31, 2010. We believe we have sufficient liquidity and capital resources to remain compliant with our debt covenants throughout the next year based upon our 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 or commodity 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 have a shelf registration statement on Form S-3 filed with the SEC on November 26, 2008, declared effective on January 30, 2009. 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 efforts 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. We have available $448.2 million of our shelf from which we may utilize to raise capital.

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

Contractual Obligations and Contingent Commitments

The table below sets forth our contractual obligations and contingent commitments as of March 31, 2010.

		Payments due by period			
Contractual Obligations and Contingent Commitments	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(in thousands)		
Long-term liabilities reflected on the balance sheet (1)					
Long-term debt (2)	$ 262,000	$ -	$ 59,000	$ -	$ 203,000
Asset retirement obligations	25,302	250	418	837	23,797
Derivative contracts (3)	69,804	20,677	39,150	9,977	-
Derivative contracts - affiliated partnerships (4)	16,074	1,812	11,099	3,163	-
Production tax liability	42,233	24,165	18,068	-	-
Other liabilities (5)	10,032	352	3,595	770	5,315
	425,445	47,256	131,330	14,747	232,112
Commitments, contingencies and other arrangements (6)					
Interest on long-term debt (7)	202,180	27,764	52,616	48,720	73,080
Operating leases	6,117	1,757	2,208	1,724	428
Drilling commitment	1,213	-	-	-	1,213
	175,318	18,321	39,490	40,628	76,879

Firm transportation and processing agreements (8)									
Other		625		125		250		250	-
		385,453		47,967		94,564		91,322	151,600
Total	$	810,898	$	95,223	$	225,894	$	106,069	$ 383,712

(1) Table does not include deferred income tax liability to taxing authorities of $185.8 million, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

(2) Amount presented does not agree with the balance sheet in that it does not includes $2.3 million in unamortized notes discount.

(3) 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 $22.9 million.

(4) Represents our affiliated partnerships' designated portion of the fair value of our gross derivative assets.

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

(6) Table does not include maximum annual repurchase obligations to investing partners of $9.2 million, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

(7) 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 $194.9 million payable to the holders of our 12% senior notes and $7.3 million related to our outstanding balance of $59 million on our credit facility, including interest of $0.5 million related to our letter of credit, based on an imputed interest rate of 5.8%.

(8) 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. See Note 9, Commitments and Contingencies – Firm Transportation Agreements, to our accompanying financial statements.

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As managing general partner of 33 partnerships, we have liability for 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 9, Commitments and Contingencies – Litigation, to our accompanying 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. 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.

	Development Wells Three Months Ended March 31,			
	2010		2009	
	Gross	Net	Gross	Net
Productive				
Rocky Mountain Region	43	37.9	22	20.4
Appalachian Basin	-	-	1	1.0
Total productive	43	37.9	23	21.4
Dry				
Rocky Mountain Region	-	-	1	0.5
Total dry	-	-	1	0.5
Total development	43	37.9	24	21.9

	Exploratory Wells Three Months Ended March 31,			
	2010		2009	
	Gross	Net	Gross	Net
Pending determination				
Rocky Mountain Region	-	-	2	2.0
Appalachian Basin	1	0.7	2	1.0
Total exploratory	1	0.7	4	3.0

	Total Wells Three Months Ended March 31,			
	2010		2009	
	Gross	Net	Gross	Net
Total drilling activity	44	38.6	28	24.9
Recompletions/refractures	11	10.5	-	-

As of March 31, 2010, a total of 26 productive wells, 25 drilled in 2010 and one drilled in 2009, were waiting to be fractured and/or for gas pipeline connection.

Commitments and Contingencies

See Note 9, Commitments and Contingencies, to the accompanying financial statements.

Recent Accounting Standards

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

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Critical Accounting Polices and Estimates

The preparation of the accompanying financial statements in conformity with U.S. GAAP 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.

With the exception of the following, there have been no other significant changes to our critical accounting policies and estimates 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 2009 Form 10-K, such policies include revenue recognition, derivatives instruments, natural gas and oil properties, deferred income tax asset valuation and purchase accounting.

Consolidation and Accounting for Variable Interest Entities

Under applicable accounting guidance, a variable interest entity ("VIE") is consolidated by the entity's primary beneficiary. The primary beneficiary of a VIE has both the following characteristics: (1) the power to direct the activities of the VIE that most significantly impact the entity's economic performance and (2) the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

In determining whether we are the primary beneficiary of the VIE, we consider a number of factors, including our ability to direct the activities that most significantly affect the entity's economic success and our contractual rights and responsibilities under the arrangement. These considerations impact the way we account for our existing joint venture relationship. Further, as certain events occur, we reconsider whether those events have caused us to become the primary beneficiary. The consolidation status of our VIE may change as a result of a change in the composition of the board of managers or we enter into new or modified contractual arrangements. A reconsideration event may also occur when we acquire new or additional interests in a VIE.

Reconciliation of Non-GAAP Financial Measures

Adjusted cash flow from operations. We define adjusted cash flow from operations as the cash flow earned or incurred from operating activities without regard to the collection or payment of associated receivables or payables. We believe it is important to consider adjusted cash flow from operations as well as cash flow from operations, as we believe it often provides more transparency into what drives the changes in our operating trends, such as production, prices, operating costs, and related operational factors, without regard to whether the earned or incurred item was collected or paid during the period. We also use this measure because the collection of our receivables or payment of our obligations has not been a significant issue for our business, but merely a timing issue from one period to the next, with fluctuations generally caused by significant changes in commodity prices.

Adjusted net income attributable to shareholders. We define adjusted net income attributable to shareholders as net income (loss) attributable to shareholders plus unrealized derivative losses and provisions for underpayment of gas sales minus unrealized derivative gains, each adjusted for tax effect. We believe it is important to consider adjusted net income attributable to shareholders as well as net income (loss) attributable to shareholders. We believe it often provides more transparency into our operating trends, such as production, prices, operating costs, realized gains and losses from derivatives and related factors, without regard to changes in our net income (loss) attributable to shareholders from our mark-to-market adjustments resulting from unrealized gains and losses from derivatives. Additionally, other items, such as the provision for underpayment of gas sales, which are not indicative of future results, may be excluded to clearly identify operational trends.

Adjusted EBITDA. We define adjusted EBITDA as net income (loss) attributable to shareholders plus unrealized derivative losses, interest expense, net of interest income, income taxes, and depreciation, depletion and amortization for the period minus unrealized derivative gains. We believe adjusted EBITDA is relevant because it is a measure of cash available to fund our capital expenditures and service our debt and is a widely used industry metric which allows comparability of our results with our peers.

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The following table presents a reconciliation of each of our non-GAAP financial measures to its nearest GAAP measure.

	Three Months Ended March 31, 2010	2009
	(in thousands)	
Adjusted cash flow from operations:		
Net cash provided by operating activities	$ 51,345	$ 35,879
Changes in assets and liabilities	(2,016)	3,862
Adjusted cash flow from operations	$ 49,329	$ 39,741
Adjusted net income attributable to shareholders:		
Net income (loss) attributable to shareholders	$ 23,724	$ (5,703)
Unrealized loss (gain) on derivatives, net	(20,490)	13,188
Provision for underpayment of gas sales	-	2,581
Tax effect of above adjustments	7,689	(6,012)
Adjusted net income attributable to shareholders	$ 10,923	$ 4,054
Adjusted EBITDA:		
Net income (loss) attributable to shareholders	$ 23,724	$ (5,703)
Unrealized loss (gain) on derivatives, net	(20,490)	13,188
Interest expense, net	7,795	8,363
Income tax expense (benefit)	14,251	(4,015)
Depreciation, depletion and amortization	28,389	34,360
Adjusted EBITDA	$ 53,669	$ 46,193

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, designated cash (current and non-current) 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. As of March 31, 2010, we held interest-bearing deposits totaling $32.8 million earning an average interest rate of 0.8% per annum.

Based on a sensitivity analysis of the credit facility borrowings as of March 31, 2010, it was estimated that if market interest rates were to increase (decrease) by 1%, our 2010 interest expense would increase (decrease) by $0.6 million.

Commodity Price Risk

See Note 4, Derivative Financial Instruments, to the accompanying financial statements included in this report for additional disclosure regarding our derivative financial instruments including, but not limited to, a summary of our open derivative positions as of March 31, 2010.

We are exposed to the effect of market fluctuations in the prices of natural gas and oil. Price risk represents the potential risk of loss from adverse changes in the market price of natural gas and oil 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 natural gas and oil 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 natural gas and oil. To mitigate a portion of our exposure to adverse market changes, we have entered into various derivative contracts.

- For our natural gas and oil 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.

As of March 31, 2010, our derivative instruments were comprised of commodity collars and swaps, basis protection swaps and physical sales and purchases. We believe our derivative instruments continue to be effective in achieving the risk management objectives for which they were intended.

The following table presents monthly average NYMEX and CIG closing prices for natural gas and oil for the three months ended March 31, 2010, and the year ended December 31, 2009, as well as average sales prices we realized for the respective commodities.

	Three Months Ended March 31, 2010	Year Ended December 31, 2009
Average Index Closing Price		
Natural Gas (per MMBtu)		
CIG	$ 5.14	$ 3.07
NYMEX	5.30	3.99
Oil (per Barrel)		
NYMEX	76.75	58.36
Average Sales Price		
Natural Gas	5.30	3.12
Oil	73.55	55.03

Based on a sensitivity analysis as of March 31, 2010, it was estimated that a 10% increase in natural gas and oil prices, inclusive of basis, over the entire period for which we have derivatives then in place would result in a decrease in fair value of $43.9 million; whereas, a 10% decrease in prices would result in an increase in fair value of $44.1 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 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, the impact of the nonperformance of our counterparties on the fair value of our derivative instruments was not significant.

Disruptions in the credit market may have 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 of a financial institution.

Disclosure of Limitations

Because the information above included only those exposures that exist at March 31, 2010, 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 March 31, 2010, 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 March 31, 2010.

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 Securities Exchange Act of 1934) during the quarter ended March 31, 2010, 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 9, Commitments and Contingencies, to our accompanying 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 2009 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 2009 Form 10-K, except for the following:

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Various proposed Federal legislation initiatives may decrease our ability, and increase the cost, to enter into hedge transactions.

Various measures are being proposed by Congress that would further regulate hedging transactions. This legislation could make it more difficult and costly for independent producers like us to enter into hedging transactions by requiring that we post collateral to a central clearing exchange. Because we currently enter into hedges with financial institutions that are lenders under our credit facility, we are not required to post collateral for those transactions. If we are required to post collateral as a result of new legislation, we would have to do so by utilizing cash or letters of credit, which would reduce our liquidity position and increase costs. Decreasing our ability to enter into hedging transactions would expose us to additional risks related to commodity price volatility and impair our ability to have certainty with respect to a portion of our cash flow, which could lead to decreases in capital spending if commodity prices decrease and could have an adverse impact on future production and reserves.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers.

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
January 1 - 31, 2010	2,240	$ 18.54	-	-
February 1 - 28, 2010	1,162	23.34	-	-
March 1 - 31, 2010	7,560	22.84	-	-
	10,962	22.01		

(1) Purchases during the quarter represent shares purchased pursuant to our stock-based compensation plans for payment of tax liabilities related to the vesting of securities.

Item 3. Defaults Upon Senior Securities - None

Item 4. [Removed and Reserved]

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*	Non-Employee Director Deferred Compensation Plan.	S-8	333-118222	99.1	8/13/2004	
10.2*	2004 Long-Term Equity Compensation Plan amended and restated as of March 8, 2008.	10-K	000-07246	10.26	2/27/2009	
10.3*	Employment Agreement with Richard W. McCullough, Chief Executive Officer, dated as of December 31, 2008, superseded by Exhibit 10.10 below.	10-K	000-07246	10.9	2/27/2009	
10.4*	Employment Agreement with Gysle R. Shellum, Chief Financial Officer, dated as of December 31, 2008, superseded by Exhibit 10.11 below.	10-K	000-07246	10.11	2/27/2009	
10.5*	Employment Agreement with Daniel W. Amidon, General Counsel and Corporate Secretary, dated as of December 31, 2008, superseded by Exhibit 10.12 below.	10-K	000-07246	10.13	2/27/2009	
10.6*	Employment Agreement with Barton R. Brookman, Jr., Senior Vice President of Exploration and Production, dated as of December 31, 2008, superseded by Exhibit 10.14 below.	10-K	000-07246	10.12	2/27/2009	
10.7*	2010 Short-Term Incentive Compensation Performance Metrics for Executive Officers.	8-K	000-07246		3/18/2010	
10.8*	Non-Employee Director Compensation for the 2010-2011 Term.	8-K	000-07246		4/23/2010	
10.9*		8-K	000-07246		4/23/2010	

	Executive Compensation and Short-Term Incentive Targets for 2010.					
10.10*	Employment Agreement with Richard W. McCullough, Chief Executive Officer, dated as of April 19, 2010.	8-K	000-07246	10.1	4/23/2010	
10.11*	Employment Agreement with Gysle R. Shellum, Chief Financial Officer, dated as of April 19, 2010.	8-K	000-07246	10.2	4/23/2010	
10.12*	Employment Agreement with Daniel W. Amidon, General Counsel and Corporate Secretary, dated as of April 19, 2010.	8-K	000-07246	10.3	4/23/2010	
10.13*	Employment Agreement with Lance A. Lauck, Senior Vice President of Business Development, dated as of April 19, 2010.	8-K	000-07246	10.4	4/23/2010	
10.14*	Employment Agreement with Barton R. Brookman, Jr., Senior Vice President of Exploration and Production, dated as of April 19, 2010.	8-K	000-07246	10.5	4/23/2010	
12.1	Computation of Ratio of Earnings to Fixed Charges.					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: May 10, 2010

/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