PETROLEUM DEVELOPMENT CORP
Form 10-Q
May 10, 2011

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, 2011

or

£ TRANSITION REPORT PURSUANT TO SECTION 13 OR 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)
(Doing Business as PDC Energy)

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes T No £

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

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

Large accelerated filer £	Accelerated filer x
Non-accelerated filer £ (Do not check if a smaller reporting company)	Smaller reporting company o

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 23,496,892 shares of the Company's Common Stock ($0.01 par value) were outstanding as of April 22, 2011.

PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This periodic report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act") and Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") regarding our business, financial condition, results of operations and prospects. All statements other than statements of historical facts included in and incorporated by reference into this report are "forward-looking statements" within the meaning of the safe harbor provisions of the United States Private Securities Litigation Reform Act of 1995. 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, NGL and crude oil production and reserves, drilling plans, future cash flows, anticipated liquidity, anticipated capital expenditures, including our ability to fund our 2011 capital plan, our compliance with our debt covenants and the indenture restrictions governing our senior notes, sufficient liquidity to meet our partnership repurchase obligation, the adequacy of our casualty insurance coverage, the impact of decreased commodity prices on future borrowing base redeterminations, the effectiveness of our derivative policies in achieving our risk management objectives, the decrease during the next twelve months of our liability for uncertain tax benefits, funding sources for our acquisitions, the acceleration of our capital spending program due to a rise in crude oil prices, the potential operational benefits and cost synergies due to the acquisition of certain partnerships 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 known and unknown risks and uncertainties incidental to the exploration for, and the acquisition, development, production and marketing of natural gas, NGLs and crude 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 and worldwide demand;
- volatility of commodity prices for natural gas and crude oil;
- changes in estimates of proved reserves;
- inaccuracy of reserve estimates and expected production rates;
- declines in the values of our natural gas and crude oil properties resulting in impairments;
- the future cash flow, liquidity and financial position of the Company;
- the timing and extent of our success in discovering, acquiring, developing and producing reserves;
- our ability to acquire leases, drilling rigs, supplies and services at reasonable prices;
- reductions in the borrowing base under our credit facility;
- risks incidental to the drilling and operation of natural gas and crude oil wells;
- 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 U.S. as well as other oil producing countries throughout the world;
- changes in environmental laws, the regulation and enforcement of those laws and the costs to comply with those laws;
- the impact of environmental events, governmental responses to the events and our ability to insure adequately against such events;
- competition in the oil and gas industry;
- the success of the Company in marketing oil and gas;
- the effect of natural gas and crude oil derivatives activities;
- the availability and cost of capital to us;
- our ability to consummate the prospective mergers of the 2005 partnerships and the timing of consummating these mergers, if at all;
- losses possible from pending or future litigation; and
- the success of strategic plans, expectations and objectives for future operations of the Company.

Further, we urge you to carefully review and consider the cautionary statements and disclosures, specifically those under the heading "Risk Factors," made in this report, our annual report on Form 10-K for the year ended December 31, 2010, filed with the Securities and Exchange Commission ("SEC") on February 24, 2011, as amended April 21, 2011 ("2010 Form 10-K"), and our other filings with the SEC for further information on risks and uncertainties that could affect the Company's business, financial condition and results of operations, which are incorporated by this reference as though fully set forth herein. 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. All forward looking statements are qualified in their entirety by this cautionary statement.

REFERENCES

Unless the context otherwise requires, references to "PDC," "PDC Energy," "the Company," "we," "us," "our," "ours" or "ourselves" in this report refer to the registrant, Petroleum Development Corporation and its consolidated entities. See Note 1, Nature of Operations and Basis of Presentation, to our condensed consolidated financial statements included in this report for a description of our consolidated entities.

References to "the three months ended 2011" refer to the three months ended March 31, 2011, as applicable. References to "the three months ended 2010" refer to the three months ended March 31, 2010, as applicable.

PART I - FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
Condensed Consolidated Balance Sheets
(unaudited; in thousands, except share and per share data)

	March 31, 2011	December 31, 2010 (1)
Assets		
Current assets:		
Cash and cash equivalents	$14,699	$54,372
Accounts receivable, net	62,512	53,978
Accounts receivable affiliates	14,989	11,448
Fair value of derivatives	40,190	42,953
Prepaid expenses and other current assets	20,415	14,072
Total current assets	152,805	176,823
Properties and equipment, net	1,152,957	1,120,038
Assets held for sale	—	5,191
Fair value of derivatives	37,234	44,464
Accounts receivable affiliates	7,518	8,478
Other assets	37,833	34,041
Total Assets	$1,388,347	$1,389,035
Liabilities and Equity		
Liabilities		
Current liabilities:		
Accounts payable	$52,262	$47,271
Accounts payable affiliates	9,507	9,605
Production tax liability	16,099	16,226
Fair value of derivatives	42,266	29,998
Funds held for distribution	31,395	29,755
Accrued interest payable	5,069	10,051
Other accrued expenses	16,406	17,723
Total current liabilities	173,004	160,629
Long-term debt	296,709	295,695
Deferred income taxes	181,407	187,999
Asset retirement obligations	27,937	27,797
Fair value of derivatives	43,937	36,644
Accounts payable affiliates	10,297	12,111
Other liabilities	30,455	25,919
Total liabilities	763,746	746,794
Commitments and contingent liabilities		
Equity		
Shareholders' equity:		
Preferred shares, par value $0.01 per share; authorized 50,000,000 shares; issued: none	—	—
	235	235

Common shares, par value $0.01 per share; authorized 100,000,000 shares; issued: 23,478,611 in 2011 and 23,462,326 in 2010		
Additional paid-in capital	211,482	209,198
Retained earnings	412,919	432,843
Treasury shares, at cost: 2,938 in 2011 and 2010	(111)	(111)
Total shareholders' equity	624,525	642,165
Noncontrolling interest in subsidiary	76	76
Total equity	624,601	642,241
Total Liabilities and Equity	$1,388,347	$1,389,035

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(1) Derived from audited 2010 balance sheet.

See accompanying Notes to Condensed Consolidated Financial Statements
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PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
Condensed Consolidated Statements of Operations
(unaudited; in thousands, except per share data)

	Three Months Ended March 31,			
	2011		2010	
Revenues:				
Natural gas, NGL and crude oil sales	$63,879		$57,827	
Sales from natural gas marketing	15,202		22,687	
Commodity price risk management gain (loss), net	(23,882	)	43,222	
Well operations, pipeline income and other	1,876		2,589	
Total revenues	57,075		126,325	
Costs, expenses and other:				
Production costs	21,039		14,961	
Cost of natural gas marketing	14,993		22,323	
Exploration expense	2,151		6,418	
General and administrative expense	13,873		10,694	
Depreciation, depletion and amortization	32,357		27,458	
Total costs, expenses and other	84,413		81,854	
Income (loss) from operations	(27,338	)	44,471	
Interest income	9		5	
Interest expense	(9,062	)	(7,800	)
Income (loss) from continuing operations before income taxes	(36,391	)	36,676	
Provision (benefit) for income taxes	(13,847	)	13,804	
Income (loss) from continuing operations	(22,544	)	22,872	
Income from discontinued operations, net of tax	2,620		797	
Net income (loss)	(19,924	)	23,669	
Less: net loss attributable to noncontrolling interests	—		(55	)
Net income (loss) attributable to shareholders	$(19,924	)	$23,724	
Amounts attributable to Petroleum Development Corporation shareholders:				
Income (loss) from continuing operations	$(22,544	)	$22,927	
Income from discontinued operations, net of tax	2,620		797	
Net income (loss) attributable to shareholders	$(19,924	)	$23,724	
Earnings (loss) per share attributable to shareholders:				
Basic				
Income (loss) from continuing operations	$(0.96	)	$1.19	
Income from discontinued operations	0.11		0.04	
Net income (loss) attributable to shareholders	$(0.85	)	$1.23	
Diluted				
Income (loss) from continuing operations	$(0.96	)	$1.19	
Income from discontinued operations	0.11		0.04	
Net income (loss) attributable to shareholders	$(0.85	)	$1.23	

Weighted average common shares outstanding:		
Basic	23,428	19,191
Diluted	23,428	19,287

See accompanying Notes to Condensed Consolidated Financial Statements

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

	Three Months Ended March 31,	
	2011	2010
Cash flows from operating activities:		
Net income (loss)	$(19,924)	$23,669
Adjustments to net income (loss) to reconcile to net cash provided by operating activities:		
Unrealized (gain) loss on derivatives, net	27,745	(20,490)
Depreciation, depletion and amortization	32,357	28,389
Amortization and impairment of unproved natural gas and crude oil properties	453	600
Exploratory dry hole costs	35	2,902
Loss (gain) from sale of leaseholds/assets	(3,928)	270
Deferred income taxes	(14,024)	11,632
Other	3,385	2,357
Changes in assets and liabilities	(10,623)	2,016
Net cash provided by operating activities	15,476	51,345
Cash flows from investing activities:		
Capital expenditures	(71,079)	(32,581)
Deconsolidation/change in ownership effect on cash and cash equivalents	(101)	(3,074)
Proceeds from sale of leaseholds/assets	9,952	16
Net cash used in investing activities	(61,228)	(35,639)
Cash flows from financing activities:		
Proceeds from credit facility	—	64,000
Payment of credit facility	—	(85,000)
Contribution by investing partner in PDCM	6,407	—
Other	(328)	(190)
Net cash provided by (used in) financing activities	6,079	(21,190)
Net decrease in cash and cash equivalents	(39,673)	(5,484)
Cash and cash equivalents, beginning of period	54,372	31,944
Cash and cash equivalents, end of period	$14,699	$26,460
Supplemental cash flow information:		
Cash payments (receipts) for:		
Interest, net of capitalized interest	$12,314	$7,067
Income taxes, net of refunds	85	(33)
Non-cash investing activities:		
Change in accounts payable related to purchases of properties and equipment	5,832	6,056
Change in asset retirement obligation, with a corresponding increase to properties and equipment, net of disposals	229	207

See accompanying Notes to Condensed Consolidated Financial Statements

PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
MARCH 31, 2011
(unaudited)

NOTE 1 - NATURE OF OPERATIONS AND BASIS OF PRESENTATION

PDC Energy is a domestic independent natural gas and crude oil company engaged in the exploration for and the acquisition, development, production and marketing of natural gas, natural gas liquids ("NGLs") and crude oil. As of March 31, 2011, we owned an interest in approximately 5,000 wells located primarily in the Rocky Mountain Region and the Permian and Appalachian Basins. We operate through two business segments: (1) natural gas and crude oil sales and (2) natural gas marketing.

The accompanying unaudited condensed consolidated financial statements include the accounts of PDC, our wholly-owned subsidiaries, an entity in which we have a controlling financial interest and our proportionate share of PDC Mountaineer, LLC ("PDCM") and 29 of our affiliated partnerships. Pursuant to the proportionate consolidation method, our accompanying financial statements include our pro rata share of assets, liabilities, revenues and expenses of the entities which we proportionately consolidate. All material intercompany accounts and transactions have been eliminated in consolidation. As of March 31, 2011, PDCM was consolidated at 52.7% and the 29 partnerships were consolidated at varying percentages.

As of December 31, 2010, PDCM was consolidated at 55.8%, representing our ownership interest. On January 1 and March 1, 2011, our joint venture partner made capital contributions of cash to PDCM of $7 million and $5 million, respectively. The contributions resulted in our ownership interest decreasing from 55.8% to 53.9%, then to 52.7%. Each change in our ownership interest resulted in a decrease in our proportionate share of net assets and any future earnings.

With the exception of our initial capital contribution in October 2009, we have not entered into any arrangement that would require us to provide financial support to PDCM. Further, we are not liable for any debts, obligations or liabilities of the joint venture and its creditors have no recourse against our general credit in the event of default. None of our affiliated partnerships’ wells were included in the joint venture.

The following table presents the carrying amount and classification of our proportionate share of PDCM's assets and liabilities included in our balance sheets.

	March 31, 2011	December 31, 2010
	(in thousands)	
Cash and cash equivalents	$1,808	$1,560
Other current assets	2,560	3,206
Property, plant and equipment, net	103,018	101,679
Other assets	1,979	1,986
Total assets	$109,365	$108,431
Total current liabilities	$6,622	$4,641
Asset retirement obligations	8,322	8,681
Other liabilities	1,784	1,370
Equity	92,637	93,739
Total liabilities and equity	$109,365	$108,431

In our opinion, the accompanying financial statements contain all adjustments (consisting of only normal recurring adjustments) necessary for a fair statement 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 2010 Form 10-K. Our accounting policies are described in the Notes to Consolidated Financial Statements in our 2010 Form 10-K and updated, as necessary, in this Form 10-Q. The results of operations for the three months ended 2011, 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.

Certain reclassifications have been made to prior period financial statements to conform to the current year presentation. The reclassifications are directly related to our discontinued operations. The reclassifications had no impact on previously reported cash flows, net income, earnings per share or shareholders' equity. See Note 12 for additional information regarding our discontinued operations.

PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

NOTE 2 - RECENT ACCOUNTING STANDARDS

Recently Adopted 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. These changes were effective for our financial statements issued for the annual reporting period, and for interim reporting periods within the year, beginning after December 15, 2010. The adoption of this change did not have a material impact on our financial statements.

NOTE 3 - FAIR VALUE MEASUREMENTS AND DISCLOSURES

Derivative Financial Instruments

The following table presents, for each hierarchy level, our derivative assets and liabilities, both current and non-current portions, including the derivative assets and liabilities designated to our affiliated partnerships and our proportionate share of PDCM's derivative assets and liabilities, measured at fair value on a recurring basis.

	March 31, 2011			December 31, 2010		
	Quoted Prices in Active Markets (Level 1) (in thousands)	Significant Unobservable Inputs (Level 3)	Total	Quoted Prices in Active Markets (Level 1)	Significant Unobservable Inputs (Level 3)	Total
Assets:						
Commodity based derivatives contracts	$58,740	$ 18,624	$77,364	$64,138	$ 23,168	$87,306
Basis protection derivative contracts	—	60	60	—	111	111
Total assets	58,740	18,684	77,424	64,138	23,279	87,417
Liabilities:						
Commodity based derivatives contracts	644	39,717	40,361	51	20,011	20,062
Basis protection derivative contracts	—	45,842	45,842	—	46,580	46,580
Total liabilities	644	85,559	86,203	51	66,591	66,642
Net asset (liability)	$58,096	$ (66,875)	$(8,779)	$64,087	$ (43,312)	$20,775

PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following table presents a reconciliation of our Level 3 fair value measurements.

	Three Months Ended March 31,	
	2011	2010
	(in thousands)	
Fair value, net liability, beginning of period	$(43,312)	$(28,994)
Changes in fair value included in statement of operations line item:		
Commodity price risk management gain (loss), net	(24,405)	12,431
Sales from natural gas marketing	14	383
Cost of natural gas marketing	(6)	(3,293)
Changes in fair value included in balance sheet line item (1):		
Accounts receivable affiliates	(104)	(2,320)
Accounts payable affiliates	(654)	(4,538)
Settlements included in statement of operations line items:		
Commodity price risk management gain (loss), net	720	(20,980)
Sales from natural gas marketing	(75)	—
Cost of natural gas marketing	947	(5)
Fair value, net liability, end of period	$(66,875)	$(47,316)
Changes in unrealized gains (losses) relating to assets (liabilities) still held as of period end, included in statement of operations line item:		
Commodity price risk management gain (loss), net	$(18,906)	$8,477
Sales from natural gas marketing	(7)	353
Cost of natural gas marketing	(46)	(3,604)
	$(18,959)	$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 for additional disclosure related to our derivative financial instruments.

Non-Derivative Financial 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, as of March 31, 2011, we estimate the fair value of the portion of our long-term debt related to the 3.25% convertible senior notes due 2015 to be $151.9 million or 132.1% of par value and the portion related to our 12% senior notes due 2018 to be $229.9 million or 113.2% of par value. We determined these valuations based upon measurements of broker/dealer quotes and trading activity, respectively.

NOTE 4 - DERIVATIVE FINANCIAL INSTRUMENTS

As of March 31, 2011, we had derivative instruments in place for a portion of our anticipated production through 2015 for a total of 43,533.4 BBtu of natural gas and 2,685.8 MBbls of crude oil.

The following table presents the location and fair value amounts of our derivative instruments on the balance sheets. These derivative instruments were comprised of commodity floors, collars and swaps, basis protection swaps and physical sales and purchases.

PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

Derivatives instruments not designated as hedges (1):		Balance sheet line item	Fair Value March 31, 2011	December 31, 2010
			(in thousands)	
Derivative assets:	Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	$30,500	$32,837
	Related to affiliated partnerships (2)	Fair value of derivatives	8,471	8,231
	Related to natural gas marketing	Fair value of derivatives	1,171	1,811
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	48	74
			40,190	42,953
	Non Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	26,845	32,270
	Related to affiliated partnerships (2)	Fair value of derivatives	10,297	12,111
	Related to natural gas marketing	Fair value of derivatives	80	46
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	12	37
			37,234	44,464
Total derivative assets			$77,424	$87,417
Derivative liabilities:	Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	$20,487	$10,636
	Related to affiliated partnerships (3)	Fair value of derivatives	1,986	1,676
	Related to natural gas marketing	Fair value of derivatives	912	1,492
	Basis protection contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	13,665	11,725
	Related to affiliated partnerships (3)	Fair value of derivatives	5,215	4,462
	Related to natural gas marketing	Fair value of derivatives	1	7
			42,266	29,998
	Non Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	16,943	6,231
	Related to affiliated partnerships (3)	Fair value of derivatives	—	(3)
	Related to natural gas marketing	Fair value of derivatives	33	30
	Basis protection contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	19,442	21,905
	Related to affiliated partnerships (3)	Fair value of derivatives	7,518	8,481
	Related to natural gas marketing	Fair value of derivatives	1	—

	43,937	36,644
Total derivative liabilities	$86,203	$66,642

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(1) As of March 31, 2011, and December 31, 2010, none of our derivative instruments were designated as hedges.
(2) Our balance sheets include a corresponding payable to our affiliated partnerships of $18.8 million and $20.3 million as of March 31, 2011, and December 31, 2010, respectively.
(3) Our balance sheets include a corresponding receivable from our affiliated partnerships of $14.7 million and $14.6 million as of March 31, 2011, and December 31, 2010, respectively.

PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following table presents the impact of our derivative instruments on our statements of operations.

	Three Months Ended March 31,					
	2011			2010		
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 (loss), net						
Realized gains	$3,322	$466	$3,788	$21,067	$1,857	$22,924
Unrealized gains (losses)	(3,322)	(24,348)	(27,670)	(21,067)	41,365	20,298
Total commodity price risk management gain (loss), net (1)	$—	$(23,882)	$(23,882)	$—	$43,222	$43,222
Sales from natural gas marketing						
Realized gains	$1,007	$135	$1,142	$752	$308	$1,060
Unrealized gains (losses)	(1,007)	(10)	(1,017)	(752)	4,264	3,512
Total sales from natural gas marketing (2)	$—	$125	$125	$—	$4,572	$4,572
Cost of natural gas marketing						
Realized losses	$(770)	$(190)	$(960)	$(774)	$(322)	$(1,096)
Unrealized gains (losses)	770	172	942	774	(4,094)	(3,320)
Total cost of natural gas marketing (2)	$—	$(18)	$(18)	$—	$(4,416)	$(4,416)

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

Concentration of Credit Risk. We make extensive use of over-the-counter derivative instruments that enable us to manage a portion of our exposure to price volatility from producing and marketing natural gas and crude 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. We have evaluated the credit risk of our derivative assets from our counterparties 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.

The following table presents the derivative counterparties that expose us to credit risk.

Counterparty Name	Fair Value of Derivative Assets

	As of March 31, 2011 (in thousands)
JPMorgan Chase Bank, N.A. (1)	$35,522
Crèdit Agricole CIB (1)	25,370
Wells Fargo Bank, N.A. (1)	13,667
Various (2)	2,865
Total	$77,424

(1)Major lender in our credit facility, see Note 7.
(2)Represents a total of 19 counterparties, including two lenders in our credit facility.

PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

NOTE 5 - PROPERTIES AND EQUIPMENT

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

	March 31, 2011	December 31, 2010
	(in thousands)	
Properties and equipment, net:		
Natural gas and crude oil properties		
Proved	$1,488,520	$1,429,667
Unproved	69,906	79,053
Total natural gas and crude oil properties	1,558,426	1,508,720
Pipelines and related facilities	34,203	34,262
Transportation and other equipment	32,456	32,410
Land, buildings and leasehold improvements	14,514	13,379
Construction in progress	54,260	42,128
	1,693,859	1,630,899
Accumulated DD&A	(540,902)	(510,861)
Properties and equipment, net	$1,152,957	$1,120,038

NOTE 6 - INCOME TAXES

We evaluate our estimated annual effective income tax rate on a quarterly basis based on current and forecasted operating 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 and may make quarterly comparisons not meaningful. A tax expense or benefit unrelated to the current year 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 income or tax benefit on loss at the most recent estimated annual effective tax rate, adjusted for the effect of discrete items.

The effective tax rate for continuing operations for the three months ended 2011, was 38.1% compared to 37.6% for the three months ended 2010. The tax benefit recognized for the three months ended 2011 has been limited to the amount expected to be realized during the year. The limitation was $1.2 million. The effective tax rate differs from the statutory rate primarily due to net permanent deductions, largely percentage depletion, increasing the tax benefit on loss for this period, while decreasing the tax provision on pretax income for the same prior year period. There were no significant discrete items recorded during each of the three months ended 2011 or 2010.

As of March 31, 2011, we had a gross liability for uncertain tax benefits of $1.2 million, which was substantially unchanged from December 31, 2010. If recognized, $1.1 million of this liability would affect our effective tax rate. This liability is reflected in other accrued expenses on our accompanying balance sheet. In 2010, the Internal Revenue Service ("IRS") commenced its examination of our 2007, 2008 and 2009 tax years. This examination is expected to be completed during the second quarter of 2011. Therefore, we expect the liability for uncertain tax benefits to decrease significantly during the next twelve-month period as items are either resolved without change, converted to amounts due to the IRS or removed due to the expiration of the statute of limitations.

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.

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NOTE 7 - LONG-TERM DEBT

Long-term debt consists of the following:

	March 31, 2011	December 31, 2010
	(in thousands)	
Senior notes		
3.25% Convertible senior notes due 2016:		
Principal amount	$115,000	$115,000
Unamortized discount	(19,310)	(20,252)
3.25% Convertible senior notes due 2016, net of discount	95,690	94,748
12% Senior notes due 2018:		
Principal amount	203,000	203,000
Unamortized discount	(1,981)	(2,053)
12% Senior notes due 2018, net of discount	201,019	200,947
Total senior notes	296,709	295,695
Total long-term debt	$296,709	$295,695

Senior Notes

3.25% Convertible Senior Notes Due 2016. In November 2010, we issued $115 million of 3.25% convertible senior notes due 2016 in a private placement. The maturity for the payment of principal is May 15, 2016. Interest at the rate of 3.25% per year is payable in cash semiannually in arrears on each May 15 and November 15, commencing on May 15, 2011. We allocated the gross proceeds of the convertible notes between the liability and equity components of the debt. The initial $94.3 million liability component was determined based on the fair value of similar debt instruments, excluding the conversion feature, with similar terms and priced on the same day we issued our convertible notes. The original issue discount and the deferred note issuance costs are being amortized to interest expense over the term of the debt using an effective interest rate of 7.4%. We have initially elected a net-settlement method to satisfy our conversion obligation, which allows us to settle the $1,000 principal amount of the convertible notes in cash and to settle the excess conversion value in shares, as well as cash in lieu of fractional shares.

12% Senior Notes Due 2018. In 2008, we issued $203 million of 12% senior notes due 2018 in a private placement. The maturity for the payment of principal is February 15, 2018. Interest at the rate of 12% per year is payable in cash semiannually in arrears on each February 15 and August 15. The senior notes were issued at a discount, 98.572% of the principal amount. The indenture governing the notes contains customary representations and warranties as well as typical restrictive covenants. The original issue discount and the deferred note issuance costs are being amortized to interest expense over the term of the debt using the effective interest method.

We were in compliance with all covenants related to our senior notes as of March 31, 2011, and expect to remain in compliance throughout the next twelve-month period.

Bank Credit Facilities

Subsequent to March 31, 2011, on May 6, 2011, we completed the redetermination of our corporate bank credit facility's borrowing base. Similarly, PDCM completed its redetermination on April 20, 2011. See Note 15 for further discussion.

Corporate Bank Credit Facility. We operate under a credit facility dated as of November 5, 2010, as amended December 22, 2010, with an aggregate revolving commitment or borrowing base of $321.2 million. The maximum allowable facility amount is $600 million. The credit facility is with certain commercial lending institutions and is available for working capital requirements, capital expenditures, acquisitions, general corporate purposes and to support letters of credit.

Our credit facility borrowing base is subject to size redetermination semiannually based on a valuation of our reserves at December 31 and June 30 and is also subject to a redetermination upon the occurrence of certain events. The borrowing base of the credit facility will be the loan value assigned to the proved reserves attributable to our natural gas and crude oil interests, excluding proved reserves attributable to PDCM and our 29 affiliated partnerships. The credit facility is secured by a pledge of the stock of certain of our subsidiaries, mortgages of certain producing natural gas and crude oil properties and substantially all of our other assets. Neither PDCM nor the various limited partnerships that we have sponsored and continue to serve as the managing general partner are guarantors of the credit facility.

Our outstanding principal amount accrues interest at a varying interest rate that fluctuates with an alternate base rate (equal to the greater of JPMorgan Chase Bank, N.A.'s prime rate, the federal funds rate plus a premium and 1-month LIBOR plus a premium), or at our election, a rate equal to the rate for dollar deposits in the London interbank market for certain time periods. Additionally, commitment fees,

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interest margin and other bank fees, charged as a component of interest, vary with our utilization of the facility. No principal payments are required until the credit agreement expires on November 5, 2015, or in the event that the borrowing base would fall below the outstanding balance. The credit facility contains covenants customary for agreements of this type.

We have outstanding an undrawn $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 0.125% per annum and an additional quarterly maintenance fee equivalent to the spread over Eurodollar loans (2.0% per annum as of March 31, 2011) for the period the letter of credit remains outstanding. The letter of credit expires on May 22, 2012.

As of March 31, 2011, and December 31, 2010, we had no outstanding draws on our credit facility. We pay a fee of 0.5% per annum on the unutilized commitment on the available funds under our credit facility. As of March 31, 2011, the available funds under our credit facility were $302.5 million. The weighted average borrowing rate on our credit facility, including the letter of credit, was 0.6% per annum for the three months ended 2011 and 1.1% per annum for the three months ended 2010.

PDCM Credit Facility. PDCM has a credit facility dated as of April 30, 2010, with an initial borrowing base of $10 million. The credit facility is subject to and secured by PDCM's properties, including our proportionate share of such properties. The credit facility borrowing base is subject to size redetermination semiannually based upon a valuation of PDCM's reserves at December 31 and June 30; further, either PDCM or the lenders may request a redetermination upon the occurrence of certain events. Pursuant to the interests of the joint venture, the credit facility will be utilized by PDCM for the exploration and development of its Appalachian assets. As of March 31, 2011, there were no amounts outstanding related to this credit facility.

As of March 31, 2011, both the Company and PDCM were in compliance with all bank credit facility covenants and expect to remain in compliance throughout the next twelve-month period.

NOTE 8 - ASSET RETIREMENT OBLIGATIONS

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

	Amount (in thousands)
Balance at December 31, 2010 (1)	$28,047
Change in ownership interest of PDCM	(485)
Obligations incurred with development activites and assumed with acquisitions	450
Accretion expense	396
Obligations discharged with disposal of properties and asset retirements	(221)
Balance at March 31, 2011	28,187
Less current portion	(250)
Long-term portion	$27,937

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(1) Includes $0.2 million as of December 31, 2010, related to assets held for sale.

NOTE 9 - COMMITMENTS AND CONTINGENCIES

Merger Agreements. In November 2010, pursuant to our previously announced partnership acquisition plan, we entered into separate merger agreements with three of our affiliated partnerships: PDC 2005-A Limited Partnership, PDC 2005-B Limited Partnership and the Rockies Region Private Limited Partnership (collectively, the "2005 Partnerships"). We serve as the managing general partner of each of the 2005 Partnerships. Definitive proxy statements for each of the 2005 Partnerships requesting approval for the applicable merger were mailed to the non-affiliated investor partners of the 2005 Partnerships on February 7, 2011. Pursuant to each merger agreement, if the merger is approved by the holders of a majority of the limited partnership units held by limited partners of that partnership not owned by us (the "non-affiliated investor partners"), as well as the satisfaction of other customary closing conditions, then such partnership will merge with and into a wholly-owned subsidiary of ours. In light of the recent rise in commodity prices, in late February 2011, we reevaluated the initial aggregate merger consideration of $36.4 million agreed to in the merger agreements for the 2005 Partnerships and proposed to offer supplemental merger consideration of $6.9 million to the non-affiliated investor partners of the 2005 Partnerships. In early May 2011, we mailed the proxy supplements to the non-affiliated investor partners of the 2005 Partnerships. The special meetings whereby non-affiliated investor partners of the 2005 Partnerships will have an opportunity to vote and approve the applicable merger agreements are currently scheduled for June 15, 2011. If the required approvals are received from the non-affiliated investor partners at the special meetings and various other closing conditions are satisfied, we expect the aggregate purchase price to acquire the 2005 Partnerships to be $43.3 million. We expect to finance the acquisition of the 2005 Partnerships by borrowing funds under our revolving credit facility.

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Drilling Rig Contract. In order to secure the services of a drilling rig, PDCM entered into a commitment with a drilling contractor for the services of a drilling rig. The commitment expires in October 2012. Included in production costs in the statement of operations for the three months ended 2011, we recognized a charge of $0.5 million related to our proportionate share of rig laydown costs. As of March 31, 2011, our proportionate share of PDCM's related maximum commitment through October 2012 was $5.3 million.

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 working interest owners, PDCM, our affiliated partnerships and other third parties. These contracts require us to pay these transportation and processing charges whether the required volumes are delivered or not. Satisfaction of the volume requirements include volumes produced by us, volumes purchased from third parties and volumes produced by our joint venture and affiliated partnerships. We record in our financial statements only our share of costs based upon our working interest in the wells; however, the costs of all volume shortfalls will be borne by PDC. As of March 31, 2011, we have a liability in the amount of $3.1 million included in other liabilities on the balance sheet related to an agreement in our Piceance Basin. We are currently working with the gas purchaser 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 expected future volumes, we may need to record an additional liability.

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

	For the Twelve Months Ending March 31,						
Area	2012	2013	2014	2015	2016 Through Expiration	Total	Expiration Date
Volume (MMcf)							
Piceance	32,466	32,872	29,399	23,584	65,969	184,290	May 31, 2021
Appalachian Basin (1)	4,587	11,776	15,992	15,992	114,653	163,000	August 31, 2022
NECO	3,200	1,825	1,825	1,825	3,200	11,875	December 31, 2016
Total	40,253	46,473	47,216	41,401	183,822	359,165	
Dollar commitment (in thousands)	$19,801	$22,941	$23,343	$20,290	$86,878	$173,253	

(1) Includes a precedent agreement that becomes effective when a planned pipeline is placed in service, currently expected to be September 2012 and represents 10,629 MMcf of the total MMcf presented for each of the years ending March 31, 2013 and 2014, and 78,915 MMcf thereafter. 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.

Litigation. The Company is involved in various legal proceedings that it considers normal to its business. The Company reviews the status of these proceedings on an ongoing basis and, from time to time, may settle or otherwise resolve these matters on terms and conditions that management believes are in the best interests of the Company. There are no assurances that settlements can be reached on acceptable terms or that adverse judgments, if any, in the remaining litigation will not exceed the amounts reserved. With the exception of the royalty lawsuit discussed below, and 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.

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 allegedly as representative of all royalty owners in the Company's West Virginia oil and gas wells, 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. On August 31, 2010, the federal judge issued an order remanding the case to state court. On October 27, 2010, the state court set a trial date of April 2012.

In April 2011, the Company entered into an oral settlement agreement with respect to this lawsuit. The oral settlement agreement has been approved by the Company's Board of Directors and involves the payment of a total of $8,750,000. The parties are currently drafting definitive documentation to reflect the oral agreement. There can be no assurance that such definitive documentation will be completed on terms satisfactory to the Company. A hearing has been set for June 6, 2011, for the court to consider preliminary approval of the settlement. For the three months ended 2011, the Company recorded a charge to general and administrative expense in the statement of operations of $1.6 million. As of March 31, 2011, the Company had the total oral settlement accrued and included in other accrued expenses on the accompanying balance sheet.

Environmental. Due to the nature of the natural gas and oil industry, we are exposed to environmental risks. We have various policies and procedures to avoid environmental contamination and mitigate the risks from environmental contamination. We conduct periodic reviews to identify changes in our environmental risk profile. Liabilities are accrued when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. As of March 31, 2011, and December 31, 2010, we had accrued environmental liabilities in the amount of $1.5 million and $1.7 million, respectively, included in other accrued expenses on the balance sheet. We are not aware of any environmental claims existing as of March 31, 2011, which have not been provided for or would otherwise have a material impact on our accompanying financial statements. However, there can be no assurance that current regulatory requirements will not change or unknown past non-compliance with environmental laws will not be discovered on our properties.

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, 2011, the maximum annual repurchase obligation for 2011, based upon the minimum price described above, was approximately $8.5 million. We believe we have adequate liquidity to meet this obligation. For the three months ended 2011, amounts paid for the repurchase 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 severance benefits.

If, within two years following a change of control of the Company ("change in control period"), either the Company terminates the executive officer without cause or the executive officer terminates employment for good reason (what is referred to as a "double trigger"), then the severance benefits owed equals 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, in the case of two executive officers, 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. Where the Company terminates the executive officer without cause or the executive officer terminates employment for good reason outside of the change in control period, the severance benefits range from two times to three times, specific to the executive officer, the benefits noted above. For this purpose, a change of control and good reason correspond to the respective definitions of change of control and good reason under IRC 409A and the supporting Treasury regulations, with some differences. Under any of the above circumstances, the executive officer is also entitled under his employment agreement to (i) vesting of any unvested equity compensation (excluding all long-term incentive 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 at the Company's cost for the federal COBRA health continuation coverage period 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 qualified retirement 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 a partial year bonus; incentive, deferred, retirement or other compensation; and to provide any other benefits, which have been earned or become payable as of the termination date.

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 and bonus, provided, however, that with respect to the bonus, for certain executive officers, there will 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 will 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 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 will (i) in the case of death be paid in a lump sum and be equal to the base salary that would otherwise have been paid for a six-month period following the termination date and (ii) in the case of disability be up to thirteen weeks of ongoing base salary plus a lump sum equal to six months of base salary.

Partnership Casualty Losses. As Managing General Partner of 29 partnerships, we have a potential liability for casualty losses in excess of the partnership assets and insurance. We believe the casualty insurance coverage that we and our subcontractors carry is adequate to meet this potential liability.

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NOTE 10 - STOCK-BASED COMPENSATION PLANS

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

	Three Months Ended March 31,	
	2011	2010
	(in thousands)	
Total stock-based compensation expense	$1,545	$1,005
Income tax benefit	(587)	(386)
Net income (loss) impact	$958	$619

Stock Appreciation Rights ("SARs")

The SARs will vest ratably over a three-year period and may be exercised at any point after vesting through March 2021. Pursuant to the terms of the awards, upon exercise, the executives will receive, in shares of common stock, the excess of the market price of the award on the date of exercise over the market price of the award on the date of issuance.

In March 2011, our Compensation Committee of our Board of Directors (the "Committee") awarded 31,552 SARs to our executive officers. The fair value of each SAR award was estimated on the date of grant using a Black-Scholes pricing model using the assumptions presented in the table below. The expected life of the award was estimated using historical stock option exercise behavior data. The risk-free interest rate was based on the U.S. Treasury yields approximating the expected life of the award in effect at the time of grant. Expected volatilities were based on our historical volatility. We do not expect to pay dividends, nor do we expect to declare dividends in the foreseeable future.

	Three Months Ended March 31, 2011
Expected term of the award	6 years
Risk-free interest rate	2.5 %
Volatility	60.2 %
Weighted average grant date fair value per share	$25.22

The following table presents the changes in our SARs for the three months ended 2011.

	Number of Shares Underlying SARs	Grant Date Market Price Per Share	Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2010	57,282	$24.44	9.3	$—
Awarded	31,552	43.95	10.0	—
Outstanding at March 31, 2011	88,834	31.37	9.4	1,478
	79,951	31.37	9.4	1,330

Vested and expected to vest at March 31, 2011				
Exercisable at March 31, 2011	—	—	—	—

The total compensation cost related to SARs granted and not yet recognized in our statement of operations as of March 31, 2011, was $1.2 million. The cost is expected to be recognized over a weighted average period of two years.

Restricted Stock Awards

Time-Based Awards. The following table presents the changes in non-vested time-based awards for the three months ended 2011. In March 2011, the Committee awarded a total of 43,256 time-based restricted shares to our executive officers that vest ratably over a three-year period ending on March 12, 2014.

The total compensation cost related to non-vested time-based awards expected to vest and not yet recognized in our statements of operations as of March 31, 2011, was $9.9 million. This cost is expected to be recognized over a weighted average period of 2.4 years.

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	Shares	Weighted Average Grant-Date Fair Value per Share
Non-vested at December 31, 2010	525,715	$25.53
Granted	48,173	43.95
Vested	(30,137)	29.26
Forfeited	(9,707)	23.39
Non-vested at March 31, 2011	534,044	27.02

	As of/Three Months Ended March 31, 2011 (in thousands, except per share data)
Total intrinsic value of time-based awards vested	$1,400
Total intrinsic value of time-based awards non-vested	25,639
Market price per common share as of March 31	48.01

Market-Based Awards. The fair value of the market-based awards is amortized ratably over the requisite service period, primarily three years. Generally, the market-based shares vest if the participant is continuously employed throughout the performance period and the market-based performance measure is achieved, with a maximum vesting period of five years. All compensation cost related to the market-based awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved.

In March 2011, the Committee awarded a total of 13,531 market-based restricted shares to our executive officers. In addition to continuous employment, the vesting of these shares is contingent on the Company's total shareholder return ("TSR"), which is essentially the Company’s stock price change including any dividends, as compared to the TSR of a set group of 11 peers. The shares are measured over a three-year period ending on December 31, 2013, and can result in a payout between zero and 200% of the total shares awarded. The weighted average grant date fair value per market-based share for these awards granted was computed using the Monte Carlo pricing model using the weighted average assumptions presented in the table below.

	Three Months Ended March 31, 2011
Expected term of award	3 years
Risk-free interest rate	1.1%
Volatility	74.2%
Weighted average grant date fair value per share	$58.53

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

The following table presents the change in non-vested market-based awards for the three months ended 2011.

	Shares	Weighted Average Grant-Date Fair Value per Share
Non-vested at December 31, 2010	79,550	$32.52
Granted	13,531	58.53
Non-vested at March 31, 2011	93,081	36.30

The total compensation cost related to non-vested market-based awards expected to vest and not yet recognized in our statement of operations as of March 31, 2011 was $0.8 million. This cost is expected to be recognized over a weighted average period of 2.7 years.

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NOTE 11 - EARNINGS PER SHARE

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

	Three Months Ended March 31,	
	2011	2010
	(in thousands)	
Weighted average common shares outstanding - basic	23,428	19,191
Dilutive effect of share-based compensation:		
Restricted stock	—	88
Non employee director deferred compensation	—	8
Weighted average common and common share equivalents outstanding - diluted	23,428	19,287

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,	
	2011	2010
	(in thousands)	
Weighted average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:		
Restricted stock	603	146
Stock options	10	10
SARs	64	—
Convertible debt	161	—
Non employee director deferred compensation	3	—
Total anti-dilutive common share equivalents	841	156

NOTE 12 - DIVESTITURES AND DISCONTINUED OPERATIONS

North Dakota. During the fourth quarter of 2010, we developed a plan to divest our North Dakota assets. The plan included 100% of our North Dakota assets, consisting of producing wells, undeveloped leaseholds and related facilities primarily located in Burke County. The plan received board approval and, in December 2010, we effected a letter of intent with an unrelated third party. Following the sale to the unrelated party, we do not have significant continuing involvement in the operations of or cash flows from these assets; accordingly, the North Dakota assets were reclassified as held for sale as of December 31, 2010, and the results of operations related to those assets have been separately reported as discontinued operations in the accompanying financial statements for both periods presented. In February 2011, we executed a purchase and sale agreement and subsequently closed with the same unrelated party. Proceeds from the sale were $9.5 million, net of affiliated partnerships' proceeds of $3.8 million, resulting in a pretax gain on sale of $3.9 million.

Selected financial information related to divested and discontinued operations. The table below presents selected operational information related to discontinued operations. While the reclassification of revenues and expenses related to discontinued operations for prior period had no impact upon previously reported net earnings, the statement of operations and operational data present the revenues, expenses and production volumes that were reclassified from the specified statement of operations line items to discontinued operations.

The following table presents statement of operations data related to our discontinued operations. The three months ended 2010 includes operations data related to the July 2010 divestiture of our Michigan assets.

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Statement of Operations - Discontinued Operations	Three Months Ended March 31, 2011	2010
	(dollars in thousands)	
Revenues		
Natural gas, NGL and crude oil sales	$447	$2,541
Sales from natural gas marketing	—	1,624
Well operations, pipeline income and other	10	256
Total revenues	457	4,421
Costs, expenses and other		
Production costs	132	715
Cost of natural gas marketing	—	1,531
Depreciation, depletion and amortization	—	931
Gain on sale of leaseholds	(3,854)	—
Total costs, expenses and other	(3,722)	3,177
Income from discontinued operations	4,179	1,244
Provision for income taxes	1,559	447
Income from discontinued operations, net of tax	$2,620	$797
Operational Data		
Production		
Natural gas (MMcf)	8.7	368.5
Crude oil (MBbls)	3.8	12.0
Natural gas equivalent (MMcfe)	31.5	440.4

NOTE 13 - TRANSACTIONS WITH AFFILIATES

Amounts due from/to the affiliated partnerships are primarily related to derivative positions and, to a lesser extent, unbilled well lease operating expenses, and costs resulting from audit and tax preparation services. We enter into derivative instruments for our own production as well as for our 29 affiliated partnerships' production. As of March 31, 2011, we had a payable to affiliates of $18.8 million representing their designated portion of the fair value of our gross derivative assets and a receivable from affiliates of $14.7 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. Our sales from natural gas marketing include $2.1 million and $1.1 million for the three months ended 2011 and 2010, respectively, related to the marketing of natural gas on behalf of PDCM and our affiliated partnerships. Our cost of natural gas marketing includes $2 million and $1.1 million for the three months ended 2011 and 2010, respectively, related to these sales.

We provide certain well operating and administrative services for PDCM. Amounts billed to PDCM for these services were $2.7 million in the three months ended 2011. Our statements of operations include only our proportionate share of these billings: $0.9 million, $0.1 million and $0.4 million are reflected in production costs, exploration expense and general and administrative expense, respectively.

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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NOTE 14 - BUSINESS SEGMENTS

We separate our operating activities into two segments: natural gas and crude 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.

	Three Months Ended March 31,	
	2011	2010
	(in thousands)	
Revenues:		
Natural gas and crude oil sales	$41,873	$103,635
Natural gas marketing	15,202	22,687
Unallocated	—	3
Total	$57,075	$126,325
Segment income (loss) before income taxes:		
Natural gas and crude oil sales	$(12,910)	$55,654
Natural gas marketing	209	357
Unallocated	(23,690)	(19,335)
Total	$(36,391)	$36,676

	March 31, 2011	December 31, 2010
	(in thousands)	
Segment assets:		
Natural gas and crude oil sales	$1,313,163	$1,313,805
Natural gas marketing	15,170	16,338
Unallocated	60,014	53,701
Assets held for sale	—	5,191
Total	$1,388,347	$1,389,035

NOTE 15 - SUBSEQUENT EVENTS

On May 6, 2011, the biannual redetermination of our corporate bank credit facility's borrowing base, which was based upon our natural gas and crude oil reserves as of December 31, 2010, was completed. Based on the redetermination, our aggregate revolving commitment was increased to $350 million from $321.2 million. There were no other changes to our corporate bank credit facility as a result of the redetermination.

On April 20, 2011, PDCM entered into the first amendment to its credit agreement dated April 30, 2010. Pursuant to the amendment, its borrowing base was increased to $40 million from $10 million based on its December 31, 2010, reserves. In addition to the increase in borrowing base, the first amendment permits PDCM to enter into swap agreements on new properties which were not included in the most recent reserve report and which have been producing for at least 30 days.

See Note 9, Commitments and Contingencies - Litigation, for a discussion of the oral settlement agreement reached with regard to our West Virginia royalty lawsuit.

PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

EXECUTIVE SUMMARY

Operational Overview

During the three months ended 2011, we continued to execute our strategy to focus capital spending on our liquid-rich properties. We drilled 44 operated wells and participated in 11 non-operated drilling projects, of which 17 were completed and turned in line. We also executed 59 refrac/recompletion projects on 31 wells in the Wattenberg Field. Of the 44 wells drilled, three were horizontal Niobrara in the Wattenberg Field and six were in the recently acquired Permian Basin, all of which were in-process as of March 31, 2011. Our focus in the more liquid-rich areas will maximize drilling returns, given the recent surge in crude oil prices, as we pursue our targeted natural gas/crude oil production mix ratio of 65/35.

Our joint venture, PDCM, completed three additional successful Marcellus wells and now have a total of six horizontal wells producing. Our drilled wells continue to define the optimum area for our Marcellus development.

Financial Overview

Production from continuing operations for the three months ended 2011 increased by 20.4% compared to the three months ended 2010. Sales revenues increased $6.1 million or 10.5% due to our increased production, which was offset in part by the decrease in our average natural gas price per Mcf of $1.63 or 34.6%.

During the three months ended 2011, as we began to execute our 2011 capital spending plan, we drew down our December 31, 2010, cash balance, resulting in an available liquidity of $317.2 million as of March 31, 2011, compared to $356.9 million as of December 31, 2010. The excess cash balance as of December 31, 2010, was attributable to our double tranche offering of common equity and convertible debt in November 2010. Available liquidity is comprised of cash, cash equivalents and funds available under our credit facility. With our strong liquidity position, we anticipate that 2011 will be a year of increased capital spending, focused on organic growth in the liquid-rich areas of our Wattenberg Field and the Permian Basin along with the proposed acquisitions of our affiliated partnerships. We believe that our 2011 capital budget, excluding acquisitions, combined with our investment in 2010, will grow our production from continuing operations by 19% in 2011, while increasing the liquids portion of our production as a percentage of our total production and thereby enabling us to benefit from the crude oil to natural gas price differential.

On May 6, 2011, we completed the redetermination of our corporate bank credit facility's borrowing base, resulting in an increase in our March 31, 2011, available liquidity by $28.8 million. Similarly, PDCM completed its redetermination on April 20, 2011, resulting in an increase its March 31, 2011, available liquidity by $30 million. See Note 15, Subsequent Events, to the accompanying condensed consolidated financial statements.

Non-U.S. GAAP Financial Measures

We use "adjusted cash flow from operations," "adjusted net income (loss) attributable to shareholders" and "adjusted EBITDA," non-U.S. 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 U.S. GAAP and should be considered in addition to, not as a substitute for, net income, cash flows from operations, investing or financing activities, nor as a liquidity measure or indicator of operating results or cash flows reported in accordance with U.S. GAAP. The non-U.S. 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-U.S. 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-U.S. GAAP Financial Measures below for a detailed description of these measures as well as a reconciliation of each to the nearest U.S. GAAP measure.

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Results of Operations

Summary Operating Results

The following table presents selected information regarding our operating results from continuing operations.

	Three Months Ended March 31,			
	2011	2010	Change	
	(dollars in thousands, except per unit data)			
Production (1)				
Natural gas (MMcf)	7,747.3	6,513.4	18.9	%
Crude oil (MBbls)	371.3	284.8	30.4	%
NGLs (MBbls)	166.9	149.1	11.9	%
Natural gas equivalent (MMcfe) (2)	10,976.6	9,116.4	20.4	%
Average MMcfe per day	122.0	101.3	20.4	%
Natural Gas, NGL and Crude Oil Sales				
Natural gas	$23,855	$30,647	(22.2	)%
Crude oil	32,517	20,951	55.2	%
NGLs	7,507	6,229	20.5	%
Total natural gas, NGL and crude oil sales	$63,879	$57,827	10.5	%
Realized Gain (Loss) on Derivatives, net (3)				
Natural gas	$6,899	$20,879	(67.0	)%
Crude oil	(3,111)	2,045	(252.1	)%
Total realized gain on derivatives, net	$3,788	$22,924	(83.5	)%
Average Sales Price (excluding gain/loss on derivatives)				
Natural gas (per Mcf)	$3.08	$4.71	(34.6	)%
Crude oil (per Bbl)	87.56	73.57	19.0	%
NGLs (per Bbl)	44.99	41.80	7.6	%
Natural gas equivalent (per Mcfe)	5.82	6.34	(8.2	)%
Average Sales Price (including gain/loss on derivatives)				
Natural gas (per Mcf)	$3.97	$7.91	(49.8	)%
Crude oil (per Bbl)	79.20	80.74	(1.9	)%
NGLs (per Bbl)	44.99	41.80	7.6	%
Natural gas equivalent (per Mcfe)	6.16	8.86	(30.5	)%
Average Lifting Cost (per Mcfe) (4)	$1.17	$0.97	20.6	%
Natural Gas Marketing (5)	$209	$364	(42.6	)%
Other Costs and Expenses				
Exploration expense	$2,151	$6,418	(66.5	)%
General and administrative expense	13,873	10,694	29.7	%
Depreciation, depletion and amortization	32,357	27,458	17.8	%

Interest Expense, net	$9,053	$7,795	16.1	%

Amounts may not recalculate 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 interest we own.
(2) Six Mcf of natural gas equals one Bbl of crude oil or NGL.
(3) Represents realized derivative gains and losses related to natural gas and crude oil sales segment, which do not include realized derivative gains and losses related to natural gas marketing.
(4) Represents lease operating expenses on a per unit basis.
(5) Represents sales from natural gas marketing, net of costs of natural gas marketing, including realized and unrealized derivative gains and losses related to natural gas marketing activities.

PETROLEUM DEVELOPMENT CORPORATION
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Natural Gas, NGL and Crude Oil Sales

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

	Three Months Ended March 31,			
	2011	2010	Percentage Change	
Production				
Natural gas (MMcf)				
Rocky Mountain Region (1)	6,787.5	5,873.2	15.6	%
Permian Basin (2)	81.1	—	*	
Appalachian Basin	866.9	630.5	37.5	%
Other	11.8	9.7	21.6	%
Total	7,747.3	6,513.4	18.9	%
Crude oil (MBbls)				
Rocky Mountain Region	320.0	284.1	12.6	%
Permian Basin (2)	50.1	—	*	
Appalachian Basin	1.1	0.7	57.1	%
Other	0.1	—	*	
Total	371.3	284.8	30.4	%
NGLs (MBbls)				
Rocky Mountain Region	147.5	148.0	(0.3	)%
Permian Basin (2)	18.1	—	*	
Other	1.3	1.1	18.2	%
Total	166.9	149.1	11.9	%
Natural gas equivalent (MMcfe)				
Rocky Mountain Region	9,592.0	8,465.5	13.3	%
Permian Basin (2)	490.7	—	*	
Appalachian Basin	873.7	634.8	37.6	%
Other	20.2	16.1	25.5	%
Total	10,976.6	9,116.4	20.4	%

* Percentage change is not meaningful or equal to or greater than 300%.
Amounts may not recalculate due to rounding.

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(1) Approximately 27.7% of the 15.6% , or 253 MMcf, increase in our natural gas production was the result of a settlement with a gas purchaser recorded during the three months ended 2011 related to prior years' volume imbalances.

(2) Our Permian Basin properties were acquired in July and November 2010.

PETROLEUM DEVELOPMENT CORPORATION
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	Three Months Ended March 31,			
Average Sales Price (excluding gain/loss on derivatives)	2011	2010	Percentage Change	
Natural gas (per Mcf)				
Rocky Mountain Region (1)	$2.92	$4.64	(37.1	)%
Permian Basin (2)	5.23	—	*	
Appalachian Basin	4.11	5.34	(23.0	)%
Other	2.56	3.22	(20.5	)%
Weighted average price	3.08	4.71	(34.6	)%
Crude oil (per Bbl)				
Rocky Mountain Region	89.67	73.55	21.9	%
Permian Basin (2)	74.39	—	*	
Appalachian Basin	76.00	79.18	(4.0	)%
Other	85.61	—	*	
Weighted average price	87.56	73.57	19.0	%
NGLs (per Bbl)				
Rocky Mountain Region	44.10	41.51	6.2	%
Permian Basin (2)	50.46	—	*	
Other	69.50	80.77	(14.0	)%
Weighted average price	44.99	41.80	7.6	%
Natural gas equivalent (per Mcfe)				
Rocky Mountain Region	5.74	6.41	(10.5	)%
Permian Basin	10.33	—	*	
Appalachian Basin	4.17	5.39	(22.6	)%
Other	6.39	7.29	(12.3	)%
Weighted average price	5.82	6.34	(8.2	)%

* Percentage change is not meaningful or equal to or greater than 300%.
Amounts may not recalculate due to rounding.

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(1) Approximately $1.3 million, or $0.19 per Mcf, in natural gas sales revenue was the result of a settlement with a gas purchaser recorded during the three months ended 2011 related to prior years' volume imbalances.

(2) Our Permian Basin properties were acquired in July and November 2010.

For the three months ended 2011, natural gas, NGL and crude oil sales revenue increased compared to the three months ended 2010 due to the following (in millions):

Increase in production	$12.9	
Increase in average crude oil price	5.2	
Increase in average NGL price	0.6	
Decrease in average natural gas price	(12.6	)
Total increase in natural gas, NGL and crude oil sales revenue	$6.1	

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Production Costs. Production costs include our lease operating expenses, production taxes, the cost to operate wells and pipelines for our affiliated partnerships and other third parties and certain production and engineering staff related overhead costs.

	Three Months Ended March 31,	
	2011	2010
	(in millions)	
Lease operating expenses	$12.8	$8.8
Production taxes	4.7	2.4
Costs of well operations and pipeline services	1.9	1.9
Overhead and other production expenses	1.6	1.9
Total production costs	$21.0	$15.0

Lease operating expenses. Lifting costs per Mcfe were $1.17 and $0.97 for the three months ended 2011 and 2010, respectively. A large component of the increase in our lease operating expenses was due to well workovers, which include an increase in tubing and casing repairs of $2 million and environmental remediation charges of $1.4 million.

Production taxes. Production taxes fluctuate with natural gas, NGL and crude oil sales. The $2.3 million increase in production taxes for the three months ended 2011 compared to the three months ended 2010 was primarily related to higher ad valorem rates in new areas of production, such as the Permian Basin, as well as in existing areas of production, such as certain Colorado counties. To a lesser degree, the increase in production taxes was also impacted by the 10.5% increase in natural gas, NGL and crude oil sales.

Commodity Price Risk Management, Net

We use various derivative instruments to manage fluctuations in natural gas and crude oil prices. We have in place a variety of floors, collars, fixed-price swaps and basis swaps on a portion of our estimated natural gas and crude oil production. Because we sell all of our physical natural gas and crude oil at similar prices to the indices inherent in our derivative instruments, we ultimately realize a price 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.

Commodity price risk management, net, includes realized gains and losses and unrealized mark-to-market changes in the fair value of the derivative instruments related to our natural gas and crude oil production. Commodity price risk management, net, does not include derivative transactions related to our natural gas marketing, which are included in sales from and cost of natural gas marketing.

See Note 3, Fair Value Measurements and Disclosures, and Note 4, Derivative Financial Instruments, to the accompanying condensed consolidated financial statements included in this report for additional details of our derivative financial instruments. See Item 3, Quantitative and Qualitative Disclosures About Market Risk, for a detailed presentation of our open derivative positions as of March 31, 2011.

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

	Three Months Ended March 31,	
	2011	2010

	(in millions)	
Commodity price risk management gain (loss), net:		
Realized gains (losses):		
Natural gas	$6.9	$20.9
Crude oil	(3.1)	2.0
Total realized gains, net	3.8	22.9
Unrealized gains (losses):		
Reclassification of realized gains included in prior periods unrealized	(3.3)	(21.1)
Unrealized gains (losses) for the period	(24.4)	41.4
Total unrealized gains (losses), net	(27.7)	20.3
Total commodity price risk management gain (loss), net	$(23.9)	$43.2

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Realized gains recognized in the three months ended 2011 are primarily the result of lower natural gas spot prices at settlement compared to the respective strike price of our natural gas derivative positions. Realized gains on natural gas, exclusive of basis swaps, were $9 million for the three months ended 2011. These gains were offset in part by a $2.1 million loss on our basis swap positions as the negative basis differential between NYMEX and CIG was narrower than the strike price of the basis positions. We realized a $3.1 million loss on our crude oil positions due to higher spot prices at settlement compared to the respective strike price. Unrealized losses during the three months ended 2011 are primarily related to the shifts in the forward curves and their impact on the fair value of our open positions. The significant shift upward in the crude oil curve resulted in an unrealized loss of $21.4 million during the three months ended 2011. Likewise, the shift upward in the natural gas curve and the narrowing of the basis curve resulted in a total unrealized loss of $3 million.

During the three months ended 2010, we recorded realized gains of $22.9 million as a result of natural gas and crude oil spot prices being lower at settlement compared to the respective strike price. During the three months ended 2010, we recorded unrealized gains of $41.4 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.

Natural Gas Marketing

Fluctuations in our natural gas marketing's income contribution are primarily due to fluctuations in natural gas prices, realized and unrealized (mark-to-market adjustments) gains and losses on derivative positions and, to a lesser extent, volumes sold and purchased.

The following table presents the components of sales from and costs of natural gas marketing.

	Three Months Ended March 31,	
	2011	2010
	(in millions)	
Sales from natural gas marketing		
Natural gas sales revenue	$15.1	$18.1
Realized derivative gain	1.1	1.1
Unrealized derivative gain (loss)	(1.0)	3.5
Total sales from natural gas marketing	15.2	22.7
Costs of natural gas marketing		
Costs of natural gas purchases	14.6	17.6
Realized derivative loss	1.0	1.1
Unrealized derivative loss (gain)	(0.9)	3.3
Other	0.3	0.3
Total costs of natural gas marketing	15.0	22.3
Natural gas marketing contribution margin	$0.2	$0.4

The decreases in natural gas sales revenue and costs of natural gas purchases for the three months ended 2011 compared to the three months ended 2010 were primarily related to a 22.3% decrease in the average natural gas price, offset in part by a 7% increase in volumes. For the three months ended 2011, we recorded net unrealized losses compared to net gains for the three months ended 2010 primarily due to the shift in the natural gas forward curve and its impact on the fair value of our open natural gas marketing derivative positions.

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. See Note 4, Derivative Financial Instruments, to our 2010 Form 10-K and Item 3, Quantitative and Qualitative Disclosures About Market Risk, included in this report for a discussion of how each derivative type impacts our cash flows and detailed presentation of our derivative positions as of March 31, 2011.

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Other Costs and Expenses

Exploration Expense

The following table presents the major components of exploration expense.

	Three Months Ended March 31,	
	2011	2010
	(in millions)	
Amortization of individually insignificant unproved properties	$0.5	$0.6
Exploratory dry hole costs	0.1	2.9
Geological and geophysical costs	0.9	1.0
Operating, personnel and other	0.7	1.9
Total exploration expense	$2.2	$6.4

Exploratory dry hole costs. For the three months ended 2010, exploratory dry hole costs included the fracturing and testing of several exploratory zones on a well drilled in the Piceance Basin.

Operating, personnel and other. The decrease in operating, personnel and other for the three months ended 2011 compared to the three months ended 2010 was primarily related to personnel changes as former exploration department personnel were refocused on development drilling or administrative activities.

General and Administrative Expense

General and administrative expense increased $3.2 million to $13.9 million for the three months ended 2011 compared to $10.7 million for the three months ended 2010. The increase was primarily due to an increase in payroll and payroll related expenses of $1.8 million, of which $0.7 million related to the refocus of our exploration department personnel, as well as a $1.6 million charge to legal fees related to the oral settlement agreement reached with regard to our West Virginia royalty lawsuit.

Depreciation, Depletion and Amortization

Natural gas and crude oil properties. DD&A expense for natural gas and crude oil properties increased $5.1 million for the three months ended 2011 compared to the three months ended 2010. The 20.4% increase in our production contributed $7 million to the increase, while the lower weighted average DD&A rate resulted in a decrease in DD&A expense of $1.9 million.

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

	Three Months Ended March 31,	
	2011	2010
	(per Mcfe)	
Rocky Mountain Region:		
Wattenberg Field	$3.26	$3.66
Grand Valley Field	2.54	2.45
Weighted average	2.82	2.97

Permian Basin	2.79	—
Appalachian Basin	2.52	2.64
Total weighted average	2.79	2.96

Non-natural gas and crude oil properties. Depreciation expense for non-natural gas and crude oil properties was $1.7 million for the three months ended 2011 compared to $1.9 million for the three months ended 2010.

Non-Operating Income/Expense

Interest Expense. The increase in interest expense for the three months ended 2011 compared to the three months ended 2010 is primarily related to an increase in debt issuance amortization expense of $0.8 million, as well as a higher average outstanding debt balance. The increase in our outstanding debt balance is primarily related to our November 2010 convertible debt issuance; however, this increase was reduced in part by a reduction in outstanding borrowings under our corporate bank credit facility as of March 31, 2011, which was unutilized compared to borrowings as of March 31, 2010.

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Provision/Benefit for Income Taxes

See Note 6, Income Taxes, to the accompanying condensed consolidated financial statements for a discussion of the changes in our effective tax rate during the three months ended 2011 compared to the three months ended 2010. Note that the comparison is between a tax benefit rate on a loss for the three months ended 2011 to a tax provision rate on income for the three months ended 2010. Due to tax interim period benefit limitations and the different effects of permanent tax adjustments, primarily percentage depletion, upon the current period tax benefit versus the prior year period tax provision, the comparison of these rates is less meaningful.

Beginning with our 2010 tax year, we were accepted into and have agreed to participate in the IRS Compliance Assurance Process ("CAP") program. As part of this program, we have agreed to an accelerated timeline for the IRS examination of our 2007, 2008 and 2009 tax years. This examination is expected to be completed during the second quarter of 2011. We have accepted an offer for continued participation in the IRS CAP program for our 2011 tax year.

Discontinued Operations

See Note 12, Divestitures and Discontinued Operations, to the accompanying condensed consolidated financial statements included in this report for additional information regarding the divestiture of our North Dakota and Michigan assets.

North Dakota. In December 2010, we effected a letter of intent with an unrelated third party, which provided for the sale of 100% of our North Dakota assets. In February 2011, we executed a purchase and sale agreement and subsequently closed with the same unrelated third party. Proceeds from the sale were $9.5 million, net of affiliated partnerships' proceeds of $3.8 million, resulting in a pretax gain on sale of $3.9 million. The operating results related to these assets were immaterial for the three months ended 2011 and 2010.

Michigan. In July 2010, we completed the sale of our Michigan assets. Operating results related to these assets were immaterial for the three months ended 2010.

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

Net loss attributable to shareholders for the three months ended 2011 was $19.9 million compared to net income of $23.7 million for the three months ended 2010. Adjusted net loss attributable to shareholders, a non-U.S. GAAP financial measure, for the three months ended 2011 was $2.7 million compared to an adjusted net income of $11.1 million for the three months ended 2010. The quarter-over-quarter changes in net income (loss) attributable to shareholders are discussed above, with the most significant change being related to commodity price risk management activities. This same reason for change similarly impacted adjusted net income (loss) attributable to shareholders, with the exception of the unrealized derivative gains and losses on derivatives, adjusted for taxes, as these amounts are not included in the total. See Reconciliation of Non-U.S. GAAP Financial Measures below, for a more detailed discussion of this non-U.S. GAAP financial measure.

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Financial Condition, Liquidity and Capital Resources

Historically, our primary sources of liquidity have been cash flows provided by operating activities and our corporate bank credit facility. More recently, as market conditions have permitted, we have utilized the debt and equity markets and engaged in asset monetization transactions as sources of financing.

Our primary source of cash flows provided by operating activities is the sale of natural gas, NGL and crude oil. Fluctuations in our operating cash flows are substantially driven by commodity prices and changes in our production volumes. Commodity prices have historically been volatile and we manage this volatility through our derivative program, which has also historically been a source of cash from operations. We enter into commodity derivative instruments with maturities of no greater than five years from the date of the instrument. For instruments that mature in two years or less, our debt covenants limit our holdings to 80% of our expected future production on total proved reserves (PDPs, PDNPs and PUDs). For instruments that mature greater than two years but no more than our designated maximum maturity, our debt covenants limit our holdings to 80% of our expected future production on PDPs. Therefore, we may still have significant fluctuations in our cash flows provided by operating activities due to the remaining non-hedged portion of our future production.

Our working capital fluctuates for various reasons, including, but not limited to, changes in the fair value of our commodity derivative instruments and due to our practice of utilizing excess cash to reduce the outstanding borrowings under our credit facility. At March 31, 2011, we had a working capital deficit of $20.2 million compared to a surplus of $16.2 million at December 31, 2010.

We ended March 2011 with cash and cash equivalents of $14.7 million and availability under our credit facility of $302.5 million, for a total liquidity position of $317.2 million compared to $356.9 million at December 31, 2010. The decrease in liquidity of $39.7 million, or 11.1%, was primarily due to capital expenditures of $71.1 million during the three months ended 2011, offset in part by cash flows provided by operating activities of $15.5 million and $9.5 million from the divestiture of our North Dakota assets in February 2011. With our current liquidity position and expected cash flows from operations, we believe that we have sufficient capital for operations and our planned uses of capital for the next twelve-month period.

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Capital Expenditures

2011 Capital Budget. We establish a capital plan each calendar year based on our development and exploration opportunities, liquidity position and the expected cash flows provided by operating activities for that year. We may revise our capital plan during the year as a result of acquisitions, drilling results, commodity prices, changes in our borrowing capacity and/or significant changes in cash flows. In January 2011, our Board of Directors approved our 2011 capital plan of $233 million, exclusive of the potential acquisitions. The plan provides for $205 million in developmental drilling, including recompletions and refractures, with the remaining $28 million for exploration, leasing and other capital needs. We believe, based on the current commodity price environment and our estimated 2011 production of 44.9 Bcfe, an increase of approximately 19% over 2010 production from continuing operations, that our cash flows provided by operating activities will fund the majority of our 2011 capital plan. As of March 31, 2011, we have accelerated our capital spending program due to the significant rise in crude oil prices. During the three months ended 2011, we completed 59 refractures/recompletions in our Wattenberg Field on 31 wells compared to a budget of 24. By taking advantage of the current pricing environment, we believe that we will be able to maximize profits while minimizing the payback period. Additionally, we began to withhold from certain of our affiliated partnerships, on a pro-rata basis, allocated to us, the managing general partner, and investor partners based on their proportional ownership interest, funds from distributable cash flows of the partnerships resulting from their current production. The funds retained will be utilized to refracture or recomplete partnership wells located in the Wattenberg Field.

Because production from our existing properties declines rapidly in the first few years of production, in order to grow our production, we need to continue to commit significant amounts of capital in 2012 and beyond. If capital is not available or is constrained in the future, we will be limited to our cash flows provided by operating activities and liquidity under our credit facility as the sources for funding our capital expenditures. We would not be able to maintain our current level of production and cash flows provided by operating activities if capital markets and commodity prices were to become depressed and/or the borrowing base on our credit facility was reduced. The occurrence of such an event may result in our election to defer a substantial portion of our planned capital expenditures for 2011 and beyond and could have a material negative impact on our operations in the future.

Partnership Acquisition Plan. We are the managing general partner of various public limited partnerships. In 2010, we disclosed our intent to pursue, beginning in the fall of 2010 and extending through the next three years, the acquisition of the limited partnership units (the “Acquisition Plan”) held by investor partners of the particular partnership other than those held by PDC or its affiliates (“non-affiliated investor partners”), in certain limited partnerships that PDC had previously sponsored. For additional information regarding our intent to pursue the acquisitions of our these partnerships, refer to the disclosure included in Items 2.02, 7.01 and/or 8.01 of our Forms 8-K dated March 4, 2010, June 9, 2010, July 15, 2010 and November 17, 2010. However, such information shall not, by reason of this reference, be deemed to be incorporated by reference in, or otherwise be deemed to be part of, this report. Under the Acquisition Plan, any existing or future merger offer will be subject to the terms and conditions of the related merger agreement, and such agreement does or will likely contemplate the partnership being merged with and into a wholly-owned subsidiary of PDC. Each such merger will also be subject to, among other things, us having sufficient available capital, the economics of the merger and the approval by a majority of the limited partnerships units held by the non-affiliated investor partners of each respective limited partnership. Consummation of any proposed merger of a limited partnership under the Acquisition Plan will result in the termination of the existence of that partnership and the right of non-affiliated investor partners to receive a cash payment for their limited partnership units in that partnership.

We expect that the acquisition of these partnerships will provide us with immediate growth in both production and proved reserves from assets with which we are familiar. We believe that these acquisitions will also allow us to realize operational benefits and cost synergies as well as the opportunity to identify, pursue and accelerate a refracture program of the wells acquired. See Note 9, Commitments and Contingencies – Merger Agreements, to the accompanying condensed consolidated financial statements included in this report for a discussion of the pending acquisition of the 2005 Partnerships. We expect to finance any future partnership acquisitions through the utilization of our corporate bank credit facility.

Financing Activities

We have experienced no impediments in our ability to access borrowings under our current corporate bank credit facility or the capital markets, as demonstrated by our November 2010 capital market transactions. We continue to monitor market events and circumstances and their potential impacts on each of the lenders that comprise our corporate bank credit facility. Our corporate bank credit facility 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 6, 2011, based on our May redetermination, our borrowing base was increased to $350 million from $321.2 million. Our next scheduled redetermination will be effective for November 2011. While we continually aim 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.

We have a shelf registration statement on Form S-3 filed with the SEC in November 2008 and declared effective by the SEC in January 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 ability to raise capital should the need arise, and to have the flexibility to raise such funds in one or more offerings should we perceive the market conditions to be favorable. As of March 31, 2011, we have $315.8 million available on our shelf, which we may utilize to raise future capital.

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We are subject to quarterly financial debt covenants on our corporate bank credit facility. Currently, our key credit facility debt covenants require that we maintain: 1) total debt of less than 4.25 times earnings before interest, taxes, DD&A expense and capital expenditures ("EBITDAX") and 2) an adjusted working capital ratio of at least 1.0 to 1.0. Our adjusted working capital ratio is calculated by reducing our current assets and liabilities by any impact of recording the fair value of our natural gas and crude oil derivative instruments and adding our available borrowings on our corporate bank credit facility to our current assets. The impact of any current portion of our debt is eliminated from the current liabilities, therefore any change in our available borrowings under our credit facility impacts our working capital ratio. We were in compliance with all debt covenants at March 31, 2011, and expect to remain in compliance throughout the next twelve-month period.

The indenture governing our senior notes contains customary representations and warranties as well as typical restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (a) incur additional debt, (b) make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) pay dividends or other payments by restricted subsidiaries, (e) create liens that secure debt, (f) enter into transactions with affiliates and (g) merge or consolidate with another company. Additionally, with regard to our 12% senior notes, we are subject to two incurrence covenants: 1) EBITDAX of at least two times interest expense and 2) total debt of less than 4.0 times EBITDAX. We were in compliance with all covenants at March 31, 2011, and expect to remain in compliance throughout the next twelve-month period.

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

Cash Flows

Operating Activities. Our cash flows provided by operating activities is primarily impacted by commodity prices, production volumes, realized gains and losses from our derivative positions, operating costs and general and administrative expenses. Cash flows provided by operating activities decreased for the three months ended 2011 compared to the three months ended 2010. The decrease was primarily due to our derivative positions providing a less favorable contribution to cash flows than the contribution made in the prior year period. See Results of Operations above for an additional discussion of the key drivers of cash flows provided by operating activities.

Natural gas, NGL and crude oil prices exhibit a high degree of volatility. These price variations have a material impact on our financial results. Natural gas and NGL prices vary by region and locality, depending upon the distance to markets, the availability of pipeline capacity and the supply and demand relationships in that region or locality. This can be especially true in the Rocky Mountain Region. The combination of increased drilling activity and the lack of local markets has resulted in local market oversupply situations 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. Crude oil pricing is predominately driven by the physical market, supply and demand, the financial markets and global unrest.

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 natural gas sold at, near or below CIG prices as well as other nearby region prices. The CIG Index and other indices for production delivered to other Rocky Mountain pipelines have historically been less than the price received for natural gas produced in the eastern regions, which is NYMEX-based. This negative differential has narrowed over the last few years and is lower than historical variances. The negative differential of CIG relative to NYMEX averaged $0.28 and $0.16 for the three months ended 2011 and 2010, respectively.

Adjusted cash flows from operations and adjusted EBITDA decreased for the three months ended 2011 compared to the three months ended 2010. These decreases 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-U.S. GAAP Financial Measures, below, for a more detailed discussion of these non-U.S. GAAP financial measures.

Investing Activities. Net cash used in investing activities was primarily related to the acquisition, exploration and development of natural gas and crude oil properties, net of dispositions of natural gas and crude oil properties. Capital expenditures for the three months ended 2011 increased significantly from those for the three months ended 2010.

Financing Activities. Cash flows provided by financing activities for the three months ended 2011 decreased compared to the three months ended 2010. The decrease is primarily related to our utilization of excess cash provided from our November 2010 capital raise and cash flows from operating activities to fund our capital expenditures and operating expenses for the period and therefore, it was not necessary for us to draw on our corporate bank credit facility. Additionally, for the three months ended 2011, financing cash flows include $6.4 million, representing our proportionate share, in capital contributions made to PDCM by our investing partner.

Drilling Activity

The following tables present our developmental 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 wells spudded, turned in line and producing during the period. In-process wells represent wells that have been spudded, drilled and are waiting to be completed and/or for gas pipeline connection during the period.

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	Gross Drilling Activity Three Months Ended March 31,			
	2011		2010	
	Productive	In-Process (1)	Productive	In-Process
Development Wells				
Rocky Mountain Region	17	31	20	23
Permian Basin	—	6	—	—
Total development wells	17	37	20	23
Exploratory Wells				
Rocky Mountain Region	—	1	—	—
Appalachian Basin	—	—	—	1
Total exploratory wells	—	1	—	1
Total drilling activity	17	38	20	24
Recompletions/refractures	31		11	

(1) As of March 31, 2011, a total of 50 wells, including the 38 wells drilled during the three months ended 2011 and still in-process as of March 31, were waiting to be completed and/or for pipeline connection.

	Net Drilling Activity Three Months Ended March 31,			
	2011		2010	
	Productive	In-Process	Productive	In-Process
Development Wells				
Rocky Mountain Region	9.3	24.6	17.9	20.0
Permian Basin	—	6.0	—	—
Total development wells	9.3	30.6	17.9	20.0
Exploratory Wells				
Rocky Mountain Region	—	1.0	—	—
Appalachian Basin	—	—	—	0.7
Total exploratory wells	—	1.0	—	0.7
Total drilling activity	9.3	31.6	17.9	20.7
Recompletions/refractures	28.9		10.5	

Off-Balance Sheet Arrangements

As of March 31, 2011, with the exception of those identified under Contractual Obligations and Contingent Commitments - Commitments, contingencies and other arrangements below, we had no existing off-balance sheet arrangements, as defined under SEC rules, that have or are reasonably likely to have a material current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Commitments and Contingencies

See Note 9, Commitments and Contingencies, to the accompanying condensed consolidated financial statements included in this report.

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Contractual Obligations and Contingent Commitments

The table below presents our contractual obligations and contingent commitments as of March 31, 2011.

	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 millions)				
Long-term liabilities reflected on the consolidated balance sheets (1)					
Long-term debt (2)	$318.0	$—	$—	$—	$318.0
Derivative contracts (3)	67.6	23.6	43.1	0.9	—
Derivative contracts - affiliated partnerships (4)	17.6	7.3	10.3	—	—
Production tax liability	36.6	16.1	20.5	—	—
Asset retirement obligations	28.2	0.2	0.4	0.8	26.8
Other liabilities (5)	9.9	0.3	3.7	0.6	5.3
	477.9	47.5	78.0	2.3	350.1
Commitments, contingencies and other arrangements (6)					
Interest on long-term debt (7)	195.1	30.1	59.3	58.6	47.1
Operating leases	8.2	2.1	3.5	2.6	—
Rig commitment (8)	5.3	3.4	1.9	—	—
Drilling commitment	0.9	—	—	—	0.9
Firm transportation and processing agreements (9)	173.3	19.8	46.3	37.8	69.4
Other	0.5	0.1	0.3	0.1	—
	383.3	55.5	111.3	99.1	117.4
Total	$861.2	$103.0	$189.3	$101.4	$467.5

(1) Table does not include deferred income tax liability to taxing authorities of $181.4 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 excludes $21.3 million in unamortized debt discount. See Note 7, Long-Term Debt, to the accompanying condensed consolidated financial statements included in this report.

(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 $14.7 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 an undrawn $18.7 million irrevocable standby letter of credit issued in August 2009 to a transportation service provider; see Note 7, Long-Term Debt, in the accompanying condensed consolidated financial statements included in this report. Additionally, the table does not include the annual repurchase obligations to investing partners of our affiliated partnerships or termination benefits related to employment agreements with our executive officers, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations; see Note 9, Commitments and Contingencies - Partnership Repurchase Provision;

Employment Agreements with Executive Offers, to the accompanying condensed consolidated financial statements included in this report.

(7) Amounts presented include $20.1 million payable to the holders of our 3.25% convertible senior notes due 2016 and $167.5 million to the holders of our 12% senior notes due 2018. Amounts also include $7.4 million payable to the participating banks of our revolving credit facility. As of March 31, 2011, there were no borrowings outstanding on our revolving bank credit facility; however, the $7.4 million represents amounts due on the unutilized commitment at a rate of 0.5% per annum plus a rate of 2.125% per annum related to our outstanding letter of credit.

(8) Drilling rig commitment in the above table reflects our proportionate share of the maximum obligation for the services of one drilling rig in the Appalachian Basin.

(9) Represents our gross commitment, including our proportionate share of PDCM. We will recognize in our financial statements our proportionate share based on our working interest; however, the costs of all volume shortfalls will be borne by PDC only. See Note 9, Commitments and Contingencies - Firm Transportation Agreements, to the accompanying condensed consolidated financial statements included in this report.

As the managing general partner of 29 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 and their potential impact on our condensed consolidated financial statements, see Note 9, Commitments and Contingencies – Litigation, to the accompanying condensed consolidated financial statements included in this report.

Recent Accounting Standards

See Note 2, Recent Accounting Standards, to the accompanying condensed consolidated financial statements included in this report.

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Critical Accounting Policies and Estimates

The preparation of the accompanying condensed 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.

There have been no 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 2010 Form 10-K.

Reconciliation of Non-U.S. GAAP Financial Measures

Adjusted cash flows from operations. We define adjusted cash flows 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 flows from operations as well as cash flows 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. See the condensed consolidated statements of cash flows in this report.

Adjusted net income (loss) attributable to shareholders. We define adjusted net income (loss) attributable to shareholders as net income (loss) attributable to shareholders plus unrealized derivative losses, provisions for underpayment of natural gas sales, minus unrealized derivative gains, each adjusted for tax effect. We believe it is important to consider adjusted net income (loss) 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.

Adjusted EBITDA. We define adjusted EBITDA as net income (loss) plus unrealized derivative loss, interest expense, net of interest income, provision for income taxes, and depreciation, depletion and amortization for the period minus unrealized derivative gain and benefit for income taxes. 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.

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

	Three Months Ended March 31,	
	2011	2010
	(in millions)	
Adjusted cash flows from operations:		
Adjusted cash flows from operations	$26.1	$49.3
Changes in assets and liabilities	(10.6)	2.0
Net cash provided by operating activities	$15.5	$51.3

Adjusted net income (loss) attributable to shareholders:		
Adjusted net income (loss) attributable to shareholders	$(2.7)	$11.1
Unrealized gain (loss) on derivatives, net	(27.7)	20.5
Tax effect of above adjustments	10.5	(7.9)
Net income (loss) attributable to shareholders	$(19.9)	$23.7
Adjusted EBITDA:		
Adjusted EBITDA	$36.9	$53.7
Unrealized gain (loss) on derivatives, net	(27.7)	20.5
Interest expense, net	(9.0)	(7.8)
Income tax benefit (expense)	12.3	(14.3)
Depreciation, depletion and amortization	(32.4)	(28.4)
Net income (loss) attributable to shareholders	$(19.9)	$23.7

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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

Changes in interest rates affect the amount of interest we earn on our cash, cash equivalents and restricted cash and the interest we pay on borrowings under our corporate bank credit facility. All of our other long-term indebtedness have a fixed rate and, therefore, near-term changes in interest rates do not expose us to risk of earnings or cash flow loss; however, near-term changes in interest rates may affect the fair value of our fixed-rate debt.

As of March 31, 2011, our interest-bearing deposit accounts included money market accounts, certificates of deposit and checking and savings accounts with various banks. The amount of our interest-bearing cash and cash equivalents as of March 31, 2011, was $21.4 million with an average interest rate of 0.4%. The $21.4 million represents our aggregate bank balances, which includes checks issued and outstanding. Based on a sensitivity analysis of our interest bearing deposits as of March 31, 2011, it was estimated that if market interest rates were to increase or decrease by 1%, the impact on our 2011 interest income would be immaterial.

As of March 31, 2011, with the exception of our undrawn $18.7 million irrevocable standby letter of credit, we had no outstanding borrowings on our corporate bank credit facility.

Commodity Price Risk

We are exposed to commodity price risk, the potential risk of loss from adverse changes in the market price of natural gas and crude oil commodities. We employ established policies and procedures to manage a portion of the risks associated with these market fluctuations using derivative instruments. These instruments allow us to predict with greater certainty the effective natural gas and crude oil prices to be received for our hedged production as it is produced. We believe that our established derivative policies and procedures are effective in achieving our risk management objectives for which they were intended.

Derivative Strategies. Our derivative strategies with regard to natural gas and crude oil sales and natural gas marketing are discussed below.

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

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The following table presents the derivative positions related to our natural gas and crude oil sales in effect as of March 31, 2011.

	Floors		Collars			Fixed-Price Swaps		CIG Basis Protection Swaps		
Commodity/ Index/ Maturity Period	Quantity (Oil - MBbls)	Weighted Average Contract Price	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted Average Contract Price Floors	Weighted Average Contract Price Ceilings	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted Average Contract Price	Quantity (BBtu) (1)	Weighted Average Contract Price	Fair Value March 31, 2011 (2) (in thousands)
Natural Gas										
NYMEX										
2011	—	$ —	—	$—	$—	9,322.8	$ 6.76	7,526.2	$ (1.81)	$10,375
2012	—	—	4,831.5	6.00	8.27	7,066.3	6.55	9,046.1	(1.80)	4,200
2013	—	—	4,438.1	6.10	8.60	5,461.0	6.78	8,159.7	(1.80)	1,509
2014	—	—	—	—	—	379.2	5.56	—	—	(59)
CIG										
2011	—	—	—	—	—	3,982.5	4.46	—	—	1,108
2012	—	—	—	—	—	700.0	4.11	—	—	(373)
2013	—	—	235.0	4.00	5.45	—	—	—	—	(63)
2014	—	—	1,115.0	4.50	5.67	—	—	—	—	(271)
2015	—	—	1,040.0	4.50	5.67	—	—	—	—	(500)
PEPL										
2011	—	—	—	—	—	2,615.8	5.64	—	—	3,423
2012	—	—	—	—	—	1,355.8	6.18	—	—	1,922
2013	—	—	—	—	—	990.4	6.18	—	—	1,113
Total Natural Gas	—		11,659.6			31,873.8		24,732.0		22,384
Crude Oil										
NYMEX										
2011	170.0	78.37	267.1	79.59	104.58	548.6	82.59	—	—	(16,693)
2012	36.0	65.38	643.6	81.53	94.63	444.0	81.60	—	—	(12,071)
2013	—	—	317.6	75.00	104.30	186.9	84.15	—	—	(6,581)
2014	—	—	36.0	90.00	106.15	—	—	—	—	(132)
2015	—	—	36.0	90.00	106.15	—	—	—	—	(99)
Total Crude Oil	206.0		1,300.3			1,179.5		—		(35,576)
Total Natural Gas and Crude Oil										$(13,192)

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(1) A standard unit of measurement for natural gas (one BBtu equals one MMcf).
(2) Approximately 31.5% of the fair value of our derivative assets and 99.4% of our derivative liabilities were measured using significant unobservable inputs (Level 3); see Note 3, Fair Value Measurements and

Disclosures, to the accompanying condensed consolidated financial statements.

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The following table presents our derivative positions related to our natural gas marketing in effect as of March 31, 2011.

Commodity/ Derivative Instrument/ Maturity Period	Fixed-Price Swaps Quantity (BBtu)(1)	Fixed-Price Swaps Weighted Average Contract Price	NYMEX Basis Protection Swaps Quantity (BBtu)(1)	NYMEX Basis Protection Swaps Weighted Average Contract Price	Fair Value March 31, 2011 (2) (in thousands)
Natural Gas					
Sales					
Physical					
2011	7.2	$5.60	40.6	$0.93	$33
2012	—	—	53.3	0.93	32
Financial					
2011	1,234.0	5.32	—	—	941
2012	629.0	4.81	—	—	(145)
2013	90.0	5.00	—	—	(45)
Purchases					
Physical					
2011	1,235.0	5.31	—	—	(738)
2012	629.0	4.79	—	—	233
2013	90.0	4.99	—	—	54
Financial					
2011	6.2	4.42	12.6	0.13	—
2012	—	—	30.4	0.13	(1)
Total Natural Gas	3,920.4		136.9		$364

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(1) A standard unit of measurement for natural gas (one BBtu equals one MMcf).

(2) Approximately 29.1% of the fair value of our derivative assets and 81.2% of our derivative liabilities were measured using significant unobservable inputs (Level 3); see Note 3, Fair Value Measurements and Disclosures, to the accompanying condensed consolidated financial statements.

The following table presents monthly average NYMEX and CIG closing prices for natural gas and crude oil for the periods identified, as well as average sales prices we realized for the respective commodities.

	Three Months Ended March 31, 2011	Year Ended December 31, 2010
Average Index Closing Price		
Natural Gas (per MMBtu)		
CIG	$3.83	$3.92
NYMEX	4.11	4.39
Crude Oil (per Bbl)		
NYMEX	90.41	77.32

Average Sales Price Realized		
Excluding realized derivative gains/(losses)		
Natural Gas (per Mcf)	$3.08	$3.61
Crude Oil (per Bbl)	87.56	74.03
Including realized derivative gains/(losses)		
Natural Gas (per Mcf)	3.97	5.12
Crude Oil (per Bbl)	79.20	79.62

Based on a sensitivity analysis as of March 31, 2011, it was estimated that a 10% increase in natural gas and crude oil prices, inclusive of basis, over the entire period for which we have derivatives then in place, including those designated to our affiliated partnerships, would result in a decrease in the fair value of our derivative positions of $45.2 million; whereas a 10% decrease in prices would result in an increase in fair value of $44.9 million. Excluding the derivatives designated to our affiliated partnerships, the same 10% increase or decrease in natural gas and crude oil prices would result in a decrease in fair value of $40.4 million and an increase in fair value of $40.1 million, respectively.

See Note 3, Fair Value Measurements and Disclosures, and Note 4, Derivative Financial Instruments, to the accompanying condensed consolidated financial statements included in this report for additional disclosure regarding our derivative financial instruments including, but not limited to, a summary of our open derivative positions as of March 31, 2011.

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.

With regard to our natural gas and crude oil sales segment, inherent to our industry is the concentration of natural gas, NGL and crude oil sales to a few customers. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic and financial conditions, commodity prices or other conditions. As for our natural gas marketing segment, 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. We monitor their creditworthiness through credit reports and rating agency reports. To date, we have had no material counterparty default losses in either of our natural gas and crude oil sales segment or natural gas marketing segment.

Our derivative financial instruments expose us to the credit risk of nonperformance by the counterparty to the contracts. We primarily use financial institutions, which are also major lenders in our credit facility, 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 from each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant.

Disruption 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 by a financial institution.

Disclosure of Limitations

Because the information above included only those exposures that exist as of March 31, 2011, 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 commodity price risk management strategies at the time, and interest rates and commodity prices at the time.

PETROLEUM DEVELOPMENT CORPORATION
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ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of March 31, 2011, 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 is 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 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, 2011.

Changes in Internal Control over Financial Reporting

During the three months ended 2011, we made no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II

ITEM 1. LEGAL PROCEEDINGS

Information regarding our legal proceedings can be found in Note 9, Commitments and Contingencies – Litigation, to the accompanying condensed consolidated financial statements included in this report.

ITEM 1A. RISK FACTORS

We face many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock are described under Item 1A, Risk Factors, of our 2010 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 2010 Form 10-K.

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	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs

			or Programs	
January 1 - 31, 2011	2,636	$42.72	—	—
February 1 - 28, 2011	1,095	46.96	—	—
March 1 - 31, 2011	8,143	47.56	—	—
Total	11,874	46.43		

(1) Purchases represent shares purchased by us from employees for the payment of their tax liabilities related to the vesting of securities issued pursuant to our stock-based compensation plans.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES - None

ITEM 4. [REMOVED AND RESERVED]

ITEM 5. OTHER INFORMATION - None

PETROLEUM DEVELOPMENT CORPORATION
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ITEM 6. EXHIBITS INDEX

With the exception of the following additions, there have been no material changes in the exhibits index previously disclosed in our 2010 Form 10-K.

		Incorporated by Reference				
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
10.1 *	2011 Executive Compensation, Short-Term Incentive Cash Bonus Program and Long-Term Incentive Compensation.	8-K	000-07246		3/17/2011	
10.2 *	Form of Performance Share Agreement.	8-K	000-07246	10.1	3/17/2011	
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, 2011

/s/ Richard W. McCullough
Richard W. McCullough,
Chairman and Chief Executive Officer
(principal executive officer)

/s/ Gysle R. Shellum
Gysle R. Shellum
Chief Financial Officer
(principal financial officer)

/s/ R. Scott Meyers
R. Scott Meyers
Chief Accounting Officer
(principal accounting officer)