PETROLEUM DEVELOPMENT CORP
Form 10-Q
May 10, 2012
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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, 2012

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 Website, 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 T 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: 23,665,459 shares of the Company's Common Stock ($0.01 par value) were outstanding as of April 20, 2012.

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PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This 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 ("U.S.") 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. These statements include: estimated natural gas, natural gas liquids ("NGLs") and crude oil production; future production levels and expenses, anticipated capital expenditures, including our ability to fund our 2012 capital budget; increased focus on the Wattenberg Field and liquid-rich areas and pursuing strategic and complementary acquisitions in Niobrara and Utica; our compliance with our debt covenants and the indenture restrictions governing our senior notes and expected continued compliance; the adequacy of our casualty insurance coverage as managing general partner of numerous partnerships and as operator of our own wells; the impact of decreased commodity prices on future borrowing base redeterminations; the effectiveness of our derivative policies in achieving our risk management objectives; the sufficiency of our monitoring procedures for the credit worthiness of our financial institutions; our expected remaining liability for uncertain tax positions; our ability to secure a joint venture partner for our Utica Shale acreage; the impact of outstanding legal issues; our ability to meet our partnership repurchase obligations, if applicable; our ability to benefit from crude oil and natural gas price differentials; and our strategies, plans and objectives.

The above statements 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, including economic conditions that might impact demand;
- volatility of commodity prices for natural gas, NGLs and crude oil;
- the impact of governmental fiscal terms and/or regulations, including changes in environmental laws, the regulation and enforcement related to those laws and the costs to comply with those laws, as well as other regulations;
- decline in the values of our natural gas and crude oil properties resulting in impairments;
- changes in estimates of proved reserves;
- inaccuracy of reserve estimates and expected production rates;
- the potential for production decline rates from our wells to be greater than expected;
- 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;
- the timing and receipt of necessary regulatory permits;
- risks incidental to the drilling and operation of natural gas and crude oil wells;
- our future cash flow, liquidity and financial position;
- competition in the oil and gas industry;
- the availability and cost of capital to us;
- reductions in the borrowing base under our credit facility;
- the availability of sufficient pipeline and other transportation facilities to carry our production and the impact of these facilities on price;
- our success in marketing natural gas, NGLs and crude oil;

- the effect of natural gas and crude oil derivatives activities;
- the impact of environmental events, governmental responses to the events and our ability to insure adequately against such events;
- the cost of pending or future litigation;
- the effect that acquisitions we may pursue have on our capital expenditures;
- our ability to retain or attract senior management and key technical employees; 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, 2011, filed with the United States Securities and Exchange Commission ("SEC") on March 1, 2012 ("2011 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.

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REFERENCES

Unless the context otherwise requires, references in this report to "PDC," "PDC Energy," "the Company," "we," "us," "our," "ours" or "ourselves" refer to the registrant, Petroleum Development Corporation, and all subsidiaries consolidated for the purposes of its financial statements, including our proportionate share of the financial position, results of operations, cash flows and operating activities of our affiliated partnerships and PDC Mountaineer, LLC ("PDCM"), a joint venture currently owned 50% each by PDC and Lime Rock Partners, LP formed for the purpose of exploring and developing the Marcellus Shale formation in the Appalachian Basin ("Marcellus JV"). Unless the context otherwise requires, references in this report to "Appalachian Basin" includes PDC's proportionate share of our affiliated partnerships' and the Marcellus JV's assets, results of operations, cash flows and operating activities.

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 subsidiaries.

References to "the three months ended 2012" refer to the three months ended March 31, 2012, as applicable. References to "the three months ended 2011" refer to the three months ended March 31, 2011, as applicable.

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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, 2012	December 31, 2011 (1)
Assets		
Current assets:		
Cash and cash equivalents	$1,655	$8,238
Restricted cash	2,315	11,070
Accounts receivable, net	64,019	59,923
Accounts receivable affiliates	9,534	8,518
Fair value of derivatives	74,778	60,809
Prepaid expenses and other current assets	7,672	24,492
Total current assets	159,973	173,050
Properties and equipment, net	1,329,460	1,301,716
Assets held for sale	—	148,249
Fair value of derivatives	36,751	41,175
Accounts receivable affiliates	2,147	2,836
Other assets	37,238	30,979
Total Assets	$1,565,569	$1,698,005
Liabilities and Equity		
Liabilities		
Current liabilities:		
Accounts payable	$56,152	$76,027
Accounts payable affiliates	11,682	10,176
Production tax liability	19,170	18,949
Fair value of derivatives	30,513	27,974
Funds held for distribution	30,093	28,594
Accrued interest payable	5,069	11,243
Other accrued expenses	12,583	22,083
Total current liabilities	165,262	195,046
Long-term debt	414,809	532,157
Deferred income taxes	198,082	207,573
Asset retirement obligations	45,172	46,316
Fair value of derivatives	25,815	21,106
Accounts payable affiliates	5,207	6,134
Other liabilities	29,990	25,561
Total liabilities	884,337	1,033,893
Commitments and contingent liabilities		
Shareholders' equity:		
Preferred shares, par value $0.01 per share; authorized 50,000,000	—	—

shares; issued: none		
Common shares, par value $0.01 per share; authorized 100,000,000 shares; issued: 23,659,339 in 2012 and 23,634,958 in 2011	237	236
Additional paid-in capital	219,139	217,707
Retained earnings	462,115	446,280
Treasury shares, at cost: 6,944 in 2012 and 2,938 in 2011	(259)	(111)
Total shareholders' equity	681,232	664,112
Total Liabilities and Equity	$1,565,569	$1,698,005

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(1) Derived from audited 2011 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,	
	2012	2011
Revenues:		
Natural gas, NGL and crude oil sales	$75,310	$58,810
Sales from natural gas marketing	11,834	15,202
Commodity price risk management gain (loss), net	11,501	(23,882)
Well operations, pipeline income and other	1,701	1,843
Total revenues	100,346	51,973
Costs, expenses and other:		
Production costs	19,189	18,472
Cost of natural gas marketing	11,492	14,993
Exploration expense	2,063	1,669
Impairment of natural gas and crude oil properties	653	453
General and administrative expense	14,708	13,873
Depreciation, depletion and amortization	39,814	30,985
Gain on sale of properties and equipment	(154)	—
Total costs, expenses and other	87,765	80,445
Income (loss) from operations	12,581	(28,472)
Interest income	2	9
Interest expense	(10,444)	(9,062)
Income (loss) from continuing operations before income taxes	2,139	(37,525)
Provision (benefit) for income taxes	759	(14,278)
Income (loss) from continuing operations	1,380	(23,247)
Income from discontinued operations, net of tax	14,455	3,323
Net income (loss)	$15,835	$(19,924)
Earnings (loss) per share:		
Basic		
Income (loss) from continuing operations	$0.06	$(0.99)
Income from discontinued operations	0.61	0.14
Net income (loss)	$0.67	$(0.85)
Diluted		
Income (loss) from continuing operations	$0.06	$(0.99)
Income from discontinued operations	0.60	0.14
Net income (loss)	$0.66	$(0.85)
Weighted average common shares outstanding		
Basic	23,609	23,428
Diluted	23,889	23,428

See accompanying Notes to Condensed Consolidated Financial Statements

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

	Three Months Ended March 31, 2012	2011
Cash flows from operating activities:		
Net income (loss)	$15,835	$(19,924)
Adjustments to net income to reconcile to net cash provided by operating activities:		
Unrealized (gain) loss on derivatives, net	(1,533)	27,745
Depreciation, depletion and amortization	39,814	32,357
Impairment of natural gas and crude oil properties	653	453
Exploratory dry hole costs	—	35
Loss (gain) from sale of properties and equipment	(20,489)	(3,928)
Deferred income taxes	10,914	(14,024)
Stock-based compensation	1,946	1,545
Amortization of debt discount and issuance costs	1,641	1,704
Other	699	136
Changes in assets and liabilities	(5,181)	(10,623)
Net cash provided by operating activities	44,299	15,476
Cash flows from investing activities:		
Capital expenditures	(107,029)	(71,079)
Acquisition of natural gas and crude oil properties	(10,000)	—
Proceeds from sale of properties and equipment	184,646	9,952
Other	—	(101)
Net cash provided by (used in) investing activities	67,617	(61,228)
Cash flows from financing activities:		
Proceeds from credit facility	144,750	—
Payment of credit facility	(263,000)	—
Contribution from noncontrolling interest	—	6,407
Other	(249)	(328)
Net cash provided by (used in) financing activities	(118,499)	6,079
Net decrease in cash and cash equivalents	(6,583)	(39,673)
Cash and cash equivalents, beginning of period	8,238	54,372
Cash and cash equivalents, end of period	$1,655	$14,699
Supplemental cash flow information:		
Cash payments (receipts) for:		
Interest, net of capitalized interest	$14,975	$12,314
Income taxes, net of refunds	(1,100)	85
Non-cash investing activities:		
Change in accounts payable related to purchases of properties and equipment	(21,044)	5,832
Change in asset retirement obligation, with a corresponding increase to natural gas and crude oil properties, net of disposals	(1,962)	229

See accompanying Notes to Condensed Consolidated Financial Statements

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PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
MARCH 31, 2012
(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, NGLs and crude oil. As of March 31, 2012, we owned an interest in approximately 6,500 gross wells located primarily in the Appalachian Basin, the Wattenberg Field, northeast Colorado and the Piceance Basin. We are engaged in two business segments: (1) Oil and Gas Exploration and Production and (2) Gas Marketing.

The accompanying unaudited condensed consolidated financial statements include the accounts of PDC, our wholly-owned subsidiaries, and our proportionate share of PDC Mountaineer, LLC ("PDCM") and 21 of our affiliated partnerships. Pursuant to the proportionate consolidation method, our accompanying consolidated 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.

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 2011 Form 10-K. The results of operations and the cash flows for the three months ended 2012 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. We reclassified the derivatives fair value hierarchy level of our PEPL and CIG-based natural gas fixed-price swaps, crude oil fixed-price swaps, basis swaps and natural gas physical purchases from Level 3 to Level 2. This reclassification had no impact on previously reported cash flows, net income, earnings per share or shareholders' equity.

NOTE 2 - RECENT ACCOUNTING STANDARDS

Recently Adopted Accounting Standards

Fair Value Measurement. On May 12, 2011, the FASB issued changes related to fair value measurement. The changes represent the converged guidance of the FASB and the International Accounting Standards Board ("IASB") on fair value measurement. Many of the changes eliminate unnecessary wording differences between International Financial Reporting Standards ("IFRS") and U.S. GAAP. The changes expand existing disclosure requirements for fair value measurements categorized in Level 3 by requiring (1) a quantitative disclosure of the unobservable inputs and assumptions used in the measurement, (2) a description of the valuation processes in place and (3) a narrative description of the sensitivity of the fair value to changes in unobservable inputs and the interrelationships between those inputs. In addition, the changes require the categorization by level in the fair value hierarchy of items that are not measured at fair value in the statement of financial position whose fair value must be disclosed. These changes are to be applied prospectively and are effective for public entities during interim and annual periods beginning after December 15, 2011. The adoption of these changes did not have a significant impact on our financial statements.

NOTE 3 - FAIR VALUE MEASUREMENTS AND DISCLOSURES

Derivative Financial Instruments

Determination of fair value. Our fair value measurements are estimated pursuant to a fair value hierarchy that requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability, and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels. The three levels of inputs that may be used to measure fair value are defined as:

Level 1 – Quoted prices (unadjusted) in active markets for identical assets or liabilities.

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

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Includes our natural gas and crude oil collars, crude oil puts and physical sales.

Derivative Financial Instruments. We measure the fair value of our derivative instruments based on a pricing model that utilizes market-based inputs, including but not limited to the contractual price of the underlying position, current market prices, natural gas and crude oil forward curves, discount rates such as the LIBOR curve for a similar duration of each outstanding position, volatility factors and nonperformance risk. Nonperformance risk considers the effect of our credit standing on the fair value of derivative liabilities and the effect of our counterparties' credit standings on the fair value of derivative assets. Both inputs to the model are based on published credit default swap rates and the duration of each outstanding derivative position.

We validate our fair value measurement through (1) the review of counterparty statements and other supporting documentation, (2) the determination that the source of the inputs is valid, (3) the corroboration of the original source of inputs through access to multiple quotes, if available, or other information and (4) monitoring changes in valuation methods and assumptions. While we use common industry practices to develop our valuation techniques, changes in our pricing methodologies or the underlying assumptions could result in significantly different fair values. While we believe our valuation method is appropriate and consistent with those used by other market participants, the use of a different methodology, or assumptions, to determine the fair value of certain financial instruments could result in a different estimate of fair value.

We have evaluated the credit risk of the counterparties holding our derivative assets, which are primarily financial institutions who are also major lenders in our corporate credit facility agreement, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant.

The following table presents, for each hierarchy level, our assets and liabilities, including both current and non-current portions, measured at fair value on a recurring basis.

	March 31, 2012			December 31, 2011		
	Significant other observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Significant other observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)					
Assets:						
Commodity based derivatives contracts	$84,707	$26,774	$111,481	$76,104	$25,837	$101,941
Basis protection derivative contracts	27	21	48	5	38	43
Total assets	84,734	26,795	111,529	76,109	25,875	101,984
Liabilities:						
Commodity based derivatives contracts	18,710	7,151	25,861	9,888	3,768	13,656
	30,467	—	30,467	35,424	—	35,424

Basis protection derivative contracts						
Total liabilities	49,177	7,151	56,328	45,312	3,768	49,080
Net asset	$35,557	$ 19,644	$55,201	$30,797	$ 22,107	$52,904

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

	Three Months Ended March 31,	
	2012	2011 (1)
	(in thousands)	
Fair value, net asset, beginning of period	$22,107	$10,762
Changes in fair value included in statement of operations line item:		
Commodity price risk management gain (loss), net	1,416	(9,885)
Sales from natural gas marketing	43	14
Changes in fair value included in balance sheet line item (2):		
Accounts receivable affiliates	—	49
Accounts payable affiliates	(52)	(654)
Settlements included in statement of operations line items:		
Commodity price risk management gain (loss), net	(3,797)	(2,910)
Sales from natural gas marketing	(73)	(75)
Fair value, net asset, end of period	$19,644	$(2,699)
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, net	$1,282	$(7,538)
Sales from natural gas marketing	3	(7)
	$1,285	$(7,545)

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(1) We reclassified our PEPL and CIG-based natural gas fixed-price swaps, crude oil fixed-price swaps, basis swaps and natural gas physical purchases from Level 3 to Level 2 (decreasing the previously reported net liability at the beginning of 2011 by $54.1 million). The amounts presented reflect these reclassifications and conform to current period presentation.

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

The significant unobservable input used in the fair value measurement of our derivative contracts is the implied volatility curve, and is provided by a third party vendor. A significant increase or decrease in the implied volatility, in isolation, would have a directionally similar effect resulting in a significantly higher or lower fair value measurement of our Level 3 derivative contracts.

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 liability associated with our non-qualified deferred compensation plan for non-employee directors may be settled in cash or shares of our common stock. The carrying value of this obligation is based on the quoted market price of our common stock, which is a Level 1 input. As of March 31, 2012, and December 31, 2011, the liability related to this plan was immaterial.

The portion of our long-term debt related to our corporate credit facility, as well as our proportionate share of PDCM's 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, 2012, we estimate the fair value of the portion of our long-term debt related to the 3.25% convertible senior notes due 2016 to be $127.9 million or 111.2% of par value and the portion related to our 12% senior notes due 2018 to be $220.3 million or 108.5% of par value. We determined these valuations based upon measurements of trading activity and broker and/or dealer quotes, respectively, which are published market prices and therefore Level 1 inputs.

NOTE 4 - DERIVATIVE FINANCIAL INSTRUMENTS

As of March 31, 2012, we had derivative instruments in place for a portion of our anticipated production through 2015 for a total of 72,997 BBtu of natural gas and 3,134 MBbls of crude oil.

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

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.

Derivatives instruments not designated as hedges (1):		Balance sheet line item	Fair Value March 31, 2012 (in thousands)	December 31, 2011
Derivative assets:	Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	$64,099	$51,220
	Related to affiliated partnerships (2)	Fair value of derivatives	8,959	8,018
	Related to natural gas marketing	Fair value of derivatives	1,691	1,528
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	29	43
			74,778	60,809
	Non Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	31,514	34,938
	Related to affiliated partnerships (2)	Fair value of derivatives	5,207	6,134
	Related to natural gas marketing	Fair value of derivatives	11	103
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	19	—
			36,751	41,175
Total derivative assets			$111,529	$101,984
Derivative liabilities:	Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	$10,492	$7,498
	Related to affiliated partnerships (3)	Fair value of derivatives	276	211
	Related to natural gas marketing	Fair value of derivatives	1,585	1,384
	Basis protection contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	15,166	15,762
	Related to affiliated partnerships (3)	Fair value of derivatives	2,992	3,116
	Related to natural gas marketing	Fair value of derivatives	2	3
			30,513	27,974
	Non Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	13,378	4,357
	Related to affiliated partnerships (3)	Fair value of derivatives	123	113
	Related to natural gas marketing	Fair value of derivatives	7	93

	Basis protection contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	10,281	13,820
	Related to affiliated partnerships (3)	Fair value of derivatives	2,024	2,723
	Related to natural gas marketing	Fair value of derivatives	2	—
			25,815	21,106
Total derivative liabilities			$56,328	$49,080

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(1) As of March 31, 2012, and December 31, 2011, none of our derivative instruments were designated as hedges.

(2) Represents derivative positions designated to our affiliated partnerships; accordingly, our accompanying balance sheets include a corresponding payable to our affiliated partnerships representing their proportionate share of the derivative assets.

(3) Represents derivative positions designated to our affiliated partnerships; accordingly, our accompanying balance sheets include a corresponding receivable from our affiliated partnerships representing their proportionate share of the derivative liabilities.

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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,					
	2012			2011		
Statement of operations line item	Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	Realized and Unrealized Gains (Losses) For the Current Period	Total	Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	Realized and Unrealized Gains (Losses) For the Current Period	Total
	(in thousands)					
Commodity price risk management gain, net						
Realized gains	$8,628	$1,299	$9,927	$3,322	$466	$3,788
Unrealized gains (losses)	(8,628)	10,202	1,574	(3,322)	(24,348)	(27,670)
Total commodity price risk management gain (loss), net	$—	$11,501	$11,501	$—	$(23,882)	$(23,882)
Sales from natural gas marketing						
Realized gains	$684	$109	$793	$1,007	$135	$1,142
Unrealized gains (losses)	(684)	759	75	(1,007)	(10)	(1,017)
Total sales from natural gas marketing	$—	$868	$868	$—	$125	$125
Cost of natural gas marketing						
Realized losses	$(591)	$(154)	$(745)	$(770)	$(190)	$(960)
Unrealized gains (losses)	591	(707)	(116)	770	172	942
Total cost of natural gas marketing	$—	$(861)	$(861)	$—	$(18)	$(18)

Derivative Counterparties. A significant portion of our liquidity is concentrated in derivative instruments that enable us to manage a portion of our exposure to price volatility from producing 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 is not significant.

The following table presents the counterparties that expose us to credit risk as of March 31, 2012, with regard to our derivative assets.

Counterparty Name	Fair Value of Derivative Assets As of March 31, 2012 (in thousands)

JPMorgan Chase Bank, N.A. (1)	$55,769
Crèdit Agricole CIB (1)	19,441
Wells Fargo Bank, N.A. (1)	20,099
Other lenders in our credit facility	16,135
Various (2)	85
Total	$111,529

(1)Major lender in our credit facility, see Note 7.
(2)Represents a total of 10 counterparties.

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NOTE 5 - PROPERTIES AND EQUIPMENT

The following table presents the components of properties and equipment, net of depreciation and assets held-for-sale.

	March 31, 2012	December 31, 2011
	(in thousands)	
Properties and equipment, net:		
Natural gas and crude oil properties		
Proved	$1,738,596	$1,694,694
Unproved	132,499	102,466
Total natural gas and crude oil properties	1,871,095	1,797,160
Pipelines and related facilities	42,062	40,721
Transportation and other equipment	32,878	32,475
Land and buildings	13,872	14,572
Construction in progress	61,584	69,633
Gross properties and equipment	2,021,491	1,954,561
Accumulated DD&A	(692,031)	(652,845)
Properties and equipment, net	$1,329,460	$1,301,716

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 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 2012 was a 35.5% provision on income compared to a 38.1% benefit on loss for the three months ended 2011. The effective tax rate for the three months ended 2012 differs from the statutory rate primarily due to net permanent deductions, largely percentage depletion partially offset by nondeductible officer's compensation. The effective tax rate for the three months ended 2011 differs from the statutory rate primarily due to net permanent deductions, largely percentage depletion, increasing the tax benefit on pretax loss. There were no significant discrete items recorded during each of the three months ended 2012 or 2011.

As of March 31, 2012, we had a gross liability for unrecognized tax benefits of $0.2 million, unchanged from the amount recorded at December 31, 2011. If recognized, all of this liability would affect our effective tax rate. This liability is reflected in other accrued expenses on our accompanying balance sheet. We do not expect our remaining liability for uncertain tax positions to decrease in the next twelve months.

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, 2012	December 31, 2011
	(in thousands)	
Senior notes		
3.25% Convertible senior notes due 2016:		
Principal amount	$115,000	$115,000
Unamortized discount	(16,250)	(17,079)
3.25% Convertible senior notes due 2016, net of discount	98,750	97,921
12% Senior notes due 2018:		
Principal amount	203,000	203,000
Unamortized discount	(1,691)	(1,764)
12% Senior notes due 2018, net of discount	201,309	201,236
Total senior notes	300,059	299,157
Credit facilities		
Corporate	82,000	209,000
PDCM	32,750	24,000
Total credit facilities	114,750	233,000
Total long-term debt	$414,809	$532,157

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. 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%. Upon conversion, the convertible notes may be settled, at our election, in shares of our common stock, cash or a combination of cash and shares of our common stock. 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, 2012, and expect to remain in compliance throughout the next twelve-month period.

Bank Credit Facilities

Corporate Bank Credit Facility. We operate under a credit facility dated November 5, 2010, as amended last on October 12, 2011, with an aggregate revolving commitment or borrowing base of $400 million (as recently increased to $425 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 quantification 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 and our subsidiaries' natural gas and crude oil interests, excluding proved reserves attributable to PDCM and our 21 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 and such subsidiaries' 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. See Note 15, Subsequent Events, for a discussion on our most recent borrowing base redetermination.

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, 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 falls below the outstanding balance. The credit facility contains covenants customary for agreements of this type.

We have outstanding an $18.7 million irrevocable standby letter of credit in favor of a third party transportation service provider to secure the construction of certain additions and/or replacements to its facilities to provide firm transportation of the natural gas produced by us and others for whom we market production in the Appalachian Basin. This letter of credit reduced 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, 2012) for the period the letter of credit remains outstanding. The letter of credit expires on July 20, 2012.

As of March 31, 2012, we had an outstanding balance of $82 million on our credit facility compared to $209 million as of December 31, 2011. 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, 2012, the available funds under our credit facility, including a reduction for the $18.7 million irrevocable standby letter of credit in effect, was $299.3 million. The weighted average borrowing rate on our credit facility, exclusive of the letter of credit, was 3.9% per annum as of March 31, 2012 compared to 3.8% as of December 31, 2011.

PDCM Credit Facility. PDCM has a credit facility dated April 30, 2010, as amended last on November 18, 2011, with an aggregate revolving commitment or borrowing base of $80 million, of which our proportionate share would be $40 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, 2012, our proportionate share of PDCM's outstanding credit facility draw was $32.8 million compared to $24 million as of December 31, 2011. PDCM pays a fee of 0.5% per annum on the unutilized commitment on the available funds under this credit facility.

As of March 31, 2012, 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, 2011	$46,566
Obligations incurred with development activities	99
Accretion expense	818
Obligations discharged with disposal of properties and asset retirements	(2,061)
Balance at March 31, 2012	45,422
Less current portion	(250)
Long-term portion	$45,172

NOTE 9 - COMMITMENTS AND CONTINGENCIES

Firm Transportation Agreements. We enter 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 includes volumes produced by us, volumes purchased from third parties and volumes produced by PDCM and affiliated partnerships. We record in our financial statements only our share of costs based upon our working interest in the wells; however, with the exception of contracts entered into by PDCM, the costs of all volume shortfalls will be borne by PDC.

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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	2013	2014	2015	2016	2017 Through Expiration	Total	Expiration Date
Volume (MMcf)							
Piceance Basin	17,951	36,126	34,656	29,407	104,851	222,991	May 31, 2021
Appalachian Basin (1)	15,572	20,117	22,630	23,856	183,965	266,140	September 25, 2025
NECO	3,195	1,825	1,825	1,825	1,370	10,040	December 31, 2016
Total	36,718	58,068	59,111	55,088	290,186	499,171	
Dollar commitment (in thousands)	$16,818	$28,415	$28,146	$25,635	$121,056	$220,070	

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(1) Includes a precedent agreement that becomes effective when a planned pipeline is placed in service, currently expected to be September 2012, and represents 6,173 MMcf of the total MMcf presented for the twelve months ending March 31, 2013, 10,627 MMcf for each of the twelve months ending March 31, 2014 through 2016, respectively, and 68,277 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 for 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. Although the results cannot be known with certainty, we currently believe that the ultimate results of such proceedings will not have a material adverse effect on our financial position, results of operations or liquidity.

Alleged Class Action Filed Regarding 2010 and 2011 Partnership Purchases

On December 21, 2011 the Company and its wholly-owned merger subsidiary were served with an alleged class action on behalf of certain former partnership unit holders, related to 11 partnership repurchases completed by mergers in 2010 and 2011. The action was filed in United States ("U.S.") District Court for the Central District of California, and is titled Schulein v. Petroleum Development Corp. The complaint alleges a claim that the proxy statements issued in connection with the mergers were inadequate, and a state law breach of fiduciary duty claim. On February 10, 2012, the Company filed a motion to dismiss or in the alternative to stay. The motion was argued on April 2, 2012. The Court has not filed a ruling at this time. The case is set for a scheduling conference on June 11, 2012. We believe the suit is without merit and we intend to defend vigorously.

Royalty Owner Class Action

Gobel et al v. Petroleum Development Corporation, filed on January 27, 2009, in Circuit Court of Harrison County, CA No. 09-C-40-2

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 allegations stated that the Company improperly deducted certain charges and costs before applying the royalty percentage. Punitive damages were requested in addition to breach of contract, tort and fraud allegations.

In April 2011, the Company entered into an oral settlement agreement with respect to this lawsuit, settling all claims between the parties for an aggregate payment of $8.7 million. On June 15, 2011, subject to court approval, a written settlement agreement was signed confirming these terms. On June 30, 2011, the state court granted initial approval of the settlement agreement, subject to notice to class members and final court approval. Initial notice was then sent to the class members. The date for objection by class members was October 24, 2011, with no objections received. Final approval and settlement occurred in January 2012 and as a result our restricted cash and accrued liability were reduced by the settlement amount.

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 damages resulting from past events are probable and the costs can be reasonably estimated. As of March 31, 2012 and December 31, 2011, we had accrued environmental liabilities in the amount of $1.7 million and $2.5 million, respectively, included in other accrued expenses on the balance sheet. We are not aware of any environmental claims existing as of March 31, 2012 which have not been provided for or would otherwise have a material impact on our 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 whereby 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, 2012, the maximum annual repurchase obligation, based upon the minimum price described above, was approximately $5.3 million. We believe we have adequate liquidity to meet this obligation. For the three months ended 2012, 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 executive officers. The employment agreements provide for annual base salaries, eligibility for performance bonus compensation and other various benefits, including severance benefits.

If, within two years following a change in 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, 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 one executive officer, paid or payable during the same two-year period. Mr. Trimble became President and Chief Executive Officer in June 2011 and under his employment agreement, if he is terminated without cause, he is to receive payment of salary and bonus through June 30, 2013, provided such amount will equal at least one year's salary and bonus. 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 Section 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) continued coverage under our medical plan at the Company's cost for the federal COBRA health continuation coverage period and (iv) 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 payment 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, 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 one executive officer, 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 officer is entitled to receive certain benefits. For this purpose, the definition of "disability" corresponds to the definition under IRC Section 409A and the supporting Treasury regulations. The benefits will (i) in the case of death of the executive officer other than the Chief Executive Officer, 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.

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NOTE 10 - COMMON STOCK

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,	
	2012	2011
	(in thousands)	
Total stock-based compensation expense	$1,946	$1,545
Income tax benefit	(741)	(587)
Net expense	$1,205	$958

Stock Appreciation Rights ("SARs")

The SARs will vest ratably over a three-year period and may be exercised at any point after vesting through 10 years from the date of issuance. Pursuant to the terms of the awards, upon exercise, the executive officers 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 2012, the Compensation Committee of our Board of Directors (the "Committee") awarded 68,361 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,	
	2012	2011
Expected term of the award	6 years	6 years
Risk-free interest rate	1.1%	2.5%
Volatility	64.3%	60.2%
Weighted average grant date fair value per share	$17.61	$25.22

The following table presents the changes in our SARs.

Three Months Ended March 31,							
2012				2011			
Number of SARs	Weighted Average Exercise	Average Remaining Contractual	Aggregate Intrinsic Value	Number of SARs	Weighted Average Exercise	Average Remaining Contractual	Aggregate Intrinsic Value

		Price	Term (in years)	(in thousands)		Price	Term (in years)	(in thousands)
Outstanding beginning of year, January 1	50,471	$31.61	8.6	$ 341	57,282	$24.44	9.3	$ 1,020
Awarded	68,361	30.19	9.8	—	31,552	43.95	10.0	—
Outstanding at March 31,	118,832	30.80	9.2	875	88,834	31.37	9.4	1,478
Vested and expected to vest at March 31,	111,137	30.76	9.2	825	79,951	31.37	9.4	1,330
Exercisable at March 31,	16,822	31.61	8.4	135	—	—	—	—

The total compensation cost related to SARs granted and not yet recognized in our statement of operations as of March 31, 2012 was $1.5 million. The cost is expected to be recognized over a weighted average period of 2.5 years.

Restricted Stock Awards

Time-Based Awards. In January 2012, the Committee awarded a total of 79,889 time-based restricted shares to our executive officers that vest ratably over a three-year period ending on January 16, 2015.

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, 2012 was $12 million. This cost is expected to be recognized over a weighted average period of 2.4 years.

The following table presents the changes in non-vested time-based awards for the three months ended 2012.

	Shares	Weighted Average Grant-Date Fair Value per Share
Non-vested at December 31, 2011	527,801	$29.29
Granted	101,252	31.23
Vested	(30,543)	31.74
Forfeited	(7,576)	26.47
Non-vested at March 31, 2012	590,934	29.58

	As of / Three Months Ended March 31,	
	2012	2011
	(in thousands, except per share data)	
Total intrinsic value of time-based awards vested	$1,104	$1,400
Total intrinsic value of time-based awards non-vested	21,918	25,629
Market price per common share as of March 31	37.09	48.01
Weighted average grant date fair value per share	31.23	43.95

Market-Based Awards. The fair value of the market-based restricted shares 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 2012, the Committee awarded a total of 30,541 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 15 peer companies. The shares are measured over a three-year period ending on December 31, 2014, 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,	
	2012	2011

Expected term of award	3 years	3 years
Risk-free interest rate	0.3 %	1.1 %
Volatility	65.3 %	74.2 %
Weighted average grant date fair value per share	$36.54	$58.53

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

The following table presents the change in non-vested market-based awards for the three months ended 2012.

	Shares	Weighted Average Grant-Date Fair Value per Share
Non-vested at December 31, 2011	43,081	$42.05
Granted	30,541	36.54
Non-vested at March 31, 2012	73,622	41.87

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, 2012, was $1.2 million. This cost is expected to be recognized over a weighted average period of 2.5 years.

Treasury Share Purchases

In accordance with our stock-based compensation plans, employees and directors may surrender shares of the Company's common stock to cover tax withholding obligations upon the vesting and exercise of share-based awards. The shares acquired may be retired or reissued to service awards under our 2010 Long-Term Equity Compensation Plan (the "2010 Plan"). For shares that are retired, we first charge any excess of cost over the par value to additional paid-in-capital ("APIC") to the extent we have amounts in APIC, with any remaining excess cost charged to retained earnings. For shares reissued to service awards under the 2010 Plan, shares are recorded at cost and upon reissuance, we reduce the carrying value of shares acquired and held pursuant to the 2010 Plan by the weighted average cost per share with an offsetting charge to APIC. During the three months ended March 31, 2012, we acquired 10,035 shares pursuant to our stock-based compensation plans for payment of tax liabilities, of which 6,162 shares were retired and the remaining 3,873 shares are available for reissuance pursuant to our 2010 Plan.

NOTE 11 - EARNINGS PER SHARE

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

	Three Months Ended March 31, 2012	2011
	(in thousands)	
Weighted average common shares outstanding - basic	23,609	23,428
Dilutive effect of share-based compensation:		
Restricted stock	212	—
SARs	65	—
Non employee director deferred compensation	3	—
Weighted average common and common share equivalents outstanding - diluted	23,889	23,428

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,	
	2012	2011
	(in thousands)	
Weighted average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:		
Restricted stock	27	603
Stock options	7	10
SARs	19	64
Convertible debt	—	161
Non employee director deferred compensation	—	3
Total anti-dilutive common share equivalents	53	841

In November 2010, we issued 115,000 convertible senior notes, $1,000 principal amount, that give the holders the right to convert the principal amount into 2.7 million common shares at a conversion price of $42.40 per share. The convertible notes could have a dilutive impact on our earnings per share if the average market share price exceeds the conversion price. The average price did not exceed $42.40 per share during the three months ended 2012 or 2011.

NOTE 12 - DIVESTITURES AND DISCONTINUED OPERATIONS

Permian Basin. In October 2011, we developed a plan to divest our Permian Basin assets. The plan included 100% of our Permian Basin assets, consisting of producing wells and undeveloped leaseholds. During the fourth quarter of 2011, we completed the sale of our non-core Permian assets to unrelated third parties for a total of $13.2 million. On December 20, 2011, we executed a purchase and sale agreement which was approved by our Board of Directors (the "Board"), with COG Operating LLC (“COG”), a wholly owned subsidiary of Concho Resources Inc., an unrelated third party, for the sale of our core Permian Basin assets for a sale price of $173.9 million, subject to customary terms and adjustments, including adjustments based on title and environmental due diligence to be conducted by COG. The effective date of the transaction was November 1, 2011. Following the sale to COG, we do not have significant continuing involvement in the operations of or cash flows from these assets; accordingly, the Permian assets were reclassified as held for sale as of December 31, 2011, and the results of operations related to those assets have been separately reported as discontinued operations in the condensed consolidated statement of operations for all periods presented. On February 28, 2012, the divestiture closed with total proceeds received of $184.4 million after preliminary closing adjustments, resulting in a pretax gain on sale of $20.3 million.

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 approval from our Board and, in December 2010, we effected a letter of intent with an unrelated third party. 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 non-affiliated investor partners' share of $3.8 million, resulting in a pretax gain on sale of $3.9 million. 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 results of operations related to the North Dakota assets have been reported as discontinued operations in the condensed consolidated statement of operations for the three months ended 2011.

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 the prior period had no impact upon previously reported net earnings, the statement of operations table below presents the revenues and expenses that were reclassified from the specified statement of operations line items to discontinued operations. The three months ended 2011, in addition to the discontinued operations data of our Permian assets, includes operations data related to the February 2011 divestiture of our North Dakota assets.

	Three Months Ended March 31,	
Statement of Operations - Discontinued Operations	2012	2011
	(dollars in thousands)	
Revenues		
Natural gas, NGL and crude oil sales	$4,456	$5,516
Well operations, pipeline income and other	34	43

Total revenues	4,490	5,559
Costs, expenses and other		
Production costs	1,668	2,699
Exploration expense	—	29
Depreciation, depletion and amortization	—	1,372
Gain on sale of properties and equipment	(20,335)	(3,854)
Total costs, expenses and other	(18,667)	246
Income from discontinued operations	23,157	5,313
Provision for income taxes	8,702	1,990
Income from discontinued operations, net of tax	$14,455	$3,323

NOTE 13 - TRANSACTIONS WITH AFFILIATES AND OTHER RELATED PARTIES

Affiliated Partnerships. Our Gas Marketing segment markets the natural gas produced by our affiliated partnerships in the Eastern Operating Region. Our sales from natural gas marketing include $0.1 million and $0.2 million for the three months ended 2012 and 2011, respectively, related to the marketing of natural gas on behalf of our affiliated partnerships. Our cost of natural gas marketing includes $0.1 million and $0.2 million for the three months ended 2012 and 2011, respectively, related to these sales.

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 have entered into derivative instruments on behalf of our 21 affiliated partnerships for their estimated production. As of March 31, 2012 and December 31, 2011, we had a payable to affiliates of $14.2 million, representing their designated portion of the fair value of our gross derivative assets; and a receivable from affiliates of $5.4 million and $6.2 million, respectively, representing their designated portion of the fair value of our gross derivative liabilities.

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.

PDCM. Our Gas Marketing segment markets the natural gas produced by PDCM. Our sales from natural gas marketing include $2.4 million and $1.8 million for the three months ended 2012 and 2011, respectively, related to the marketing of natural gas on behalf of PDCM. Our cost of natural gas marketing includes $2.4 million and $1.8 million for the three months ended 2012 and 2011, respectively, related to these sales.

We provide certain well operating and administrative services for PDCM. Amounts billed to PDCM for these services were $3.2 million and $2.7 million in the three months ended 2012 and 2011, respectively. Our statements of operations include only our proportionate share of these billings.

NOTE 14 - BUSINESS SEGMENTS

We separate our operating activities into two segments: Oil and Gas Exploration and Production and Gas Marketing. All material inter-company accounts and transactions between segments have been eliminated.

Oil and Gas Exploration and Production. Our Oil and Gas Exploration and Production segment includes all of our natural gas and crude oil properties. The segment represents revenues and expenses from the production and sale of natural gas, NGLs and crude oil. Segment revenue includes natural gas, NGL and crude oil sales, commodity price risk management, net and well operation and pipeline income. Segment income (loss) consists of segment revenue less production cost, exploration expense, impairment of natural gas and crude oil properties, direct general and administrative expense and DD&A expense.

Gas Marketing. Our Gas Marketing segment purchases, aggregates and resells natural gas produced by us and others. Segment income (loss) represents sales from natural gas marketing less costs of natural gas marketing.

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

The following tables present our segment information.

	Three Months Ended March 31,	
	2012	2011

	(in thousands)	
Revenues:		
Oil and Gas Exploration and Production	$88,512	$36,771
Gas Marketing	11,834	15,202
Total	$100,346	$51,973
Segment income (loss) before income taxes:		
Oil and Gas Exploration and Production	$28,627	$(14,044)
Gas Marketing	342	209
Unallocated	(26,830)	(23,690)
Total	$2,139	$(37,525)

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

	March 31, 2012	December 31, 2011
	(in thousands)	
Segment assets:		
Oil and Gas Exploration and Production	$1,509,577	$1,461,130
Gas Marketing	7,171	14,713
Unallocated	48,821	73,913
Assets held for sale	—	148,249
Total	$1,565,569	$1,698,005

NOTE 15 - SUBSEQUENT EVENTS

On May 4, 2012, the semiannual 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, 2011, was completed. Based on the redetermination, our aggregate revolving commitment was increased to $425 million from $400 million. There were no other changes to our corporate bank credit facility as a result of the redetermination.

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

EXECUTIVE SUMMARY

Financial Overview

During the three months ended 2012, we recorded strong increases in Natural gas, NGL and crude oil sales as a direct result of our significant increase in production. Total Natural gas, NGL and crude oil sales increased $16.5 million, or 28.1%, to $75.3 million from $58.8 million for the same period in 2011. Driven by the success of our horizontal Niobrara program, crude oil and NGL production from continuing operations increased 72.9% and 53.8%, respectively, compared to the same period in 2011. These significant increases in production of liquids improved our liquids percentage of total production to 36% from 27% for the comparable three month period in 2011. Our significant increase in liquids more than offset the reduction in natural gas prices. In addition to the net increase in Natural gas, NGL and crude oil sales, our realized gains from derivative transactions increased 151.3% to $10 million during the period compared to $4 million in 2011.

While significantly increasing our total revenues, we were able to control our costs and had only modest increases in production costs, exploration expense and general and administrative costs. On a per unit basis, production cost decreased from $1.76 per Mcfe to $1.47 per Mcfe, general and administrative costs decreased from $1.32 per Mcfe to $1.12 per Mcfe, while exploration expense remained consistent at $0.16 per Mcfe.

Available liquidity as of March 31, 2012 was $308.1 million, which included $7.2 million through our joint venture PDCM, compared to $196.4 million, which included $16.6 million related to PDCM, as of December 31, 2011. Available liquidity is comprised of cash, cash equivalents and funds available under our credit facility. The increased liquidity amount as of March 31, 2012 was primarily attributable to proceeds received from the disposition of our Permian assets in February 2012 and the increased cash flow from operations during the period. Our strong liquidity position has afforded us the opportunity to execute and implement our increased 2012 drilling program and continue to pursue potential acquisitions of oil and natural gas properties in our liquids rich basins.

With our shift to liquids and strong derivatives program, and despite the divestiture of our Permian assets, on May 4, 2012, we completed the redetermination of our corporate bank credit facility's borrowing base, resulting in an increase in our March 31, 2012 available liquidity of $25 million from $400 million to $425 million. See Note 15, Subsequent Events, to the accompanying condensed consolidated financial statements.

Operational Overview

Drilling Activities. During the three months ended 2012, we continued to focus our operations and leasehold acquisitions primarily in the liquids-rich Wattenberg Field of Colorado and the emerging Utica Shale play in Ohio. We drilled six horizontal wells in the Wattenberg Field during the quarter, of which three were completed and turned in line as of March 31, 2012, and participated in three vertical non-operated drilling projects. We also executed 59 refrac/recompletion projects on 31 wells in the Wattenberg area. The shift in the Wattenberg Field from drilling a combination of both vertical and horizontal wells to our current program of drilling primarily horizontal wells has resulted in significantly fewer wells being drilled at a considerably higher expenditure per well and related production and reserves per well. The remaining activity in our Western Operating Region was the completion of our final three Piceance wells from our 2011 capital plan.

PDCM drilled three horizontal Marcellus wells during the quarter, all of which were in-process as of March 31, 2012, before laying down the rig due to the deterioration of natural gas prices in the Appalachian Basin. In addition to PDCM's drilling activity, we completed our first Utica well in our Eastern Operating Region.

Natural Gas and Crude Oil Properties Divestitures. In October 2011, we announced our intent to divest our assets located in the Wolfberry Trend in the Permian Basin in West Texas to focus our efforts on our horizontal drilling programs. During the fourth quarter of 2011, we sold our non-core Permian assets to unrelated third parties for a total of $13.2 million. On December 20, 2011, we executed a purchase and sale agreement with another unrelated third party for the sale of our core Permian assets for a total price of $173.9 million, subject to customary post-closing adjustments. On February 28, 2012, the divestiture closed with total proceeds received of $184.4 million after preliminary closing adjustments, resulting in a pretax gain on sale of $20.3 million. The proceeds from these sales were used to pay down our corporate credit facility and to provide partial funding for our 2012 capital budget, allowing us to accelerate the development of our liquid-rich inventory of projects in the Wattenberg Field and to fund the acquisition of Utica Shale acreage in Ohio, while beginning exploratory activities on this acreage. The results of operations related to our Permian Basin assets are reported as discontinued operations, for all periods presented in the accompanying consolidated statements of operations included in this report.

Current Low Natural Gas Price Environment. The natural gas market continues to be characterized by depressed prices. While we have derivative instruments in place for a majority of our expected natural gas production in 2012 and 2013, sustained low natural gas prices would result in higher realized derivative gains upon settlement but also could have a material adverse effect as a result of lower natural gas sales, a reduction in the estimated quantity of proved reserves and the estimated future net cash flows expected to be generated from these reserves. The above factors could result in a reduction of our credit facility and possible future asset impairments. See Item 3, Quantitative and Qualitative Disclosures About Market Risk.

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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 changes 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, and should not be viewed 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 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,			
	2012	2011	Change	
	(dollars in millions, except per unit data)			
Production (1)				
Natural gas (MMcf)	8,374.1	7,666.2	9.2	%
Crude oil (MBbls)	555.2	321.2	72.9	%
NGLs (MBbls)	228.8	148.8	53.8	%
Natural gas equivalent (MMcfe) (2)	13,077.8	10,485.9	24.7	%
Average MMcfe per day	143.7	116.5	23.3	%
Natural Gas, NGL and Crude Oil Sales				
Natural gas	$17.5	$23.4	(25.2	)%
Crude oil	51.4	28.8	78.5	%
NGLs	6.4	6.6	(2.5	)%
Total natural gas, NGL and crude oil sales	$75.3	$58.8	28.1	%
Realized Gain (Loss) on Derivatives, net (3)				
Natural gas	$12.5	$6.9	81.2	%
Crude oil	(2.6)	(3.1)	(16.1	)%
Total realized gain on derivatives, net	$9.9	$3.8	160.8	%
Average Sales Price (excluding gain/loss on derivatives)				
Natural gas (per Mcf)	$2.09	$3.06	(31.7	)%
Crude oil (per Bbl)	92.61	89.62	3.3	%
NGLs (per Bbl)	28.12	44.32	(36.6	)%
Natural gas equivalent (per Mcfe)	5.76	5.61	2.7	%
Average Sales Price (including gain/loss on derivatives)				
Natural gas (per Mcf)	$3.58	$3.95	(9.4	)%
Crude oil (per Bbl)	87.94	79.98	10.0	%
NGLs (per Bbl)	28.12	44.32	(36.6	)%
Natural gas equivalent (per Mcfe)	6.52	5.97	9.2	%
Average Lifting Cost (per Mcfe) (4)	$0.88	$1.06	(16.9	)%
Natural Gas Marketing (5)	$0.3	$0.2	50.0	%
Other Costs and Expenses				
Exploration expense	$2.1	$1.7	23.6	%
General and administrative expense	14.7	13.9	6.0	%
Depreciation, depletion and amortization	39.8	31.0	28.5	%

Interest Expense	$10.4	$9.1	15.3 %

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 does not include realized derivative gains and losses related to natural gas marketing.

(4) Represents lease operating expenses, exclusive of production taxes, 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

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natural gas marketing activities.

Natural Gas, NGL and Crude Oil Sales

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

	Three Months Ended March 31,			
	2012	2011	Percentage Change	
Production				
Natural gas (MMcf)				
Western	6,880.2	6,787.5	1.4	%
Eastern	1,485.5	866.9	71.4	%
Other	8.4	11.8	(28.8	)%
Total	8,374.1	7,666.2	9.2	%
Crude oil (MBbls)				
Western	552.8	320.0	72.8	%
Eastern	2.4	1.1	118.2	%
Other	—	0.1	(100.0	)%
Total	555.2	321.2	72.9	%
NGLs (MBbls)				
Western	227.2	147.5	54.0	%
Other	1.6	1.3	23.1	%
Total	228.8	148.8	53.8	%
Natural gas equivalent (MMcfe)				
Western	11,559.0	9,592.0	20.5	%
Eastern	1,499.8	873.7	71.7	%
Other	19.0	20.2	(5.9	)%
Total	13,077.8	10,485.9	24.7	%

Amounts may not recalculate due to rounding.

Average Sales Price (excluding gain/loss on derivatives)	Three Months Ended March 31, 2012	2011	Percentage Change
Natural gas (per Mcf) (1)			
Western	$2.01	$2.92	(31.2)%
Eastern	2.44	4.11	(40.6)%
Other	2.79	2.56	9.0 %
Weighted average price	2.09	3.06	(31.7)%
Crude oil (per Bbl)			
Western	92.60	89.67	3.3 %
Eastern	98.95	76.00	30.2 %
Other	—	85.61	(100.0)%
Weighted average price	92.61	89.62	3.3 %
NGLs (per Bbl)			
Western	28.01	44.10	(36.5)%
Other	43.55	69.50	(37.3)%
Weighted average price	28.12	44.32	(36.6)%
Natural gas equivalent (per Mcfe)			
Western	6.17	5.74	7.5 %
Eastern	2.58	4.17	(38.1)%
Other	8.59	6.39	34.4 %
Weighted average price	5.76	5.61	2.7 %

Amounts may not recalculate due to rounding.

(1) Our average sales price for natural gas is based on the "net-back" method of accounting for transportation, gathering and processing arrangements with natural gas purchasers. See our revenue recognition policy described in Note 2, Summary of Significant Accounting Policies, to the consolidated financial statements in our 2011 Form 10-K.

For the three months ended 2012, natural gas, NGL and crude oil sales revenue increased compared to the three months ended 2011 due to the following (in millions):

Increase in crude oil production	$21.0
Increase in natural gas production	2.2
Increase in average crude oil price	1.6
Decrease in average natural gas price	(8.1)
Decrease in NGL sales	(0.2)
Total increase in natural gas, NGL and crude oil sales revenue	$16.5

Natural Gas, NGL and Crude Oil Pricing. Our results of operations depend upon many factors, particularly the price of natural gas, NGLs and crude oil and our ability to market our production effectively. Natural gas, crude oil and NGL prices are among the most volatile of all commodity prices. These price variations have a material impact on our financial results and capital expenditures. We have experienced a decline in the price of NGLs, mainly at Conway hub in Kansas where our Wattenberg production is priced, primarily due to increased ethane volumes and the limited market for ethane. Natural gas 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. 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, 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 national and international politics.

The price we receive for our natural gas produced in our Western Operating 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 western area pipelines, has 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 between NYMEX and CIG averaged $0.12 and $0.28 for the three months ended 2012 and 2011, respectively.

The price we receive for our natural gas is impacted by our transportation, gathering and processing agreements. We currently use the "net-back" method of accounting for these arrangements related to our natural gas sales. We sell natural gas at the wellhead and collect a price and recognize revenues based on the wellhead sales price since transportation costs downstream of the wellhead are incurred by the purchaser and reflected in the wellhead price. The net-back method results in the recognition of a sales price that is below the indices for which the production is based.

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,	
	2012	2011
	(in millions)	
Lease operating expenses	$11.5	$11.1
Production taxes	5.0	4.1
Cost of well operations, overhead and other production expenses	2.7	3.3
Total production costs	$19.2	$18.5

Lease operating expenses. The increase in lease operating expenses during the three months ended 2012 compared to 2011 was primarily related to the 24.7% increase in production offset in part by a decrease of $1.1 million in well workover expense, $1.6 million in environmental expenses, and $0.7 million in saltwater disposal and water hauling expenses following the completion of our saltwater disposal facility in the Piceance Basin. On a per Mcfe basis, lifting costs decreased 16.9% to $0.88 for the three months ended 2012, compared to $1.06 in 2011. The decrease in the per Mcfe cost was primarily due to the increase in production during the three months ended 2012, which resulted in the non-production based portion of our lease operating expenses being spread across an increased number of units.

Production taxes. Production taxes are directly related to natural gas, NGL and crude oil sales. The $0.9 million increase in production taxes for the three months ended 2012 compared to the three months ended 2011, or a 22% increase, was primarily related to the 28.1% 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. We sell all of our physical natural gas and crude oil at similar prices to the indices inherent in our derivative instruments. As a result, for the volumes underlying our derivative positions, 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, 2012.

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

	Three Months Ended March 31,	
	2012	2011
	(in millions)	
Commodity price risk management gain (losses), net:		
Realized gains (losses):		
Natural gas	$12.5	$6.9
Crude oil	(2.6)	(3.1)
Total realized gains, net	9.9	3.8
Unrealized gains (losses):		
Reclassification of realized gains included in prior periods unrealized	(8.6)	(3.3)
Unrealized gains (losses) for the period	10.2	(24.4)
Total unrealized gains (losses), net	1.6	(27.7)
Total commodity price risk management gain (losses), net	$11.5	$(23.9)

Realized gains recognized in the three months ended 2012 are primarily the result of lower natural gas spot prices at settlement compared to the respective strike price of our natural gas derivative positions. For the three months ended 2012, realized gains on natural gas, exclusive of basis swaps, were $17.1 million. These gains were reflective of a weighted average strike price of $6.01 compared to a weighted average settlement price of $2.72. These gains were offset in part by realized losses of $4.6 million on our basis swap positions as the negative basis differential between NYMEX and CIG was a weighted average of $0.11 compared to a weighted average strike price of $1.83.

The realized gains on natural gas derivative positions for the three months ended 2012 were offset in part by realized losses on our crude oil positions as a result of higher spot prices at settlement compared to the respective strike price on our derivative positions. For the three months ended 2012, the realized losses were reflective of a weighted average settlement price of $103.30 compared to a weighted average strike price of $91.41.

Unrealized gains for the three months ended 2012 were primarily related to the downward shift in the natural gas forward curve and its impact on the fair value of our open positions, offset in part by the upward shift in the crude oil forward curve and the narrowing of the CIG basis forward curve. For the period ended 2012, unrealized gains on our natural gas positions were $22.4 million, offset slightly by unrealized losses on our crude oil positions and CIG basis swaps of $12.1 million and $0.1 million, respectively.

During the three months ended 2011, we recorded net realized gains of $3.8 million as a result of natural gas spot prices being lower at settlement compared to the respective strike price, offset in part by oil spot prices being higher than the respective strike prices. Realized gains on natural gas, exclusive of basis swaps, were $9 million, 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 as described above.

Unrealized losses during the three months ended 2011 were 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, along with the shift upward in the natural gas curve and the narrowing of the basis curve resulting in a total unrealized loss of $3 million for the period.

Natural Gas Marketing

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

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

	Three Months Ended March 31,	
	2012	2011
	(in millions)	
Sales from natural gas marketing		
Natural gas sales revenue	$10.9	$15.1
Realized derivative gain	0.8	1.1
Unrealized derivative gain (loss)	0.1	(1.0)
Total sales from natural gas marketing	11.8	15.2
Cost of natural gas marketing		
Cost of natural gas purchases	10.3	14.6
Realized derivative loss	0.8	1.0
Unrealized derivative loss (gain)	0.1	(0.9)
Other	0.3	0.3
Total cost of natural gas marketing	11.5	15.0
Natural gas marketing contribution margin	$0.3	$0.2

Natural gas sales revenue and cost of natural gas purchases significantly decreased in the period compared to the comparable prior year period primarily due to lower natural gas prices, with a 37.5% decrease in the average natural gas sales price and a 39.6% decrease in the average natural gas purchase price. The effect of the lower natural gas prices were offset in part by a 16.4% increase in volume.
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 natural 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 2011 Form 10-K for a discussion of how each derivative type impacts our cash flows.

General and Administrative Expense

General and administrative expense increased $0.8 million to $14.7 million for the three months ended 2012 compared to $13.9 million for the three months ended 2011. The increase was primarily due to increased payroll and employee benefits of $1.9 million and increased transaction and legal costs of $0.7 million, partially offset by a $1.6 million charge related to the settlement agreement reached with regard to our West Virginia royalty lawsuit in the first quarter of 2011.

Depreciation, Depletion and Amortization

Natural gas and crude oil properties. DD&A expense related to natural gas and crude oil properties increased $8.7 million, or 29.7%, to $38 million for the three months ended 2012 compared to $29.3 million for the three months ended 2011. The 24.7% increase in our production contributed $7.2 million to the increase, while the higher weighted average DD&A rate contributed $1.5 million to the increase.

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

Three Months Ended March 31,

Operating Region/Area	2012	2011
	(per Mcfe)	
Western		
Wattenberg Field	$3.44	$3.26
Piceance Basin	2.80	2.54
Weighted average	3.05	2.82
Eastern	1.77	2.52
Total weighted average	2.90	2.79

Non-natural gas and crude oil properties. Depreciation expense for non-natural gas and crude oil properties was $1.8 million for the three months ended 2012 compared to $1.7 million for the three months ended 2011.

Non-Operating Income/Expense

Interest Expense. The $1.4 million increase in interest expense for the three months ended 2012 compared to the three months ended 2011 was primarily due to significantly higher average outstanding balances on our credit facility during the 2012 period. The average outstanding balance in 2012 was $166.3 million compared to no outstanding balance in 2011 as a result of our capital market transactions in November of 2010.

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 quarter-over-quarter effective tax rate. Note that the rate for the three months ended 2012 of 35.5% is a provision on income versus the 2011 38.1% benefit on loss. We have accepted an offer for continued participation in the IRS CAP program for our 2011 and 2012 tax years.

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 Permian and North Dakota assets.

In February 2011, we completed the sale of our North Dakota assets to an unrelated third party for a pretax gain of $3.9 million. In October 2011, we developed a plan to divest our Permian Basin asset group. The plan included 100% of our Permian Basin assets, consisting of producing wells and undeveloped leaseholds. In December 2011, we executed a purchase and sale agreement with COG Operating LLC (“COG”), a wholly owned subsidiary of Concho Resources Inc., an unrelated third party, for the sale of our Permian Basin assets and closed the transaction in February 2012. Proceeds from the sale were $184.4 million subject to post closing adjustments, resulting in a pretax gain on sale of $20.3 million.

The table below presents production data related to the assets divested.

	Three Months Ended March 31,	
Discontinued Operations	2012	2011
Production		
Natural gas (MMcf)	40.3	89.8
Crude oil (MBbls)	39.2	54.0
NGLs (per Bbl)	13.0	18.1
Natural gas equivalent (MMcfe)	353.1	522.7

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

Net income attributable to shareholders for the three months ended 2012 was $15.8 million compared to net loss of $19.9 million for the three months ended 2011. Adjusted net income attributable to shareholders, a non-U.S. GAAP financial measure, for the three months ended 2012 was $14.9 million compared to an adjusted net loss of $2.7 million for the three months ended 2011. The quarter-over-quarter changes in net income (loss) attributable to shareholders are discussed above, with the most significant changes being related to the increase in natural gas, NGL and crude oil sales, commodity price risk management activities and the results of our discontinued operations. These same reasons 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.

Financial Condition, Liquidity and Capital Resources

Our primary sources of liquidity have been cash flows provided by operating activities and our corporate bank credit facility. As market conditions have permitted, we have utilized the debt and equity markets and engaged in asset monetization of non-core assets as additional sources of liquidity. For the three months ended March 31, 2012, our primary sources of liquidity were the sale of our Permian assets for $184.4 million and net cash flow provided by operating activities of $44.3 million.

Our primary source of cash flows provided by operations is the sale of natural gas, NGLs and crude oil. Fluctuations in our operating cash flow 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 use of derivatives, which has also historically been a source of cash. 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 (proved developed producing, proved developed not producing and proved undeveloped). 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 proved developed producing properties. 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 changes in our cash and cash equivalents due to our practice of utilizing excess cash to reduce the outstanding borrowings under our corporate credit facility. At March 31, 2012, we had a working capital deficit of $5.3 million compared to a deficit of $22 million at December 31, 2011. The decrease in our working capital deficit was primarily related to the increase in the fair value of our derivatives and the decrease in accounts payable due to timing of our cash payments.

We ended March 2012 with cash and cash equivalents of $1.7 million and availability under our credit facility of $306.4 million, for a total liquidity position of $308.1 million compared to $196.4 million at December 31, 2011. The increase in liquidity of $111.7 million, or 56.9%, was primarily due to $184.4 million received from the divestiture of our Permian assets in February 2012 and cash flows provided by operating activities of $44.3 million offset in part by capital expenditures of $107 million during the three months ended 2012. With our current liquidity position and expected cash flows from operations, we believe that we have sufficient capital for operations. We continue to execute our strategy of pursuing strategic and complementary acquisitions of developed and undeveloped properties in the Niobrara formation of our Western Operating Region and the emerging Utica Shale play of our Eastern Operating Region. Such acquisitions, an acceleration of development activities or other changes to our business plans could increase our need for capital.

Capital Expenditures

2012 Capital Budget. We establish a capital budget 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 budget during the year as a result of acquisitions and dispositions of assets, drilling results, commodity prices, changes in our borrowing capacity and/or significant changes in cash flows. In December 2011, our Board of Directors approved our 2012 capital budget of $284 million, excluding our share of PDCM's capital budget. Based on our current budget, we expect to allocate $184 million for developmental drilling, including recompletions and refractures, of which approximately 97% is expected to be invested in the Wattenberg field. The remaining $100 million is allocated to acquisitions of properties and leased acreage, exploration and other capital needs. During the three months ended 2012, we drilled six wells and completed 59 refractures/recompletions in our Wattenberg Field on 31 wells. PDCM's capital budget for 2012 includes funding for the drilling of four gross horizontal wells and the completion of seven wells. During the three months ended 2012, PDCM drilled three horizontal Marcellus wells. PDCM's 2012 capital budget is currently set at $60 million, of which $30 million represents our share, and is expected to be funded by PDCM's operating activities and its credit facility. We believe, based on the current commodity price environment, with our extensive derivative program and our estimated 2012 production of approximately 53 Bcfe, our cash flows provided by operating activities and the sale of our Permian assets will fund our current 2012 capital budget while maintaining a solid liquidity position.

Because natural gas and crude oil production from a well 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 from operations 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 natural gas and crude oil 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 2012 and beyond and could have a material negative impact on our operations in the future.

Financing Activities

In recent periods, we have been able to access borrowings under our corporate credit facility and to obtain financing from the capital markets. However, we cannot assure this will continue to be the case in the future. We continue to monitor market events and circumstances and their potential impacts on each of the lenders that comprise our bank credit facility. Our $425 million 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. See Note 15, Subsequent Events, to our accompanying financial statements. 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. Our next scheduled redetermination is in November 2012. While we have continued to add producing reserves through our drilling operations since our last redetermination, we believe a significant decrease in commodity prices could have a negative impact on our future borrowing base redeterminations.

On January 23, 2012, we filed with the SEC an automatic shelf registration statement on Form S-3. Effective upon filing, the shelf provides for the potential sale of an unspecified amount 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 and to have the flexibility to raise such funds in one or more offerings should we perceive the market conditions to be favorable.

We are subject to quarterly financial debt covenants on our bank credit facility. Currently, our key credit facility debt covenants require that we maintain: 1) total debt of less than 4.0 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 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, 2012, and expect to remain in compliance throughout the next year.

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, 2012, and expect to remain in compliance throughout the next year.

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

Cash Flows

Operating Activities. Our net cash flow 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 increased for the three months ended 2012 compared to the three months ended 2011. The increase was primarily due to the $16.5 million increase in natural gas, NGL and crude oil sales revenue and the $6 million increase in net realized derivative gains. See Results of Operations above for an additional discussion of the key drivers of cash flows provided by operating activities.

Adjusted cash flows from operations and adjusted EBITDA increased for the three months ended 2012 compared to the three months ended 2011. These increases were primarily due to the same factors mentioned above for changes in cash provided by operating activities without regard to timing of cash payments and receipts of our assets and liabilities. The increase in adjusted EBITDA was also due to the gain recognized on the sale of our Permian assets. 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 provided by investing activities was primarily related to the $184.4 million received from the divestiture of our Permian assets in February 2012, offset in part by cash used for exploration and development of natural gas and crude oil properties. Additionally, the proceeds were also offset by a $10 million expenditure related to a possible transaction to acquire leaseholds and crude oil and natural gas properties. In certain circumstances, if we do not proceed with the transaction, we may not recover such deposit, in which case it will be expensed in our Statement of Operations in the second quarter of 2012. Our drilling program currently consists of one rig operating in the oil and liquids-rich horizontal Niobrara play in our Wattenberg Field and will soon include an additional rig in the emerging Utica shale play to support our exploratory efforts there.

Financing Activities. Cash flows provided by financing activities for the three months ended 2012 decreased significantly compared to the three months ended 2011. The decrease is primarily related to our utilization of proceeds provided from the divestiture of our Permian assets in February 2012 to pay down our corporate credit facility and partially fund our capital expenditures. It was therefore not necessary to draw on our corporate bank credit facility.

Drilling Activity

The following table presents our net 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.

	Net Drilling Activity Three Months Ended March 31,			
	2012		2011	
Operating Region/Area	Productive	In-Process (1)	Productive	In-Process
Development Wells				
Western				
Wattenberg Field	2.3	3.7	9.3	18.6
Piceance Basin	—	—	—	6.0
Total Western	2.3	3.7	9.3	24.6
Eastern	—	1.5	—	—
Total development wells	2.3	5.2	9.3	24.6
Exploratory Wells				
Western				
Other	—	—	—	1.0
Total exploratory wells	—	—	—	1.0
Total drilling activity	2.3	5.2	9.3	25.6

(1) As of March 31, 2012, a total of 10.5 net wells, including the 5.2 net wells drilled during the three months ended 2012 and still in-process as of March 31, were waiting to be completed and/or for pipeline connection.

Off-Balance Sheet Arrangements

From time to time, we enter into arrangements and transactions that can give rise to off-balance sheet obligations. These arrangements are identified under the caption Contractual Obligations and Contingent Commitments in our 2011 Annual Report on Form 10-K. There have been no material changes to our contractual obligations from December 31, 2011. See Note 9 for a discussion of our firm transportation agreements.

Commitments and Contingencies

See Note 9, Commitments and Contingencies, 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.

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 2011 Form 10-K.

Reconciliation of Non-U.S. GAAP Financial Measures

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

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

Adjusted EBITDA. We define adjusted EBITDA as net income (loss) plus unrealized derivative loss, interest expense, net of interest income, income taxes, impairment of natural gas and crude oil properties and depreciation, depletion and amortization for the period minus unrealized derivative gain. 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 our non-U.S. GAAP financial measures to its nearest U.S. GAAP measure.

	Three Months Ended March 31,			
	2012		2011	
	(in millions)			
Adjusted cash flows from operations:				
Adjusted cash flows from operations	$49.5		$26.1	
Changes in assets and liabilities	(5.2	)	(10.6	)
Net cash provided by operating activities	$44.3		$15.5	
Adjusted net income (loss) attributable to shareholders:				
Adjusted net income (loss) attributable to shareholders	$14.9		$(2.7	)
Unrealized gain on derivatives, net	1.5		(27.7	)
Tax effect of above adjustments	(0.6	)	10.5	
Net income (loss) attributable to shareholders	$15.8		$(19.9	)
Adjusted EBITDA:				
Adjusted EBITDA	$74.7		$37.4	
Unrealized gain (loss) on derivatives, net	1.5		(27.7	)
Interest expense, net	(10.4	)	(9.0	)
Income tax benefit (expense)	(9.5	)	12.3	
Impairment of natural gas and crude oil properties	(0.7	)	(0.5	)
Depreciation, depletion and amortization	(39.8	)	(32.4	)
Net income attributable to shareholders	$15.8		$(19.9	)

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

Market-Sensitive Instruments and Risk Management

We are exposed to market risks associated with interest rates, commodity prices and credit exposure. We have 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 interest bearing cash, cash equivalents and restricted cash accounts and the interest we pay on borrowings under our bank credit facilities. All of our senior notes 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, 2012, 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, which excludes restricted cash, as of March 31, 2012, was $4.5 million and represents our aggregate bank balances, including checks issued and outstanding. Based on a sensitivity analysis of our interest bearing deposits as of March 31, 2012, we estimate that if market interest rates were to increase or decrease by 1%, the impact on our 2012 interest income would be immaterial.

As of March 31, 2012, excluding the $18.7 million irrevocable standby letters of credit, we had outstanding borrowings on our corporate bank credit facility of $82 million and, representing our proportionate share, $32.8 million on PDCM's bank credit facility. We estimate that if market interest rates were to increase or decrease by 1%, interest expense for the three months ended 2012 would change by approximately $0.3 million for the three months ended 2012.

Potential for Future Asset Impairments

The domestic natural gas market remains weak. A further decrease in forward natural gas prices during 2012 could result in significant impairment charges. Our Piceance Basin properties have significant natural gas reserves, representing 47% of our total proved natural gas reserves and 32% of our total proved reserves at December 31, 2011, and are sensitive to declines in natural gas prices. These assets, which had a net book value of approximately $311.6 million at March 31, 2012, are at risk of impairment if future natural gas prices for production in this area experience further long-term decline. The cash flow model we use to assess properties for impairment includes numerous assumptions, such as management's estimates of future oil and gas production and commodity prices, market outlook on forward commodity prices and operating and development costs. All inputs to the cash flow model must be evaluated at each date that the estimate of future cash flows for each producing basin is calculated. However, a significant decrease in long-term forward natural gas prices alone could result in a significant impairment for our properties that are sensitive to declines in natural gas prices.

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.

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 periods, offsetting the physical derivative.

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The following table presents our derivative positions (excluding the derivative positions designated to our affiliated partnerships and our Gas Marketing Segment) related to natural gas and crude oil sales in effect as of March 31, 2012.

	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 as of March 31, 2012 (2)(in millions)
Natural Gas										
NYMEX										
2012	—	$ —	3,629.7	$6.00	$8.27	14,374.5	$5.08	7,692.6	$(1.81)	$37.7
2013	—	—	4,438.0	6.10	8.60	18,120.9	4.93	9,383.3	(1.81)	25.7
2014	—	—	—	—	—	13,090.0	4.04	—	—	1.0
2015						7,200.0	3.84			(2.7)
2016						7,200.0	3.84			(4.4)
CIG										
2012	—	—	—	—	—	565.0	4.11	—	—	1.0
2013	—	—	235.0	4.00	5.45	—	—	—	—	0.2
2014	—	—	1,115.0	4.50	5.67	—	—	—	—	1.1
2015	—	—	1,040.0	4.50	5.67	—	—	—	—	0.7
PEPL										
2012	—	—	—	—	—	998.2	6.18	—	—	3.8
2013	—	—	—	—	—	990.4	6.18	—	—	2.9
Total Natural Gas	—		10,457.7			62,539		17,075.9		67.0
Crude Oil										
NYMEX										
2012	18.0	65.38	496.6	81.83	106.62	597.4	92.70	—	—	(9.2)
2013	—	—	617.6	78.89	104.27	1,100.9	96.77	—	—	(11.4)
2014	—	—	268	89.05	107.04	—	—	—	—	(0.2)
2015	—	—	36	90.00	106.15	—	—	—	—	0.1
Total Crude Oil	18.0		1,418.2			1,698.3		—		(20.7)
Total Natural Gas and Crude Oil										$46.3

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

(2) Approximately 27.7% of the fair value of our derivative assets and 14.5% 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, 2012	Year Ended December 31, 2011
Average Index Closing Price		
Natural Gas (per MMBtu)		
CIG	$2.62	$3.79
NYMEX	2.74	4.04
Crude Oil (per Bbl)		
NYMEX	100.51	94.01
Average Sales Price Realized		
Excluding realized derivative gains/(losses)		
Natural Gas (per Mcf)	$2.09	$3.27
Crude Oil (per Bbl)	92.61	87.63
Including realized derivative gains/(losses)		
Natural Gas (per Mcf)	3.58	4.23
Crude Oil (per Bbl)	87.94	80.69

Based on a sensitivity analysis as of March 31, 2012, we estimated that a 10% increase in both natural gas and crude oil prices, inclusive of basis, over the entire period for which we have derivatives in place, including those designated to our affiliated partnerships, would have resulted in a decrease in the fair value of our derivative positions of $51.9 million; a 10% decrease in prices would have resulted in an increase in fair value of $50.8 million. Excluding the derivatives designated to our affiliated partnerships, the same 10% increase or decrease in natural gas and crude oil prices would have resulted in a decrease in fair value of $50.9 million and an increase in fair value of $49.8 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, 2012.

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 Oil and Gas Exploration and Production 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 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 Oil and Gas Exploration and Production or Gas Marketing segments.

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 financial 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. See Note 4, Derivative Financial Instruments, to our condensed consolidated financial statements included in this report.

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 assure performance by a financial institution.

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Disclosure of Limitations

Because the information above included only those exposures that existed at March 31, 2012, 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.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of March 31, 2012, 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, 2012.

Changes in Internal Control over Financial Reporting

During the three months ended 2012, 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 2011 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 2011 Form 10-K except for the following:

Our ability to produce natural gas and crude oil could be impaired if we are unable to acquire adequate supplies of water for our drilling and completion operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules.

Our operations could be adversely impacted if we are unable to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations. Currently, the quantity of water required in certain completion operations, such as hydraulic fracturing, and changing regulations on usage may lead to water constraints and supply concerns (particularly in some parts of the country). As a result, future availability of water from certain sources used in the past may be limited. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and natural gas. The federal Clean Water Act ("CWA") and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas waste, into navigable waters. Permits or other approvals must be obtained to discharge pollutants to regulated waters and to conduct construction activities in such waters and wetlands. Uncertainty regarding regulatory jurisdiction over wetlands and other regulated waters has, and will continue to, complicate and increase the cost of obtaining such permits or other approvals. The CWA and analogous state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. Many state discharge regulations, and the Federal National Pollutant Discharge Elimination System general permits issued by the Environmental Protection Agency, or EPA, prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into coastal waters. While generally exempt under federal programs, many state agencies have also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. On October 20, 2011, the EPA announced its intention to develop federal pretreatment standards for wastewater discharges associated with hydraulic fracturing activities. If adopted, the pretreatment rules will require coalbed methane and shale gas operations to pretreat wastewater before transferring it to treatment facilities. Proposed rules are expected in 2013 for coalbed methane production and in 2014 for shale gas production. Finally, there has been recent nationwide concern over earthquakes associated with Class II underground injection control wells, a predominant storage method for crude oil and gas wastewater. It is likely that new rules and regulations will be developed to address these concerns, possibly eliminating access to Class II wells in certain locations, and increasing the cost of disposal in others. While we cannot predict the impact that these changes may have on our business at this time, they may be material to our business, financial condition, and operations. Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells will increase our operating costs and may cause delays, interruptions or termination of our operations, the extent of which cannot be predicted. In addition, our inability to meet our water supply needs to conduct our completion operations may impact our business, and any such future laws and regulations could negatively affect our financial condition and results of operations.

Federal, state and potentially local legislative and regulatory initiatives, and litigation relating to hydraulic fracturing could result in increased costs and additional drilling and operating restrictions or delays in the production of natural gas and crude oil, including from the development of shale plays. A decline in the drilling of new wells and related servicing activities caused by these initiatives and litigation could adversely affect our financial condition, results of operations and cash flows.

Most of our drilling uses hydraulic fracturing. Hydraulic fracturing is an important and commonly used process in the completion of unconventional natural gas and crude oil wells in shale, coalbed and tight sand formations. Proposals have been introduced in the U.S. Congress to regulate hydraulic fracturing operations and related injection of fracturing fluids and propping agents used by the oil and natural gas industry in fracturing fluids under the Safe Water Drinking Act, or SDWA, and to require the disclosure of chemicals used in the hydraulic fracturing process under the SDWA, Emergency Planning and Community Right-to-Know Act (“EPCRA”), or other laws. Sponsors of these bills, which are currently being considered in the legislative process, including in the House Energy and Commerce Committee and the Senate Environmental and Public Works Committee, have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies and otherwise cause adverse environmental impacts. The Chairman of the House Energy and Commerce Committee has initiated an investigation of the potential impacts of hydraulic fracturing, which has involved seeking information about fracturing activities and chemicals from certain companies in the oil and natural gas sector. The EPA has recently focused on citizen concerns about the risk of water contamination and public health problems from drilling and hydraulic fracturing activities, and conducted public meetings around the country on this issue which have been well publicized and well attended. The EPA continues to highlight environmental justice issues related to these citizen concerns. In March 2011, the EPA announced its intention to conduct a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. The initial results are expected in the fall of 2012, with final results expected in 2014. The EPA has also begun a Toxic Substances Control Act rulemaking which will collect expansive information on the chemicals used in hydraulic fracturing fluid, as well as other health-related data, from chemical manufacturers and processors. EPA also has finalized major new Clean Air Act (“CAA”) standards (NSPS and NESHAPs) applicable to hydraulically fractured natural gas wells. The rule will require, among other things, use of reduced emission completions, or green completions, to reduce volatile organic compound emissions from well completions. While most key provisions in the new CAA rule are not effective until 2015, the rules are substantial and may increase future costs of our operations. Certain other federal agencies are analyzing, or have been requested to review, environmental issues associated with hydraulic fracturing. The U.S. Department of the Interior, through the Bureau of Land Management, has drafted a proposal that, if approved, would require, among other things, disclosure of chemicals used in fracturing operations on public land.

In addition, certain states in which we operate, including Colorado, Pennsylvania, Ohio, and West Virginia, have adopted, and other states are considering adopting, laws and regulations that could impose, among other requirements, stringent permitting, disclosure, wastewater disposal, well construction and well location requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. Lawsuits have been filed against unrelated third parties in Pennsylvania, New York, Arkansas and several other states alleging contamination of drinking water by hydraulic fracturing. Lawsuits have also been filed in several states challenging state preemption over the regulation of the crude oil and gas industry and seeking to impart greater authority to local municipalities to limit or prohibit crude oil and gas activity, and in some states have been successful (including in Pennsylvania). Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to natural gas and crude oil production activities using hydraulic fracturing techniques. Additional legislation, regulation, or litigation could also lead to operational delays or lead us to incur increased operating costs in the production of natural gas and crude oil, including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing or other drilling activities. If these legislative, regulatory, and litigation initiatives cause a material decrease in the drilling of new wells and in related servicing activities, our profitability could be materially impacted.

Continued depressed natural gas prices could result in significant impairment charges and significant downward revisions of proved natural gas reserves for the Company's Piceance and Northeastern Colorado (NECO) dry-gas assets.

The domestic natural gas market remains weak and natural gas prices have rapidly declined in 2012. A further decrease in forward natural gas prices during 2012 could result in significant impairment charges. Our wells in the Piceance Basin predominantly target natural gas, with the area's volume of natural gas reserves representing 47% of our proved natural gas reserves and 32% of our total proved reserves at December 31, 2011. These assets, which had a net book value of approximately $311.6 million at March 31, 2012, are at risk of impairment if future natural gas prices for production in this area experience further long-term decline. The cash flow model we use to assess properties for impairment includes numerous assumptions, such as management's estimates of future oil and gas production and commodity prices, market outlook on forward commodity prices and operating and development costs. All inputs to the cash flow model must be evaluated at each date that the estimate of future cash flows for each producing basin is calculated. However, a significant decrease in long-term forward natural gas prices alone could result in a significant impairment for our properties that are sensitive to declines in natural gas prices.

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In addition, pursuant to SEC disclosure rules, continued depressed natural gas prices could result in a significant downward revision to the Company's natural gas proven reserves in our Piceance and NECO gas fields. Our Piceance field contains significant proved undeveloped natural gas reserves that may not meet SEC economic guidelines to be categorized as proved reserves in the future given both the current low gas prices and the significant capital costs required to drill these wells.

Environmental and overall public scrutiny are increasingly focused on the oil and gas industry. The current trend is to increase regulation of our operations and the industry. We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Our exploration, development, production and marketing operations are regulated extensively at the federal, state, and local levels. Environmental and other governmental laws and regulations have increased our costs to plan, design, drill, install, operate and abandon natural gas and crude oil wells. Under these laws and regulations, we could also be liable for personal injuries, property damage and natural resource or other damages. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years-particularly with respect to hydraulic fracturing- and environmental organizations have opposed, with some success, certain drilling projects.

In addition, our activities are subject to the regulation of conservation practices and protection of correlative rights by state government. These regulations affect our operations, increase our costs of exploration and production and limit the quantity of natural gas and crude oil that we can produce and market. A major risk inherent in our drilling plans is the need to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to explore on or develop our properties. Additionally, the natural gas and crude oil regulatory environment could change in ways that might substantially increase our financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability. Furthermore, these additional costs may put us at a competitive disadvantage compared to larger companies in the industry which can spread such additional costs over a greater number of wells and larger operating staff. Regulation of our activities by counties, municipalities and other local governmental bodies may have similar adverse effects. Some local governmental bodies have adopted or are considering regulations regarding, among others things, land use, requiring the posting of bonds to secure restoration obligations and limiting hydraulic fracturing and other drilling activities, and these regulations may limit, delay or prohibit exploration and development activities or make those activities more expensive. For instance, Garfield County, Colorado has enacted local land and road use restrictions that could affect our Piceance Basin operations and could require us to post bonds to secure any restoration obligations. Further, a task force convened by the Governor of Colorado recently issued recommendations concerning the coordination of the regulation of oil and gas development between the state and various local bodies. While the impact of the recommendations has not been determined, they may lead to increased oversight of oil and gas activities by local governmental bodies.

The BP crude oil spill in the Gulf of Mexico and heightened industry scrutiny has resulted and may result in new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. Although we have no operations in the Gulf of Mexico, this incident could result in regulatory initiatives in other areas as well that could limit our ability to drill wells and increase our costs of exploration and production. The EPA has recently focused on citizen concerns about the risk of water contamination and public health problems from drilling and hydraulic fracturing activities, and conducted public meetings around the country on this issue which have been well publicized and well attended. This renewed focus could lead to additional federal, state and local laws and regulations affecting our drilling, fracturing and operations. Additional laws, regulations or other changes could significantly reduce our future growth, increase our costs of operations, and reduce our cash flow, in addition to undermining the demand for the natural gas and crude oil we produce.

Other potential laws and regulations affecting us include new or increased severance taxes proposed in several states, including Pennsylvania. This could adversely affect the existing operations in these states and the economic viability of future drilling. Additional laws, regulations or other changes could significantly reduce our future growth, increase our costs of operations and reduce our cash flow, in addition to undermining the demand for the natural gas and crude oil we produce.

Risks Related to the Domestic and Global Economic Environment

The current slow economic growth both domestically and globally may not improve or there may be a reoccurrence of the disruptions during the recent recession in the global financial markets and the related economic environment may further decrease the demand for natural gas and crude oil and the prices of natural gas and crude oil, negatively impacting our future drilling and production, and adversely affecting our financial condition and profitability.

The global financial market disruptions during the recent recession and the related economic environment initially resulted in a decrease, and more recently in 2011, limited growth in the demand for natural gas and crude oil and have maintained pressure on natural gas prices. For example, during 2011, the price for natural gas decreased another 8% from 2010 rates, which were over 60% below the 2008 peak. Natural gas prices have continued to decline in 2012, reaching a low Henry Hub spot price of $2.00 per MMbtu in the first quarter of the year. Crude oil prices rebounded in 2011, increasing 20% over 2010 rates, but were still 28% below the 2008 peak. While crude oil prices have remained relatively strong, the continued growth in production of natural gas has increased supply and resulted in record gas storage inventories. As a result natural gas prices continue to face downward pressure. There is no certainty how long this low price environment would continue. We operate in a highly competitive industry, and certain competitors may have lower operating costs in such an environment. In particular, consider the risks related to (1) the deterioration of demand for natural gas and crude oil products and the related negative impact on natural gas and crude

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oil pricing, and (2) the deterioration of the financial markets and the related challenges, constraints or inability to raise necessary capital or maintain sufficient liquidity to access and provide the capital necessary to fund our operations. Further reductions in natural gas and crude oil prices could result in some of our assets becoming uneconomic to exploit, which would reduce our economically viable reserve profile. Counterparty failure risk would increase for both the banks which provide us capital and are parties to our natural gas and crude oil derivative holdings and for purchasers of our natural gas and crude oil. A prolonged and material negative economic environment could lead to the curtailment of capital expenditures and therefore a reduction in our drilling program, which would result in reduced production, reserves, cash flow generation and financial results.

Credit and funding challenges of French banks which are participants in our revolving credit facility and counterparties to some of our natural gas and crude oil derivative holdings could have a material adverse effect on our operations and financial condition.

We have two French banks, Credit Agricole Corporate and Investment Bank ("CA"), and Natixis (collectively "the French Banks") that participate in our revolving credit facility and are counterparties to some of our natural gas and crude oil derivative hedges. The recent global economic turmoil, particularly in Europe, has led to negative credit actions and created an increased cost for the French Banks to provide U.S. dollar funding under contractually committed U.S. credit facilities. Additionally, CA has announced that it is divesting its U.S. hedging holdings and activities. We are unaware of any announced divestitures by Natixis. In light of the preceding challenges confronting our French bank credit providers, and despite the numerous mitigants to offset the situation, we cannot assure that we can replace the borrowing capacity being provided to us by the French Banks should the need arise, or that the French Banks will continue to perform under our revolving credit facility or as hedging counterparties in the future. Should we be unable to replace such borrowing capacity, or should the French Banks fail to perform, those events could have a material adverse effect on our operations and financial condition.

While we believe that we will be able to find other banking institutions to be effective counterparties for our derivatives instruments in the future, it is possible that the loss of the French Banks from the class of available banking institutions that become counterparties for U.S. derivative instruments will significantly reduce the number of banking institutions that write such instruments and serve as counterparties. In this event, it is possible that we might not be able to find comparable counterparties to write derivatives instruments as readily as before the French Banks determined to leave the U.S. hedging market. Additionally, even if we are readily able to contract with such counterparties, the cost of these derivatives instruments might be greater than those that we have to date become a party to, thereby diminishing the economic effectiveness of those derivatives instruments that we in fact do write. Moreover, it is possible that with new counterparties to our derivatives instruments the risk of counterparty default on such derivatives instruments might increase.

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ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
January 1 - 31, 2012	1,309	$33.92	—	—
February 1 - 29, 2012	2,020	34.30	—	—
March 1 - 31, 2012	6,839	37.21	—	—
Total	10,168	36.21		

(1) Purchases primarily represent shares purchased 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. MINE SAFETY DISCLOSURES - Not applicable

ITEM 5. OTHER INFORMATION - None

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PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)

ITEM 6. EXHIBITS

With the exception of the following additions, there have been no material changes in the exhibits index previously disclosed in our 2011 Form 10-K.

Exhibit		Incorporated by Reference				Filed
Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Herewith
10.1	Third Amendment to the Second Amended and Restated Credit Agreement, dated as of May 4, 2012.					X
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.					
101.INS *	XBRL Instance Document					
101.SCH *	XBRL Taxonomy Extension Schema Document					
101.CAL *	XBRL Taxonomy Extension Calculation Linkbase Document					
101.DEF *	XBRL Taxonomy Extension Definition Linkbase Document					
101.LAB *	XBRL Taxonomy Extension Label Linkbase Document					
101.PRE *	XBRL Taxonomy Extension Presentation Linkbase Document					

* Furnished herewith.

SIGNATURES

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

Petroleum Development Corporation
(Registrant)

Date: May 10, 2012

/s/ James M. Trimble
James M. Trimble,
President 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)