PDC ENERGY, INC.
Form 10-Q
August 02, 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 June 30, 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
PDC ENERGY, INC.
(Exact name of registrant as specified in its charter)

Nevada (State or other jurisdiction of incorporation or organization)	95-2636730 (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: 30,257,261 shares of the Company's Common Stock ($0.01 par value) were outstanding as of July 20, 2012.

EXPLANATORY NOTE
At our annual meeting of stockholders held on June 7, 2012, the stockholders approved a change of the Company's legal name from Petroleum Development Corporation to PDC Energy, Inc. As of July 16, 2012, our common stock trades on the NASDAQ Global Select Market under the ticker symbol "PDCE."

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PDC ENERGY, INC.

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q 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 relate to, among other things: 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 and operations; that our liquidity will be sufficient to allow us to execute on our accelerated drilling program in the Wattenberg Field and continue to pursue potential acquisitions; the ability to get additional Marcellus wells turned-in-line in 2012; increased focus on the Wattenberg Field and liquid-rich areas and pursuit of strategic and complementary acquisitions in the Niobrara and Utica plays; 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; that our derivative program was effective in providing price stability despite a significant decrease in natural gas prices; the expected additional 180 horizontal drilling locations from the newly acquired Wattenberg Field assets; the sufficiency of our monitoring procedures for the creditworthiness of our financial institution counterparties; our expected remaining liability for uncertain tax positions; our ability to secure a joint venture partner for our Utica Shale acreage; that we do not expect to declare or pay dividends in the foreseeable future; 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; the availability of adequate takeaway capacity and related services and the timing of construction of future takeaway and related facilities; and our future 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 policies 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;
- potential declines 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 the prices we receive for our production;
- 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 Quarterly Report on Form 10-Q, 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 our business, financial condition, results of operations and

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prospects, which are incorporated by this reference as though fully set forth herein. We caution you not to place undue reliance on forward-looking statements, which speak only as of the date of this report. We undertake no obligation to update any forward-looking statements in order to reflect any event or circumstance occurring after the date of this report or currently unknown facts or conditions or the occurrence of unanticipated events. All forward-looking statements are qualified in their entirety by this cautionary statement.

REFERENCES

Unless the context otherwise requires, references in this report to "PDC," "PDC Energy," "the Company," "we," "us," "our," "ours," "ourselves" or other such terms refer to the registrant, PDC Energy, Inc., 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 and formed for the purpose of exploring and developing the Marcellus Shale formation in the Appalachian Basin. Unless the context otherwise requires, references in this report to "Appalachian Basin" include PDC's proportionate share of our affiliated partnerships' and PDCM'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" and "the six months ended 2012" refer to the three and six month periods ended June 30, 2012, respectively. References to "the three months ended 2011" and "the six months ended 2011" refer to the three and six month periods ended June 30, 2011, respectively.

References to "quarter-over-quarter" refer to the three months ended 2012 compared to the three months ended 2011. References to "year-over-year" refer to the six months ended 2012 compared to the six months ended 2011.

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PART I - FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

PDC ENERGY, INC.
Condensed Consolidated Balance Sheets
(unaudited; in thousands, except share and per share data)

	June 30, 2012	December 31, 2011 (1)
Assets		
Current assets:		
Cash and cash equivalents	$5,956	$8,238
Restricted cash	2,240	11,070
Accounts receivable, net	56,345	59,923
Accounts receivable affiliates	7,438	8,518
Fair value of derivatives	71,217	60,809
Prepaid expenses and other current assets	10,674	24,492
Total current assets	153,870	173,050
Properties and equipment, net	1,680,411	1,301,716
Assets held for sale	—	148,249
Fair value of derivatives	35,920	41,175
Accounts receivable affiliates	1,437	2,836
Other assets	46,190	30,979
Total Assets	$1,917,828	$1,698,005
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$53,233	$76,027
Accounts payable affiliates	10,600	10,176
Production tax liability	27,189	18,949
Fair value of derivatives	18,155	27,974
Funds held for distribution	29,368	28,594
Accrued interest payable	10,249	11,243
Other accrued expenses	33,255	22,083
Total current liabilities	182,049	195,046
Long-term debt	591,976	532,157
Deferred income taxes	192,733	207,573
Asset retirement obligations	59,856	46,316
Fair value of derivatives	13,575	21,106
Accounts payable affiliates	3,284	6,134
Other liabilities	15,511	25,561
Total liabilities	1,058,984	1,033,893
Commitments and contingent liabilities		
Shareholders' equity:		
Preferred shares - par value $0.01 per share, 50,000,000 shares authorized, none issued	—	—
Common shares - par value $0.01 per share, 100,000,000 authorized, 30,261,150 and 23,634,958 issued as of June 30, 2012 and December 31, 2011, respectively	303	236

Additional paid-in capital	384,275	217,707
Retained earnings	474,386	446,280
Treasury shares - at cost, 3,204 and 2,938 as of June 30, 2012 and December 31, 2011, respectively	(120)	(111)
Total shareholders' equity	858,844	664,112
Total Liabilities and Shareholders' Equity	$1,917,828	$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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PDC ENERGY, INC.
Condensed Consolidated Statements of Operations
(unaudited; in thousands, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Revenues:				
Natural gas, NGL and crude oil sales	$56,879	$65,762	$132,189	$124,572
Sales from natural gas marketing	8,917	18,897	20,751	34,099
Commodity price risk management gain (loss), net	38,729	20,537	50,230	(3,345)
Well operations, pipeline income and other	1,520	1,755	3,221	3,598
Total revenues	106,045	106,951	206,391	158,924
Costs, expenses and other:				
Production costs	18,880	16,895	38,069	35,367
Cost of natural gas marketing	8,761	18,207	20,253	33,200
Exploration expense	2,570	1,215	4,633	2,884
Impairment of natural gas and crude oil properties	370	499	1,023	952
General and administrative expense	14,378	19,509	29,086	33,382
Depreciation, depletion and amortization	34,448	30,592	74,262	61,577
Gain on sale of properties and equipment	(2,246)	—	(2,400)	—
Total costs, expenses and other	77,161	86,917	164,926	167,362
Income (loss) from operations	28,884	20,034	41,465	(8,438)
Interest income	—	2	2	11
Interest expense	(10,053)	(9,067)	(20,497)	(18,129)
Income (loss) from continuing operations before income taxes	18,831	10,969	20,970	(26,556)
Provision for income taxes	6,179	2,804	6,938	(11,474)
Income (loss) from continuing operations	12,652	8,165	14,032	(15,082)
Income (loss) from discontinued operations, net of tax	(381)	1,000	14,074	4,323
Net income (loss)	$12,271	$9,165	$28,106	$(10,759)
Earnings per share:				
Basic				
Income (loss) from continuing operations	$0.48	$0.35	$0.56	$(0.64)
Income (loss) from discontinued operations	(0.02)	0.04	0.56	0.18
Net income (loss)	$0.46	$0.39	$1.12	$(0.46)
Diluted				
Income (loss) from continuing operations	$0.47	$0.35	$0.55	$(0.64)
Income (loss) from discontinued operations	(0.01)	0.04	0.56	0.18
Net income (loss)	$0.46	$0.39	$1.11	$(0.46)
Weighted-average common shares outstanding:				
Basic	26,597	23,491	25,103	23,460
Diluted	26,728	23,723	25,268	23,460

See accompanying Notes to Condensed Consolidated Financial Statements

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PDC ENERGY, INC.
Condensed Consolidated Statements of Cash Flows
(unaudited, in thousands)

	Six Months Ended June 30, 2012	2011
Cash flows from operating activities:		
Net income (loss)	$28,106	$(10,759)
Adjustments to net income (loss) to reconcile to net cash from operating activities:		
Unrealized (gain) loss on derivatives, net	(24,079)	9,094
Depreciation, depletion and amortization	74,262	65,031
Impairment of natural gas and crude oil properties	1,023	952
Exploratory dry hole costs	401	171
Gain on sale of properties and equipment	(22,331)	(3,854)
Deferred income taxes	12,330	(10,543)
Stock-based compensation	3,901	5,549
Amortization of debt discount and issuance costs	3,547	3,400
Other	1,546	1,152
Changes in assets and liabilities	(9,011)	11,401
Net cash from operating activities	69,695	71,594
Cash flows from investing activities:		
Capital expenditures	(165,157)	(151,355)
Acquisition of natural gas and crude oil properties	(309,285)	—
Proceeds from acquisition adjustments	11,969	—
Proceeds from the sale of properties and equipment	187,340	10,062
Other	(17,497)	1,542
Net cash from investing activities	(292,630)	(139,751)
Cash flows from financing activities:		
Proceeds from credit facility	483,250	65,927
Payment of credit facility	(425,250)	(49,526)
Proceeds from sale of equity, net of issuance costs	164,050	—
Contribution by investing partner in PDCM	—	6,407
Other	(1,397)	(2,252)
Net cash from financing activities	220,653	20,556
Net change in cash and cash equivalents	(2,282)	(47,601)
Cash and cash equivalents, beginning of period	8,238	54,372
Cash and cash equivalents, end of period	$5,956	$6,771
Supplemental cash flow information:		
Cash payments for:		
Interest, net of capitalized interest	$17,918	$14,328
Income taxes, net of refunds	1,468	148
Non-cash investing activities:		
Change in accounts payable related to purchases of properties and equipment	(12,927)	48,572
Change in asset retirement obligation, with a corresponding change to natural gas and crude oil properties, net of disposals	11,934	304
See Note 12 for non-cash transactions related to our acquisition		

See accompanying Notes to Condensed Consolidated Financial Statements

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PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
JUNE 30, 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 June 30, 2012, we owned an interest in approximately 7,300 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 our 21 affiliated partnerships. Pursuant to the proportionate consolidation method, our accompanying condensed 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 condensed consolidated 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 and six 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, specifically related to discontinued operations. See Note 13 for additional information regarding our discontinued operations. We also reclassified the impairment and amortization charges recorded for unproved properties out of the statement of operations line item exploration expense and into impairment of natural gas and crude oil properties. The reclassifications 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 Financial Accounting Standards Board ("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 and U.S. GAAP. The changes expand existing disclosure requirements for fair value measurements categorized in Level 3 by requiring a quantitative disclosure of the unobservable inputs and assumptions used in the measurement, a description of the valuation processes in place and 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 for interim and annual periods beginning after December 15, 2011. Adoption of these changes did not have a significant impact on our financial statements.

NOTE 3 - FAIR VALUE MEASUREMENTS AND DISCLOSURES

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) for identical assets or liabilities in active markets.

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

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity.

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 the review of counterparty statements and other supporting documentation, the determination that the source of the inputs is valid, the corroboration of the original source of inputs through access to multiple quotes, if available, or other information and 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, 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 potential impact of nonperformance of our counterparties on the fair value of our derivative instruments was not significant.

Our fixed-price swaps, basis swaps and physical purchases are included in Level 2 and our natural gas and crude oil collars, crude oil puts and physical sales are included in Level 3. The following table presents, for each applicable level within the fair value hierarchy, our derivative assets and liabilities, including both current and non-current portions, measured at fair value on a recurring basis:

	June 30, 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	$78,442	$ 28,649	$ 107,091	$76,104	$ 25,837	$ 101,941
Basis protection derivative contracts	25	21	46	5	38	43
Total assets	78,467	28,670	107,137	76,109	25,875	101,984
Liabilities:						
Commodity based derivatives contracts	5,153	70	5,223	9,888	3,768	13,656
Basis protection derivative contracts	26,507	—	26,507	35,424	—	35,424

Total liabilities	31,660	70	31,730	45,312	3,768	49,080
Net asset	$46,807	$ 28,600	$75,407	$30,797	$ 22,107	$52,904

The following table presents a reconciliation of our Level 3 assets measured at fair value:

	Six Months Ended June 30,	
	2012	2011
	(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	15,153	(2,108)
Sales from natural gas marketing	39	20
Changes in fair value included in balance sheet line item (1):		
Accounts receivable affiliates	—	49
Accounts payable affiliates	(146)	(637)
Settlements included in statement of operations line items:		
Commodity price risk management loss, net	(8,458)	(2,210)
Sales from natural gas marketing	(95)	(86)
Fair value, net asset, end of period	$28,600	$5,790
Changes in unrealized gains (losses) relating to assets (liabilities) still held as of period end, included in statement of operations line item:		
Commodity price risk management gain (loss), net	$8,661	$(1,809)
Sales from natural gas marketing	1	(5)
Total	$8,662	$(1,814)

(1) 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, which 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 included in 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.

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 related interest rates. 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 June 30, 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 $108.2 million, or 94.1% of par value, and the portion related to our 12% senior notes due 2018 to be $215.7 million, or 106.3% 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 are Level 1 inputs.

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PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

NOTE 4 - DERIVATIVE FINANCIAL INSTRUMENTS

As of June 30, 2012, we had derivative instruments in place for a portion of our anticipated production through 2016 totaling 81,215 BBtu of natural gas and 3,906 MBbls of crude oil.

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

Derivatives instruments not designated as hedges (1):		Balance sheet line item	Fair Value June 30, 2012	December 31, 2011
			(in thousands)	
Derivative assets:	Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	$62,626	$51,220
	Related to affiliated partnerships (2)	Fair value of derivatives	7,770	8,018
	Related to natural gas marketing	Fair value of derivatives	792	1,528
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	29	43
			71,217	60,809
	Non-Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	32,405	34,938
	Related to affiliated partnerships (2)	Fair value of derivatives	3,284	6,134
	Related to natural gas marketing	Fair value of derivatives	214	103
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	17	—
			35,920	41,175
Total derivative assets			$107,137	$101,984
Derivative liabilities:	Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	$(984)	$7,498
	Related to affiliated partnerships (3)	Fair value of derivatives	211	211
	Related to natural gas marketing	Fair value of derivatives	732	1,384
	Basis protection contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	15,202	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
			18,155	27,974
	Non-Current			
	Commodity contracts			

	Related to natural gas and crude oil sales	Fair value of derivatives	5,021	4,357
	Related to affiliated partnerships (3)	Fair value of derivatives	73	113
	Related to natural gas marketing	Fair value of derivatives	170	93
	Basis protection contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	6,947	13,820
	Related to affiliated partnerships (3)	Fair value of derivatives	1,364	2,723
			13,575	21,106
Total derivative liabilities			$31,730	$49,080

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(1) As of June 30, 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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PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

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

Statement of Operations Line Item	2012 Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	2012 Realized and Unrealized Gains (Losses) For the Current Period	2012 Total	2011 Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	2011 Realized and Unrealized Gains (Losses) For the Current Period	2011 Total
	(in thousands)					
Three Months Ended June 30,						
Commodity price risk management gain, net						
Realized gains	$13,503	$2,676	$16,179	$763	$1,040	$1,803
Unrealized gains (losses)	(13,503)	36,053	22,550	(763)	19,497	18,734
Total commodity price risk management gain, net	$—	$38,729	$38,729	$—	$20,537	$20,537
Sales from natural gas marketing						
Realized gains	$749	$3	$752	$473	$19	$492
Unrealized gains (losses)	(749)	(322)	(1,071)	(473)	456	(17)
Total sales from natural gas marketing	$—	$(319)	$(319)	$—	$475	$475
Cost of natural gas marketing						
Realized losses	$(692)	$(26)	$(718)	$(370)	$(31)	$(401)
Unrealized gains (losses)	692	375	1,067	370	(436)	(66)
Total cost of natural gas marketing	$—	$349	$349	$—	$(467)	$(467)
Six Months Ended June 30,						
Commodity price risk management gain, net						
Realized gains	$16,046	$10,060	$26,106	$6,612	$(1,021)	$5,591
Unrealized gains (losses)	(16,046)	40,170	24,124	(6,612)	(2,324)	(8,936)
Total commodity price risk management gain (loss), net	$—	$50,230	$50,230	$—	$(3,345)	$(3,345)
Sales from natural gas marketing						
Realized gains	$1,110	$435	$1,545	$1,373	$261	$1,634
Unrealized gains (losses)	(1,110)	114	(996)	(1,373)	339	(1,034)
Total sales from natural gas marketing	$—	$549	$549	$—	$600	$600
Cost of natural gas marketing						
Realized losses	$(970)	$(493)	$(1,463)	$(1,076)	$(285)	$(1,361)
Unrealized gains (losses)	970	(19)	951	1,076	(200)	876
Total cost of natural gas marketing	$—	$(512)	$(512)	$—	$(485)	$(485)

Derivative Counterparties. Our derivative arrangements expose us to credit risk of nonperformance by our counterparties. We primarily use financial institutions who are also lenders under our credit facility 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, we have determined that the potential impact of nonperformance of our counterparties on the fair value of our derivative instruments was not significant.

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PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following table presents the counterparties that expose us to credit risk as of June 30, 2012, with regard to our derivative assets:

Counterparty Name	Fair Value of Derivative Assets As of June 30, 2012 (in thousands)
JPMorgan Chase Bank, N.A. (1)	$54,713
Wells Fargo Bank, N.A. (1)	14,511
Crèdit Agricole CIB (1)	11,453
Other lenders in our credit facility	25,117
Various (2)	1,343
Total	$107,137

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(1)Major lender in our credit facility, see Note 7.
(2)Represents a total of 18 counterparties.

NOTE 5 - PROPERTIES AND EQUIPMENT

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

	June 30, 2012	December 31, 2011
	(in thousands)	
Properties and equipment, net:		
Natural gas and crude oil properties		
Proved	$1,931,754	$1,694,694
Unproved	331,729	102,466
Total natural gas and crude oil properties	2,263,483	1,797,160
Pipelines and related facilities	42,237	40,721
Transportation and other equipment	33,224	32,475
Land and buildings	14,954	14,572
Construction in progress	52,476	69,633
Gross properties and equipment	2,406,374	1,954,561
Accumulated depreciation, depletion and amortization	(725,963)	(652,845)
Properties and equipment, net	$1,680,411	$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 expense 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 rates for continuing operations for the three and six months ended 2012 were 32.8% and 33.1%, respectively, compared to 25.6% and 43.2% for the three and six months ended 2011, respectively. The effective tax rates for the three and six months ended 2012 differ from the statutory rate primarily due to net permanent deductions, largely percentage depletion partially offset by nondeductible officer's compensation. The effective tax rates for the three and six months ended 2011 differ from the statutory rate primarily due to net permanent deductions, largely percentage depletion, decreasing the tax provision on income for the three months ended and increasing the tax benefit on loss for the six months ended June 30, 2011. There were no significant discrete items recorded during 2012. In the three and six months ended 2011 a discrete tax benefit of $0.6 million was recorded due to realization of uncertain tax benefits primarily because of a settlement with the IRS.

As of June 30, 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, this liability would affect our effective tax rate. This liability is reflected in other accrued expenses on our

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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.

NOTE 7 - LONG-TERM DEBT

Long-term debt consisted of the following:

	June 30, 2012	December 31, 2011
	(in thousands)	
Senior notes		
3.25% Convertible senior notes due 2016:		
Principal amount	$115,000	$115,000
Unamortized discount	(15,406)	(17,079)
3.25% Convertible senior notes due 2016, net of discount	99,594	97,921
12% Senior notes due 2018:		
Principal amount	203,000	203,000
Unamortized discount	(1,618)	(1,764)
12% Senior notes due 2018, net of discount	201,382	201,236
Total senior notes	300,976	299,157
Credit facilities		
Corporate	265,000	209,000
PDCM	26,000	24,000
Total credit facilities	291,000	233,000
Total long-term debt	$591,976	$532,157

Senior Notes

3.25% Convertible Senior Notes Due 2016. In 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 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 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 June 30, 2012, and expect to remain in compliance throughout the next twelve-month period.

Credit Facilities

Corporate Credit Facility. On June 29, 2012, concurrent with the acquisition of certain Wattenberg assets from affiliates of Merit Energy (the "Merit Acquisition"), we entered into a Fifth Amendment to our Second Amended and Restated Credit Agreement, dated as of November 5, 2010, with JPMorgan Chase Bank, N.A. as Administrative Agent and other lenders party thereto. The Fifth Amendment increased our available borrowing base to $525 million from $425 million based on our natural gas and crude oil reserves as of December 31, 2011 and the reserves as of April 1, 2012 for the acquired assets from the Merit Acquisition. The maximum allowable facility amount is $600 million. The credit facility is available for working capital requirements, capital expenditures, acquisitions, general corporate purposes and to support letters of credit.

On June 25, 2012, we entered into the Fourth Amendment to our credit facility. The Fourth Amendment amends certain provisions of the credit facility so as to allow us greater flexibility in entering into hedging transactions in connection with future potential asset transactions. Our credit facility borrowing base is subject to size redetermination semiannually based on quantification of our reserves at June 30 and December 31, and is also subject to a redetermination upon the occurrence of certain events. On May 4, 2012, we entered into the Third Amendment to our credit facility and, as a result of the semi-annual redetermination by our bank group, our borrowing base was increased by $25 million to $425 million. 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.

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 June 30, 2012) for the period the letter of credit remains outstanding. The letter of credit expires on July 20, 2013.

As of June 30, 2012, we had an outstanding balance of $265 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 June 30, 2012, the available funds under our credit facility, including a reduction for the $18.7 million irrevocable standby letter of credit in effect, was $241.3 million. The weighted-average borrowing rate on our credit facility, exclusive of the letter of credit, was 4.6% per annum as of June 30, 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 May 11, 2012, with an aggregate revolving commitment or borrowing base of $80 million, of which our proportionate share is $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 June 30 and December 31. 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 development of its Appalachian assets. As of June 30, 2012, our proportionate share of PDCM's outstanding credit facility draw was $26 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 June 30, 2012, both the Company and PDCM were in compliance with all 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 and assumed with acquisitions	13,995
Accretion expense	1,643
Obligations discharged with disposal of properties and asset retirements	(2,098)
Balance at June 30, 2012	60,106
Less current portion	(250)
Long-term portion	$59,856

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PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

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 our 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 any further volume shortfalls, if any, will be borne by PDC.

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 June 30,						
Area	2013	2014	2015	2016	2017 Through Expiration	Total	Expiration Date
Volume (MMcf)							
Piceance Basin	19,740	39,259	33,207	28,127	98,171	218,504	May 31, 2021
Appalachian Basin (1)	18,466	20,807	22,855	24,527	157,592	244,247	September 30, 2025
NECO	2,740	1,825	1,825	1,825	915	9,130	December 31, 2016
Total	40,946	61,891	57,887	54,479	256,678	471,881	
Dollar commitment (in thousands)	$19,161	$30,197	$27,430	$25,098	$97,298	$199,184	

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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 8,822 MMcf of the total MMcf presented for the twelve months ending June 30, 2013, 10,627 MMcf for each of the twelve months ending June 30, 2014 through 2016 and 31,882 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 U.S. District Court for the Central District of California, and is titled Schulein v. Petroleum Development Corp. The complaint primarily alleges a claim that the proxy statements issued in connection with the mergers were inadequate, and a state law breach of fiduciary duty. On February 10, 2012, the Company filed a motion to dismiss or in the alternative to stay. On June 15, 2012, the Court denied the motion. The court has approved a litigation schedule including a jury trial in May 2014. We have not recorded a liability for claims pending because we believe we have good legal defenses to the asserted claims.

Royalty Owner Class Action

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, titled, Gobel et al v. Petroleum Development Corporation, filed on January 27, 2009, in Circuit Court of Harrison County, CA No. 09-C-40-2. The allegations stated that the Company improperly deducted certain charges and costs before applying the royalty percentage.

On June 15, 2011, the Company entered into a settlement agreement with respect to this lawsuit, settling all claims between the parties for an aggregate payment of $8.7 million, subject to court approval. Final approval of the 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 June 30, 2012 and December 31, 2011, we had accrued environmental liabilities in the amount of $11.4 million and $2.5 million, respectively, included in other accrued expenses on the balance sheet. The increase relates to environmental liabilities assumed following the Merit Acquisition. See Note 12, Acquisitions, for a discussion of the Merit Acquisition. We are not aware of any environmental claims existing as of June 30, 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 June 30, 2012, the maximum annual repurchase obligation, based upon the minimum price described above, was approximately $4.1 million. We believe we have adequate liquidity to meet this obligation. For the three and six 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. If 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 vesting of any unvested equity compensation (excluding all long-term incentive shares), reimbursement for any unpaid expenses, continued coverage under our medical plan at the Company's cost for the federal COBRA health continuation coverage period and 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 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, 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, any unpaid expense reimbursement and 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, 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, in the case of disability, will be up to thirteen weeks of ongoing base salary plus a lump sum equal to six months of base salary.

NOTE 10 - COMMON STOCK

Sale of Equity Securities
In May, 2012, we completed a public offering of 6,500,000 shares of our common stock, par value $0.01 per share, at an offering price of $26.50 per share. Net proceeds of the offering were approximately $164 million, after deducting underwriting discounts and commissions and offering expenses, of which $65,000 is included in common shares-par value and $163.9 million is included in additional paid-in capital ("APIC") on the balance sheet. We used the net proceeds to finance a portion of the Merit Acquisition and for general corporate purposes. The offering was made pursuant to an effective shelf registration statement on Form S-3 filed with the SEC on January 23, 2012.
See Note 12, Acquisitions, for a discussion related to the Merit Acquisition.
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 June 30,		Six Months Ended June 30,	
	2012	2011 (1)	2012	2011 (1)
	(in thousands)			
Total stock-based compensation expense	$1,955	$4,004	$3,901	$5,549
Income tax benefit	(744)	(1,521)	(1,486)	(2,108)
Net expense	$1,211	$2,483	$2,415	$3,441

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(1) Includes a total of $2.5 million, pretax, related to a separation agreement with our former chief executive officer.

Stock Appreciation Rights ("SARs")

The SARs 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 January 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 following assumptions:

	Six Months Ended June 30,	
	2012	2011
Expected term	6 years	6 years
Risk-free interest rate	1.1%	2.5%
Expected volatility	64.3%	60.2%
Weighted-average grant date fair value per share	$17.61	$25.22

The expected term 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. The expected volatility was based on our historical volatility. We do not expect to pay or declare dividends in the foreseeable future.

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The following table presents the changes in our SARs:

	Six Months Ended June 30,							
	2012				2011			
	Number of SARs	Weighted -Average Exercise Price	Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)	Number of SARs	Weighted -Average Exercise Price	Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding beginning of year, January 1,	50,471	$ 31.61	8.6	$ 341	57,282	$ 24.44	9.3	$ 1,020
Granted	68,361	30.19	9.5	—	31,552	43.95	9.7	—
Outstanding at June 30,	118,832	30.80	8.9	3	88,834	31.37	5.3	313
Vested and expected to vest at June 30,	112,285	30.76	8.9	3	84,851	31.27	5.0	302
Exercisable at June 30,	27,458	28.84	8.0	2	48,999	29.61	2.1	197

The total compensation cost related to SARs granted and not yet recognized in our statement of operations as of June 30, 2012 was $1.3 million. The cost is expected to be recognized over a weighted-average period of 2.2 years. Pursuant to a separation agreement with our former chief executive officer and the original terms of the award, during the three and six months ended 2011, the vesting of 29,906 SARs was accelerated resulting in the acceleration of $0.6 million in stock-based compensation expense.

Restricted Stock Awards

Time-Based Awards. The fair value of the time-based restricted shares is amortized ratably over the requisite service period, primarily three or four years. The time-based shares vest ratably on each annual anniversary following the grant date that a participant is continuously employed.

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

The following table presents the changes in nonvested time-based awards for the six months ended 2012:

	Shares	Weighted-Average Grant-Date Fair Value per Share
Nonvested at December 31, 2011	527,801	$29.29
Granted	129,643	29.58
Vested	(131,015)	30.20
Forfeited	(12,498)	27.76
Nonvested at June 30, 2012	513,931	29.23

	As of / Six Months Ended June 30,	
	2012	2011

	(in thousands, except per share data)	
Total intrinsic value of time-based awards vested	$4,315	$7,185
Total intrinsic value of time-based awards nonvested	12,602	14,293
Market price per common share as of June 30,	24.52	29.91
Weighted-average grant date fair value per share	29.58	37.42

The total compensation cost related to nonvested time-based awards expected to vest and not yet recognized in our statements of operations as of June 30, 2012 was $11 million. This cost is expected to be recognized over a weighted-average period of 2.2 years. Pursuant to a separation agreement with our former chief executive officer and the original terms of the award, during the three and six months ended 2011, the vesting of 64,442 time-based restricted shares was accelerated, resulting in the acceleration of $1.9 million in stock-based compensation expense.

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PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

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 January 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 following assumptions:

	Six Months Ended June 30,			
	2012		2011	
Expected term	3 years		3 years	
Risk-free interest rate	0.3	%	1.1	%
Expected volatility	65.3	%	74.2	%
Weighted-average grant date fair value per share	$36.54		$58.53	

The expected term of the awards was 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 and extrapolated to approximate the life of the award. The expected volatility was based on our historical volatility. We do not expect to pay or declare dividends in the foreseeable future.

The following table presents the change in nonvested market-based awards for the six months ended 2012:

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

The total compensation cost related to nonvested market-based awards expected to vest and not yet recognized in our statement of operations as of June 30, 2012 was $1.1 million. This cost is expected to be recognized over a weighted-average period of 2.3 years. Pursuant to a separation agreement with our former chief executive officer and the original terms of the award, during the three and six months ended 2011, the vesting of 4,109 market-based restricted shares was accelerated and 21,927 market-based restricted shares were forfeited. The impact on stock-based compensation for the vesting and forfeiture of these market-based restricted shares was immaterial.

Treasury Share Purchases

In accordance with our stock-based compensation plans, employees and directors may surrender shares of common stock to cover tax withholding obligations upon the vesting or exercise of stock-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 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 six months ended June 30, 2012, we acquired 31,631 shares pursuant to our stock-based compensation plans for payment of tax liabilities, of which 11,701 shares were retired and the remaining 19,930 shares were reissued pursuant to our 2010 Plan.

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NOTE 11 - EARNINGS PER SHARE

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			
Weighted-average common shares outstanding - basic	26,597	23,491	25,103	23,460
Dilutive effect of share-based compensation:				
Restricted stock	125	181	157	—
SARs	3	48	4	—
Non-employee director deferred compensation	3	3	4	—
Weighted-average common and common share equivalents outstanding - diluted	26,728	23,723	25,268	23,460

The following table sets forth the weighted-average common share equivalents excluded from the calculation of diluted earnings per share due to their anti-dilutive effect:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			
Weighted-average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:				
Restricted stock	90	102	64	587
Stock options	7	10	7	10
SARs	87	32	81	77
Non-employee director deferred compensation	—	—	—	3
Total anti-dilutive common share equivalents	184	144	152	677

In November 2010, we issued 115,000 convertible senior notes, $1,000 principal amount per note, that give the holders the right to convert the aggregate 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 market share price did not exceed $42.40 per share during the three and six months ended 2012 or 2011.

NOTE 12 - ACQUISITIONS

Merit Acquisition. On June 29, 2012, we completed the acquisition of certain Wattenberg Field oil and natural gas properties, leasehold mineral interests and related assets located in Weld, Adams and Boulder Counties, Colorado from affiliates of Merit Energy, an unrelated third-party. The aggregate purchase price of these properties was approximately $326.8 million based upon a transaction effective date of April 1, 2012, subject to certain post-closing adjustments. We financed the purchase with cash from the May 2012 offering of our common stock and a draw on our corporate credit facility. At closing, $17.5 million was deposited into an escrow account for curative title work related to leases and other matters in accordance with the purchase and sale agreement, and is included in other assets on the balance sheet. If the seller is unable to cure the title defect for a particular lease within a specified period of time, the designated amount of the escrow account assigned to that lease will be paid to us from the escrow account. If the seller is able to cure the defects, this amount will be paid to the seller and recorded as a purchase price adjustment increasing properties and equipment.

This acquisition was accounted for under the acquisition method of accounting. Accordingly, we conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while transaction and integration costs associated with the acquisition were expensed as incurred. The initial accounting for the business combination is based on preliminary data and is not complete. Adjustments to provisional amounts, or recognition of additional assets acquired or liabilities assumed, may occur as more detailed analyses are completed and additional information is obtained about the facts and circumstances that existed as of the acquisition date.

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The following presents the preliminary values assigned to the net assets acquired as of the acquisition date:

	(in thousands)
Total acquisition cost	$326,782
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Assets acquired:	
Natural gas and crude oil properties - proved	$126,101
Natural gas and crude oil properties - unproved	208,098
Other assets	23,589
Total assets acquired	357,788
Liabilities assumed:	
Asset retirement obligation	13,870
Environmental liability	10,100
Other liabilities	7,036
Total liabilities assumed	31,006
Total identifiable net assets acquired	$326,782

The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of reserves, future operating and development costs, future commodity prices, estimated future cash flows and a market-based weighted-average cost of capital rate. These inputs require significant judgments and estimates by management at the time of the valuation and are the most sensitive and subject to change.

Pro Forma Information. The results of operations for the above acquisition has been included in our consolidated financial statements since the June 29, 2012 closing date. The following unaudited pro forma financial information presents a summary of the condensed consolidated results of operations for the three months and six months ended June 30, 2012 and June 30, 2011, assuming the acquisition had been completed as of January 1, 2011, including adjustments to reflect the values assigned to the net assets acquired. The pro forma financial information is not necessarily indicative of the results of operations that would have been achieved if the acquisition had been effective as of these dates, or of future results.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands, except per share amounts)			
Total revenues	$111,754	$118,482	$220,746	$147,169
Total costs, expenses and other	78,125	87,727	167,457	172,645
Net income	16,087	19,336	38,773	5,455
Earnings per share:				
Basic	$0.60	$0.82	$1.54	$0.23
Diluted	$0.60	$0.82	$1.53	$0.23

Seneca-Upshur. Following PDCM's October 2011 acquisition of Seneca-Upshur, several title defects were discovered that were not cured by the seller within the time specified by the purchase and sale agreement. Accordingly, to date PDCM received title defect payments of approximately $24 million, of which $12 million represents our share. These payments were recorded as a purchase price adjustment reducing unproved natural gas and crude oil properties; the refund for these title defects reduced the purchase price from $162.9 million down to $138.9 million, with our portion being $69.5 million. The final payment to PDCM for title defects is subject to additional adjustments.

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NOTE 13 - DIVESTITURES AND DISCONTINUED OPERATIONS

Permian Basin. In October 2011, we developed a plan to divest 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. Upon final settlement, total proceeds received were $189.2 million after closing adjustments, resulting in a pretax gain on sale of $19.9 million.

North Dakota. During the fourth quarter of 2010, we developed a plan to divest 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 executed 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 six 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 on 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 six 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 June 30,		Six Months Ended June 30,	
Statement of Operations - Discontinued Operations	2012	2011	2012	2011
	(dollars in thousands)			
Revenues				
Natural gas, NGL and crude oil sales	$—	$6,453	$4,456	$11,969
Well operations, pipeline income and other	—	26	34	69
Total revenues	—	6,479	4,490	12,038
Costs, expenses and other				
Production costs	—	2,779	1,668	5,478
Exploration expense	—	6	—	35

Depreciation, depletion and amortization	—	2,082	—	3,454
(Gain) loss on sale of properties and equipment	415	—	(19,920)	(3,854)
Total costs, expenses and other	415	4,867	(18,252)	5,113
Income (loss) from discontinued operations	(415)	1,612	22,742	6,925
Provision for income taxes	(34)	612	8,668	2,602
Income (loss) from discontinued operations, net of tax	$(381)	$1,000	$14,074	$4,323

NOTE 14 - 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 in the three and six months ended 2012, respectively, related to the marketing of natural gas on behalf of our affiliated partnerships, compared to $0.5 million and $0.7 million in the three and six months ended 2011, respectively. Our cost of natural gas marketing includes $0.1 million and $0.2 million in the three and six months ended 2012, respectively, compared to $0.4 million and $0.6 million in the three and six months ended 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 a portion of their estimated production. As of June 30, 2012 and December 31, 2011, we had a payable to affiliates of $11.1 million and $14.2 million, respectively, representing their designated portion of the fair value of our gross derivative assets, and a receivable from affiliates of $4.6 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 $2.2 million and $4.6 million in the three and six months ended 2012, respectively, related to the marketing of natural gas on behalf of PDCM, compared to $3.3 million and $5.1 million in the three and six months ended 2011, respectively. Our cost of natural gas marketing includes $2.1 million and $4.5 million in the three and six months ended 2012, respectively, compared to $3.3 million and $5.1 million in the three and six months ended 2011, respectively, related to these sales.

We provide certain well operating and administrative services for PDCM. Amounts billed to PDCM for these services were $3.0 million and $6.2 million in the three and six months ended 2012, respectively, compared to $2.2 million and $4.5 million in 2011. Our statements of operations include only our proportionate share of these billings.

Former Executive Officer. In June 2011, Richard W. McCullough resigned from his positions as our Chief Executive Officer and the Chairman of the Board, effective immediately. In connection with his resignation, in July 2011, Mr. McCullough and the Company executed a separation agreement whereby Mr. McCullough received those benefits to which he was entitled under Section 7(d) of his employment agreement, dated as of April 19, 2010, including without limitation separation compensation in the amount of $4.1 million, less required withholdings, his annual non-qualified deferred supplemental retirement benefit equal to $30,000 for each of the years 2012 through 2021 (not accelerated), less required withholdings, continued coverage under the Company's group health plans at the Company's cost for a period equal to the lesser of 18 months or such period ending as of the date Mr. McCullough is eligible to participate in another employer's group health plan, immediate vesting of any unvested Company stock options, SARs and restricted stock and issuance of shares representing the vested portion of his 2009 performance share awards. Related to this separation agreement, the statement of operations for 2011 reflects a charge to general and administrative expense of $6.7 million.

NOTE 15 - BUSINESS SEGMENTS

We separate our operating activities into two segments: Oil and Gas Exploration and Production and Gas Marketing. All material intercompany 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 revenues include 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 depreciation, depletion and amortization 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 depreciation, depletion and amortization expense, interest income and interest expense.

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The following tables present our segment information:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in thousands)			
Revenues:				
Oil and Gas Exploration and Production	$97,128	$88,054	$185,640	$124,825
Gas Marketing	8,917	18,897	20,751	34,099
Total	$106,045	$106,951	$206,391	$158,924
Segment income (loss) before income taxes:			—	
Oil and Gas Exploration and Production	$45,101	$39,623	$73,728	$25,579
Gas Marketing	156	690	498	899
Unallocated	(26,426)	(29,344)	(53,256)	(53,034)
Total	$18,831	$10,969	$20,970	$(26,556)

	June 30, 2012	December 31, 2011
	(in thousands)	
Segment assets:		
Oil and Gas Exploration and Production	$1,841,382	$1,461,130
Gas Marketing	9,888	14,713
Unallocated	66,558	73,913
Assets held for sale	—	148,249
Total	$1,917,828	$1,698,005

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

EXECUTIVE SUMMARY

Financial Overview

Driven by the success of our horizontal Niobrara program in the Wattenberg Field, crude oil production from continuing operations increased 22.1% and 45.7% in the three and six month periods in 2012, respectively, compared to the three and six month periods in 2011, while NGL production from continuing operations increased 41.2% and 47.8% in the three and six month periods in 2012, respectively. These significant increases improved our liquids percentage of total production from continuing operations to 33.5% and 34.8% for the three and six months ended 2012 compared to 29.1% and 28.0% for the same prior year periods. Additionally, natural gas production increased 3.6% and 6.5% in the three and six month periods of 2012, respectively, compared to the three and six month periods in 2011. As discussed under "Operational Overview-Production" below, production growth in the quarter was adversely affected by high line pressures experienced by our principal third-party provider of natural gas gathering, processing and transportation facilities in the Wattenberg Field. The high line pressure was the result of two primary factors: a series of operational issues experienced by the third-party downstream transportation and fractionation facilities during the second quarter 2012 and abnormally warm temperatures, which caused reduced efficiency in the third-party gatherer's compression facilities. While natural gas production increased slightly when compared to the same prior year period, significant declines in the average price of natural gas during 2012 resulted in a decrease in natural gas sales, excluding hedges, of 54.6% quarter-over-quarter and 40.7% year-over-year. The price of natural gas rebounded slightly in June and July.

While the significant decrease in the price of natural gas prices has impacted our results of operations, we believe our derivative program was effective in providing price stability. Realized gains from derivative transactions increased considerably to $16.2 million and $26.1 million during the three and six month periods ended 2012, respectively, compared to $1.8 million and $5.6 million during the three and six month periods ended 2011, respectively, an addition of approximately $1.40 and $1.06 per Mcfe produced during the three and six month periods ended 2012, respectively.

Available liquidity as of June 30, 2012 was $261.3 million, including $15.4 million through our joint venture PDCM, compared to $196.4 million, including $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. In May 2012, we completed a public offering of 6.5 million shares of our common stock for net proceeds of approximately $164 million, after deducting underwriting discounts and offering expenses. In May, we also completed the semiannual redetermination of our corporate credit facility's borrowing base, resulting in an increase in our available borrowing base from $400 million to $425 million. Upon completion of the Merit Acquisition in June, the credit facility's borrowing base was further increased from $425 million to $525 million. We believe we have sufficient liquidity to allow us to execute our accelerated drilling program in the Wattenberg Field and will consider potential acquisitions of oil and natural gas properties in our liquids-rich basins.

Operational Overview
During the second quarter of 2012, we made significant strides towards our strategic goal of increasing production and achieving a balanced production mix of natural gas and liquids. In June, we completed the Merit Acquisition for cash consideration of approximately $326.8 million. The acquired assets comprise approximately 35,000 net acres (subject

to post-closing adjustments) located almost entirely in the core Wattenberg Field and with significant overlay with our existing acreage position. We expect this to provide us with an additional 180 horizontal Niobrara drilling locations, as well as additional potential opportunities from Niobrara downspacing and horizontal Codell development. Additionally, we began operating a second drilling rig on our horizontal Niobrara acreage in early July of 2012.
Drilling Activities. During the six months ended 2012, we continued to focus our operations and leasehold acquisitions primarily in the oil- and liquids-rich Wattenberg Field of Colorado and the emerging Utica Shale play in Ohio. We drilled 13 horizontal wells in the Wattenberg Field, of which eight were completed and turned-in-line as of June 30, 2012, and participated in two horizontal and three vertical non-operated drilling projects. We also executed 103 refrac/recompletion projects on 55 wells in the Wattenberg Field. The shift in the Wattenberg Field from drilling 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 cost per well and higher production and reserves per well. The remaining activity in our Western Operating Region in the first six months of 2012 was the completion of our final three Piceance wells drilled in 2011.

We completed two vertical Utica wells in our Eastern Operating Region in the first six months of 2012, and have commenced drilling our first Utica horizontal well. During the first six months of 2012, we continued to increase our Utica Shale acreage in Ohio. We continue to hold discussions with various parties relating to the potential formation of a joint venture to aid in funding and developing the current acreage and expanding our acreage position in the Utica Shale. There can be no assurance we will be able to secure a joint venture partner on terms acceptable to PDC or at all.

In addition, PDCM drilled three horizontal Marcellus wells, all of which were completed during the first quarter, before laying down the rig due to the deterioration of natural gas prices in the Appalachian Basin. We have three additional horizontal Marcellus wells drilled which we expect will be turned-in-line during the fourth quarter of 2012.

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 certain 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 remaining Permian assets for a total price of $173.9 million, subject to customary post-closing adjustments. On February 28, 2012, the divestiture closed. Upon final post-closing adjustment on June 29, 2012, total proceeds received were $189.2 million, resulting in a pretax gain on sale of $19.9 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 execute on 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 applicable periods presented in the accompanying statements of operations included in this report.

Production. Production increased significantly in the six months ended 2012 relative to the same period in 2011. In particular, primarily as a result of our Wattenberg Field drilling activities, oil production increased 45.7% and NGL production increased 47.8%. Production growth, however, was adversely affected by high line pressures experienced by our principal third-party provider of natural gas gathering, processing and transportation facilities in the Wattenberg Field. The high line pressure was the result of two primary factors: a series of operational issues experienced by the third-party downstream transportation and fractionation facilities during the second quarter 2012 and abnormally warm temperatures, which caused reduced efficiency in the third-party gatherer's compression facilities. We are working closely with our primary midstream provider who is currently implementing a multi-year facility expansion capable of significantly increasing long-term gathering and processing capacity in the Wattenberg Field. However, we do not expect the impact of this increased capacity to substantially affect us until late 2013. Taking into account expected capacity availability, we currently expect that our production for 2012 will be approximately 51.5 Bcfe. Our expectations with respect to future production are subject to a wide variety of risks, including those described and referenced in the “Risk Factors” sections of this report and our 2011 Form 10-K. Our NGL pricing has also decreased significantly relative to the same period in 2011.

Our NGL's are priced at Conway, where ethane and propane are valued at a significant discount to Mt. Belvieu gulf coast NGL pricing. The planned 2013 infrastructure projects include a new NGL pipeline that will provide access for our NGL to Mt Belvieu and associated pricing.

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, sustained low natural gas prices could have a material adverse effect on us as a result of lower natural gas sales, a reduction in the estimated quantity of our proved reserves and a corresponding reduction in the estimated future net cash flows expected to be generated from these reserves. The above factors could result in, among other things, a reduction in the borrowing base under our credit facility and possible future asset impairments. See Item 3, Quantitative and Qualitative Disclosures About Market Risk.

Non-U.S. GAAP Financial Measures

We use "adjusted cash flow from operations," "adjusted net income (loss)" 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, nor 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 herein for a detailed description of these measures, as well as a reconciliation of each to the most comparable U.S. GAAP measure.

Results of Operations

Summary Operating Results

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	Percentage Change	2012	2011	Percentage Change
	(dollars in millions, except per unit data)					
Production (1)						
Natural gas (MMcf)	7,675.9	7,411.2	3.6 %	16,050.0	15,077.4	6.5 %
Crude oil (MBbls)	452.0	370.1	22.1 %	1,007.2	691.3	45.7 %
NGLs (MBbls)	192.5	136.3	41.2 %	421.3	285.1	47.8 %
Natural gas equivalent (MMcfe) (2)	11,543.5	10,450.0	10.5 %	24,621.3	20,935.9	17.6 %
Average MMcfe per day	126.9	114.8	10.5 %	135.3	115.7	16.9 %
Natural gas, NGL and crude oil sales						
Natural gas	$11.9	$26.2	(54.6)%	$29.4	$49.6	(40.7)%
Crude oil	39.8	34.9	14.0 %	91.2	63.7	43.2 %
NGLs	5.2	4.7	10.6 %	11.6	11.3	2.7 %
Total natural gas, NGL and crude oil sales	$56.9	$65.8	(13.5)%	$132.2	$124.6	6.1 %
Realized gain (loss) on derivatives, net (3)						
Natural gas	$16.0	$6.3	154.0 %	$28.5	$13.2	115.9 %
Crude oil	0.2	(4.5)	(104.4)%	(2.4)	(7.6)	(68.4)%
Total realized gain on derivatives, net	$16.2	$1.8	*	$26.1	$5.6	*
Average sales price (excluding gain/loss on derivatives)						
Natural gas (per Mcf)	$1.56	$3.54	(55.9)%	$1.83	$3.29	(44.4)%
Crude oil (per Bbl)	87.98	94.35	(6.8)%	90.54	92.15	(1.7)%
NGLs (per Bbl)	26.66	34.06	(21.7)%	27.45	39.41	(30.3)%
Natural gas equivalent (per Mcfe)	4.93	6.29	(21.6)%	5.37	5.95	(9.7)%
Average sales price (including gain/loss on derivatives)						
Natural gas (per Mcf)	$3.63	$4.39	(17.3)%	$3.61	$4.17	(13.4)%
Crude oil (per Bbl)	88.50	82.11	7.8 %	88.17	81.10	8.7 %
NGLs (per Bbl)	26.66	34.06	(21.7)%	27.45	39.41	(30.3)%
Natural gas equivalent (per Mcfe)	6.33	6.47	(2.2)%	6.43	6.22	3.4 %
Average lifting cost (per Mcfe) (4)	$1.03	$0.98	5.1 %	$0.95	$1.02	(6.9)%
Natural gas marketing (5)	$0.2	$0.7	(71.4)%	$0.5	$0.9	(44.4)%
Other costs and expenses						
Exploration expense	$2.6	$1.2	111.5 %	$4.6	$2.9	58.6 %
General and administrative expense	14.4	19.5	(26.3)%	29.1	33.4	(12.9)%

Depreciation, depletion and amortization	34.4	30.6	12.6 %	74.3	61.6	20.6 %
Interest expense	$10.1	$9.1	10.9 %	$20.5	$18.1	13.3 %

* Percentage change is not meaningful or equal to or greater than 300%.
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 our 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.

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(5) Represents sales from natural gas marketing, net of costs of natural gas marketing, including realized and unrealized derivative gains and losses related to natural gas marketing activities.

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 June 30,			Six Months Ended June 30,		
Production	2012	2011	Percentage Change	2012	2011	Percentage Change
Natural gas (MMcf)						
Western	6,208.0	6,151.2	0.9 %	13,088.2	12,938.7	1.2 %
Eastern	1,462.9	1,250.2	17.0 %	2,948.4	2,117.1	39.3 %
Other	5.0	9.8	(49.0)%	13.4	21.6	(38.0)%
Total	7,675.9	7,411.2	3.6 %	16,050.0	15,077.4	6.5 %
Crude oil (MBbls)						
Western	449.2	368.4	21.9 %	1,002.0	688.4	45.6 %
Eastern	2.8	1.6	75.0 %	5.2	2.7	92.6 %
Other	—	0.1	(100.0)%	—	0.2	(100.0)%
Total	452.0	370.1	22.1 %	1,007.2	691.3	45.7 %
NGLs (MBbls)						
Western	191.6	134.4	42.6 %	418.8	281.9	48.6 %
Other	0.9	1.9	(52.6)%	2.5	3.2	(21.9)%
Total	192.5	136.3	41.2 %	421.3	285.1	47.8 %
Natural gas equivalent (MMcfe)						
Western	10,054.2	9,168.4	9.7 %	21,613.2	18,760.4	15.2 %
Eastern	1,479.6	1,259.8	17.4 %	2,979.4	2,133.5	39.6 %
Other	9.7	21.8	(55.5)%	28.7	42.0	(31.7)%
Total	11,543.5	10,450.0	10.5 %	24,621.3	20,935.9	17.6 %

Amounts may not recalculate due to rounding.

Average Sales Price (excluding gain/loss on derivatives)	Three Months Ended June 30, 2012	2011	Percentage Change	Six Months Ended June 30, 2012	2011	Percentage Change
Natural gas (per Mcf) (1)						
Western	$1.44	$3.31	(56.5)%	$1.74	$3.11	(44.1)%
Eastern	2.06	4.62	(55.4)%	2.25	4.41	(49.0)%
Other	2.03	5.00	(59.4)%	2.55	3.67	(30.5)%
Weighted-average price	1.56	3.54	(55.9)%	1.83	3.29	(44.4)%
Crude oil (per Bbl)						
Western	$88.11	$94.39	(6.7)%	$90.52	$92.20	(1.8)%
Eastern	67.39	83.80	(19.6)%	82.75	80.56	2.7%
Other	—	101.41	(100.0)%	—	93.19	(100.0)%
Weighted-average price	87.98	94.35	(6.8)%	90.54	92.15	(1.7)%
NGLs (per Bbl)						
Western	$26.65	$33.99	(21.6)%	$27.39	$39.28	(30.3)%
Other	29.14	38.55	(24.4)%	38.35	51.13	(25.0)%
Weighted-average price	26.66	34.06	(21.7)%	27.45	39.41	(30.3)%
Natural gas equivalent (per Mcfe)						
Western	$5.34	$6.51	(18.0)%	$5.78	$6.12	(5.6)%
Eastern	2.16	4.70	(54.0)%	2.37	4.48	(47.1)%
Other	3.48	6.05	(42.5)%	6.51	6.21	4.8%
Weighted-average price	4.93	6.29	(21.6)%	5.37	5.95	(9.7)%

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 and six months ended 2012, natural gas, NGL and crude oil sales revenue decreased compared to the three months ended 2011 and increased compared to the six months ended 2011 due to the following:

	June 30, 2012 Three Months Ended (in millions)	Six Months Ended
Increase in crude oil production	$7.7	$29.1
Increase in natural gas production	0.9	3.2
Increase in NGL production	1.9	5.3
Decrease in average natural gas price	(15.1)	(23.4)
Decrease in average crude oil price	(2.9)	(1.6)
Decrease in average NGL price	(1.4)	(5.0)
Total increase (decrease) in natural gas, NGL and crude oil sales revenue	$(8.9)	$7.6

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 Colorado Interstate Gas ("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 based on New York Mercantile Exchange ("NYMEX") prices. This negative differential has narrowed over the last few years and is lower than historical variances. The negative differential between NYMEX and CIG averaged $0.19 and $0.31 for six 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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Lease operating expenses	$11.9	$10.3	$23.4	$21.4
Production taxes	3.9	4.1	8.9	8.2
Cost of well operations, overhead and other production expenses	3.1	2.5	5.8	5.8
Total production costs	$18.9	$16.9	$38.1	$35.4
Total production costs per Mcfe	$1.64	$1.62	$1.55	$1.69

Lease operating expenses. Quarter-over-quarter, the increase in lease operating expenses, or lifting costs, was primarily due
to the 10.5% increase in production and $0.7 million increase in wages, related benefits and other expenses primarily associated with our Seneca Upshur acquisition, offset in part by a decrease of $0.8 million in environmental expenses. Year-over-year, the increase in lifting costs was primarily related to the 17.6% increase in production and a $1.4 million increase in wages, related benefits and other expenses primarily associated with our Seneca Upshur acquisition, offset in part by decreases of $1.5 million in well workover expense and $2.4 million in environmental expenses. On a per Mcfe basis, lifting costs increased 5.1% quarter-over-quarter compared to a year-over-year decrease of 6.9%.

Production taxes. Production taxes are directly related to natural gas, NGL and crude oil sales. The $0.2 million, or 4.9%, decrease in production taxes for the three months ended 2012 compared to the three months ended 2011, was primarily related to the 13.5% decrease in natural gas, NGL and crude oil sales. Similarly, the $0.7 million, or 8.5%, increase in production taxes for the six months ended 2012 compared to the six months ended 2011 was primarily related to the 6.1% 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 June 30, 2012.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Commodity price risk management gain (losses), net:				
Realized gains (losses):				
Natural gas	$16.0	$6.3	$28.5	$13.2
Crude oil	0.2	(4.5)	(2.4)	(7.6)
Total realized gains, net	16.2	1.8	26.1	5.6
Unrealized gains (losses):				
Unrealized gains (losses) for the period	36.0	19.5	40.1	(2.3)
Reclassification of realized gains included in prior periods unrealized	(13.5)	(0.8)	(16.0)	(6.6)
Total unrealized gains (losses), net	22.5	18.7	24.1	(8.9)
Total commodity price risk management gain (loss), net	$38.7	$20.5	$50.2	$(3.3)

Realized gains recognized in the three and six 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 and six months ended 2012, realized gains on natural gas, exclusive of basis swaps, were $20.1 million and $37.1 million, respectively. These gains were reflective of a weighted-average strike price of $5.64 and $5.81, respectively, compared to a weighted-average settlement price of $2.22 and $2.46, respectively. These gains were offset in part by realized losses of $4.1 million and $8.6 million, respectively, on our basis swap positions as the negative basis differential between NYMEX and CIG was a weighted-average of $0.27 and $0.19, respectively, compared to a weighted-average strike price of $1.82 and $1.83, respectively.
Realized gains for the three months ended 2012 on our crude oil positions are reflective of a weighted-average strike price of $93.72 compared to a weighted-average settlement price of $92.93. Realized losses for the six months ended 2012 on our crude oil positions are reflective of a weighted-average strike price of $91.68 compared to a weighted-average settlement price of $97.58.

During the three months ended 2012, unrealized gains on our crude oil positions were $40.6 million due to the downward shift in the crude oil forward curve. These gains were offset slightly by unrealized losses on our natural gas positions of $4.1 million, resulting from the upward shift in the natural gas forward curve and unrealized losses on our CIG basis swaps of $0.5 million due to the narrowing of the CIG basis forward curve.
Unrealized gains during the six months ended 2012 were primarily related to a downward shift in the natural gas and crude oil forward curves and their impact on the fair value of our open positions. For the six month period, unrealized gains on our natural gas and crude oil derivative positions were $11.5 million and $29.4 million, respectively, offset in part by a narrowing of the CIG basis forward curve resulting in an unrealized loss of $0.8 million.
During the three and six months ended 2011, realized gains on natural gas derivatives, exclusive of basis swaps, were $10.2 million and $19.3 million, respectively. These gains were offset in part by realized losses of $3.9 million and $6.1 million, respectively, on our basis swap positions as the negative basis differential between NYMEX and CIG was narrower than the strike price of the basis positions. For the three and six months ended 2011, the realized losses on our crude oil positions were due to higher spot prices at settlement compared to the respective strike price.

Unrealized gains during the three months ended 2011 were primarily related to a downward shift in the natural gas and crude oil forward curves and their impact on the fair value of our open positions. For the three months ended 2011, unrealized gains on our natural gas and crude oil positions were $7.5 million and $12.7 million, respectively, offset slightly by the narrowing of the CIG basis forward curve, which resulted in an unrealized loss of $0.7 million. For the six month period, the shift upward in the crude oil forward curve and the narrowing of the CIG basis forward curve resulted in unrealized losses of $5.8 million and $1.9 million, respectively. The shift downward in the natural gas forward curve resulted in an unrealized gain of $5.4 million.

Natural Gas Marketing

Fluctuations in our natural gas marketing income 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.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Sales from natural gas marketing				
Natural gas sales revenue	$9.4	$18.4	$20.3	$33.5
Realized derivative gain	0.7	0.5	1.5	1.6
Unrealized derivative gain (loss)	(1.1)	—	(1.0)	(1.0)
Total sales from natural gas marketing	9.0	18.9	20.8	34.1
Cost of natural gas marketing				
Cost of natural gas purchases	8.8	17.5	19.1	32.1
Realized derivative loss	0.7	0.4	1.5	1.4
Unrealized derivative loss (gain)	(1.1)	0.1	(1.0)	(0.8)
Other	0.4	0.2	0.7	0.5
Total cost of natural gas marketing	8.8	18.2	20.3	33.2
Natural gas marketing contribution margin	$0.2	$0.7	$0.5	$0.9

The quarter-over-quarter and year-over-year decrease in natural gas sales revenue and costs of natural gas purchases is primarily attributable to lower average prices and, to a much lesser extent, a decrease in volumes. Quarter-over-quarter, decreases in natural gas sales revenue and costs of natural gas purchases were primarily attributable to a 50.7% decrease in average natural gas sales price and a 50.5% decrease in the average natural gas purchase price. Similarly, year-over-year decreases in natural gas sales revenue and costs of natural gas purchases were primarily attributable to a 44.4% decrease in the average natural gas sales price and a 45.2% decrease in the average natural gas purchase price.

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.

Exploration Expense

The following table presents the major components of exploration expense:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Exploratory dry hole costs	$0.4	$0.1	0.4	0.2
Geological and geophysical costs	0.7	—	1.6	0.9
Operating, personnel and other	1.5	1.1	2.6	1.8
Total exploration expense	$2.6	$1.2	4.6	2.9

Exploratory dry hole costs. The quarter-over-quarter and year-over-year increases of $0.3 million and $0.2 million, respectively, are related to the unsuccessful testing of an exploratory zone in two existing Wattenberg Field wells.

Geological and geophysical costs. The quarter-over-quarter and year-over-year increases of $0.7 million, respectively, are primarily related to costs associated with an increase in our proportionate share of PDCM's geological and seismic testing of the Marcellus play in the

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Appalachian Basin and reservoir studies in the Utica Shale.

Operating, personnel and other. The quarter-over-quarter and year-over-year increases of $0.4 million and $0.8 million, respectively, in operating, personnel and other are mainly attributable to the increased payroll and employee benefits in the exploration division as a result of an increase in employee headcount.

General and Administrative Expense

General and administrative expense decreased $5.1 million, or 26.1%, to $14.4 million for the three months ended 2012 compared to $19.5 million for the three months ended 2011. The decrease is mainly attributable to $6.7 million incurred during the three months ended 2011 related to a separation agreement with our former chief executive officer, offset in part by increases in payroll and employee benefits of $1.4 million during the three months ended 2012.

General and administrative expense decreased $4.3 million, or 12.9%, to $29.1 million for the six months ended 2012 compared to $33.4 million for the six months ended 2011. The decrease is mainly attributable to $6.7 million incurred during the six months ended 2011 related to the separation agreement with our former chief executive officer and a decrease in legal and other professional fees of $2.4 million, offset in part by increases in payroll and employee benefits of $3.3 million and increased acquisition transaction costs of $1.1 million during the six months ended 2012.

Depreciation, Depletion and Amortization

Natural gas and crude oil properties. Depreciation, depletion and amortization expense related to natural gas and crude oil properties was $32.6 million and $70.6 million for the three and six months ended 2012 compared to $28.9 million and $58.1 million for the three and six months ended 2011. The increase in our production for the three and six months ended 2012 contributed $3.0 million and $10.2 million to these increases, respectively, while higher weighted-average depreciation, depletion and amortization rates resulted in an increase in depreciation, depletion and amortization expense of $0.7 million and $2.3 million for each of the three and six months ended 2012, respectively.

The following table presents our depreciation, depletion and amortization rates for natural gas and crude oil properties by operating region:

	Three Months Ended June 30,		Six Months Ended June 30,	
Operating Region/Area	2012	2011	2012	2011
	(per Mcfe)			
Western				
Wattenberg Field	$3.33	$3.38	$3.39	$3.32
Piceance Basin	2.74	2.48	2.77	2.51
Weighted-average	2.94	2.88	3.00	2.85
Eastern	2.05	1.97	1.91	2.20
Total weighted-average	2.82	2.76	2.87	2.78

Non-natural gas and crude oil properties. Depreciation expense for non-natural gas and crude oil properties was $1.8 million and $3.7 million for the three and six months ended 2012 compared to $1.7 million and $3.4 million for the three and six months ended 2011.

Gain on Sale of Properties and Equipment

The $2.2 million quarter-over-quarter increase and $2.4 million year-over-year increase in the gain on sale of properties and equipment mainly relates to our proportionate share of the gain realized from the sale by PDCM of certain leases in our Eastern Operating Region.

Non-Operating Income/Expense

Interest Expense. The increase in interest expense for the three and six months ended 2012 of $1 million and $2.4 million, respectively, compared to the three and six months ended 2011 is primarily related to increased borrowings on our corporate credit facility during 2012 compared to 2011. The lower 2011 average outstanding balance followed the November 2010 convertible debt and common stock offerings, the proceeds of which were used to pay down outstanding amounts under the credit facility.

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PDC ENERGY, INC.

Provision for Income Taxes

See Note 6, Income Taxes, to the accompanying condensed consolidated financial statements for a discussion of the changes in our effective tax rate quarter-over-quarter and year-over-year. Due to tax interim period benefit limitations, comparisons of interim loss periods with interim income periods, and the different effects of permanent tax adjustments, primarily percentage depletion, the effective tax rate comparison for the three- and six-month periods is less meaningful. We have accepted an offer for continued participation in the IRS CAP program for our 2012 tax year.

Discontinued Operations

See Note 13, 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, consisting of producing wells and undeveloped leaseholds, to an unrelated third-party for a pretax gain of $3.9 million. In December 2011, we executed a purchase and sale agreement with COG, a wholly owned subsidiary of Concho Resources Inc., an unrelated third-party, for the sale of our then remaining Permian Basin assets and closed the transaction in February 2012. Upon final settlement on June 29, 2012, total proceeds received were $189.2 million after final closing adjustments, resulting in a pretax gain on sale of $19.9 million.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
Discontinued Operations	2012	2011	2012	2011
Production				
Natural gas (MMcf)	—	101.8	40.3	191.6
Crude oil (MBbls)	—	56.7	39.2	110.7
NGLs (per Bbl)	—	13.4	13.0	31.5
Natural gas equivalent (MMcfe)	—	522.2	353.1	1,044.9

Net Income/Adjusted Net Income (Loss)

Net income for the three and six months ended 2012 was $12.3 million and $28.1 million, respectively, compared to net income of $9.2 million and a net loss of $10.8 million for the three and six months ended 2011, respectively. Adjusted net loss, a non-U.S. GAAP financial measure, for the three months ended 2012 was $1.7 million and adjusted net income was $13.2 million for the six months ended 2012, compared to adjusted net loss of $2.4 million and $5.2 million for the three and six months ended 2011, respectively. The quarter-over-quarter changes in net income are discussed above, with the most significant changes being related to the decrease in natural gas, NGL and crude oil sales, and an increase in commodity price risk management activities. The year-over-year change in net income (loss) are discussed above, with the most significant changes being related to an increase in commodity price risk management activities, income from discontinued operations and a decrease in depreciation, depletion and amortization expense. These same reasons for change similarly impacted adjusted net income (loss), with the exception of the unrealized derivative gains and losses, 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

Historically, our primary sources of liquidity have been cash flows from operating activities, our credit facility, utilization of the debt and equity markets and asset monetization transactions. For the six months ended 2012, our primary sources of liquidity were the sale of our Permian assets for $189.2 million, proceeds from the issuance of our common stock of $164 million and net cash flow from operating activities of $69.7 million.

Our primary source of cash flows from 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 later 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 from 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 June 30, 2012, we had a working capital deficit of $28.2 million compared to a deficit of $22 million at December 31, 2011.

We ended June 2012 with cash and cash equivalents of $6 million and availability under our credit facility of $255.3 million, for a total liquidity position of $261.3 million compared to $196.4 million at December 31, 2011. The increase in liquidity of $64.8 million, or 33.0%, was primarily due to $189.2 million received from the divestiture of our Permian assets in February 2012, proceeds from issuance of common stock of $164 million in May 2012, an increase in the borrowing base of our credit facility of $125 million and cash flows from operating activities of $69.7 million, offset by $326.8 million related to the Merit Acquisition and capital expenditures of $165.2 million during the six months ended 2012. With our current liquidity position and expected cash flows from operations, we believe that we have sufficient capital to fund operations. We continue to execute our strategy of pursuing strategic and complementary acquisitions of developed and undeveloped properties in the Niobrara formation in our Western Operating Region and the emerging Utica Shale play in 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 annually based on our development and exploration opportunities, liquidity position and the expected cash flows from operating activities for that year. We may revise our capital budget during the year as a result of, among other things, acquisitions or 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 the Merit Acquisition, we are slightly increasing our development capital budget to $186 million, our exploratory capital budget to $95 million and other capital budget to $7 million, for a total of $288 million, excluding acquisition costs. Of our $186 million for developmental drilling, which includes recompletions and refractures, substantially all will be invested in the Wattenberg field. During the six months ended 2012, we drilled 13 horizontal wells in the Wattenberg Field, of which eight were completed and turned-in-line, and executed 103 refractures/recompletions projects on 55 wells. PDCM's 2012 capital budget is currently set at $54 million, of which $27 million represents our share, and is expected to be funded by PDCM's operating activities, its credit facility, the sale of various leases and funds received related to title defects discovered from its acquisition of Seneca-Upshur. During the six months ended 2012, PDCM drilled, completed and turned-in-line three horizontal Marcellus wells and has three wells drilled in 2011 currently awaiting completion. We believe, based on the current commodity price environment, with our extensive derivative program and our estimated 2012 production of approximately 51.5 Bcfe, our cash flows from operating activities, proceeds from our issuance of common stock and the sale of our Permian assets will fund our current 2012 capital budget, including our Merit Acquisition, 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, we need to continue to commit significant amounts of capital in 2012 and beyond in order to grow our production. 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 from operating activities if capital markets and commodity prices were to become depressed and/or the borrowing base under 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 under our corporate credit facility. Our credit facility borrowing base, recently increased to $525 million following the Merit Acquisition, is subject to size redeterminations each May and November based upon a quantification of our proved reserves at each June 30 and December 31 respectively. A commodity price deck reflective of the current and future commodity pricing environment is utilized by our lenders to quantify our reserve reports and determine the underlying borrowing base. Our next scheduled redetermination is in November 2012. While we have continued to add producing reserves through an acquisition and 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 an automatic shelf registration statement on Form S-3 with the SEC. 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. Pursuant to this shelf registration, we sold 6.5 million shares of our common stock in May, 2012 in underwritten public offering at a price to the public of $26.50 per share. We used the net proceeds of $164 million to pay off the outstanding balance on our credit facility and for general corporate purposes.

We are subject to quarterly financial debt covenants on our credit facility. Currently, our key credit facility debt covenants require that we maintain: (i) total debt of less than 4.0 times earnings before interest, taxes, depreciation, depletion and amortization expense and capital expenditures ("EBITDAX") and (ii) an adjusted working capital ratio of at least 1.0 to 1.0. Our adjusted working capital ratio is calculated by reducing our current assets and liabilities by any impact of recording the fair value of our natural gas and crude oil derivative instruments and adding our available borrowings on our corporate 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 related to our credit facility at June 30, 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: (i) EBITDAX of at least two times interest expense and (ii) total debt of less than 4.0 times EBITDAX. We were in compliance with all covenants related to our senior notes at June 30, 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 from 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 from operating activities decreased slightly by $1.9 million for the six months ended 2012 compared to the same period in 2011. The slight decrease was primarily the result of the $20.4 million decrease in net assets due to the timing of cash payments and receipts, offset in part by the $20.5 million increase in net realized derivative gains. See Results of Operations above for an additional discussion of the key drivers of cash flows from operating activities.

Adjusted cash flows from operations and adjusted EBITDA increased $18.5 million and $41.9 million, respectively, for the six months ended 2012 compared to the same period in 2011. These increases were primarily due to the increase in net realized gains mentioned above without regard to timing of cash payments and receipts related to our assets and liabilities, and in the case of adjusted EBITDA the increase in the gain from 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 from investing activities of $292.6 million during the six months ended 2012 was primarily related to the $326.8 million expended in June 2012 for the Merit Acquisition and drilling activity of $165.2 million, offset in part by $189.2 million received from the divestiture of our Permian assets in February 2012 and $24 million received related to title defects discovered from PDCM's Seneca Upshur acquisition in October 2011, of which $12 million represents our share. Our drilling program currently consists of two rigs operating in the oil- and liquids-rich horizontal Niobrara play in our Wattenberg Field and an additional rig in the emerging Utica shale play to support our exploratory efforts there.

Financing Activities. Cash flows from financing activities for the six months ended 2012 increased significantly compared to the same period in 2011, from $20.6 million to $220.7 million. The increase is primarily related to the $164 million received from the sale of our common stock and a draw on our corporate credit facility to fund the June 2012 Merit Acquisition.

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.

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PDC ENERGY, INC.

Net Drilling Activity

	Three Months Ended June 30,				Six Months Ended June 30,			
	2012		2011		2012		2011	
Operating Region/Area	Productive	In-Process (1)	Productive	In-Process	Productive	In-Process (1)	Productive	In-Process
Development Wells								
Western								
Wattenberg Field	1.4	4.4	3.8	24.7	6.1	5.6	31.1	25.9
Piceance Basin	—	—	—	6.0	—	—	2.0	10.0
Total Western	1.4	4.4	3.8	30.7	6.1	5.6	33.1	35.9
Eastern	—	—	—	2.1	1.5	—	—	2.1
Total development wells	1.4	4.4	3.8	32.8	7.6	5.6	33.1	38.0
Exploratory Wells								
Western	—	—	—	—	—	—	—	1.0
Eastern	—	2.0	—	—	—	2.0	—	—
Total exploratory wells	—	2.0	—	—	—	2.0	—	1.0
Total drilling activity	1.4	6.4	3.8	32.8	7.6	7.6	33.1	39.0

(1) A total of 13.9 net wells, including the 7.6 net wells drilled during the six months ended 2012 and still in-process as of June 30, 2012, 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 Form 10-K. There have been no material changes to our contractual obligations from December 31, 2011. See Note 9, Commitments and Contingencies, to the accompanying condensed consolidated financial statements included in this report 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 consolidated 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 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 included in this report.

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

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consider adjusted net income (loss) as well as net income (loss). 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) 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 many of our peers.

The following table presents a reconciliation of our non-U.S. GAAP financial measures to its most comparable U.S. GAAP measure:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Adjusted cash flows from operations:				
Adjusted cash flows from operations	$29.2	$34.1	$78.7	$60.2
Changes in assets and liabilities	(3.8)	22.0	(9.0)	11.4
Net cash from operating activities	$25.4	$56.1	$69.7	$71.6
Adjusted net income (loss):				
Adjusted net income (loss)	$(1.7)	$(2.4)	$13.2	$(5.2)
Unrealized gain on derivatives, net	22.6	18.7	24.1	(9.1)
Tax effect of above adjustments	(8.6)	(7.1)	(9.2)	3.5
Net income (loss)	$12.3	$9.2	$28.1	$(10.8)
Adjusted EBITDA:				
Adjusted EBITDA	$40.7	$36.2	$115.4	$73.5
Unrealized gain (loss) on derivatives, net	22.6	18.7	24.1	(9.1)
Interest expense, net	(10.1)	(9.1)	(20.5)	(18.1)
Income tax provision	(6.1)	(3.4)	(15.6)	8.9
Impairment of natural gas and crude oil properties	(0.3)	(0.5)	(1.0)	(1.0)
Depreciation, depletion and amortization	(34.5)	(32.7)	(74.3)	(65.0)
Net income (loss)	$12.3	$9.2	$28.1	$(10.8)

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, asset impairments, 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 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 June 30, 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 June 30, 2012, was $10.8 million and represents our aggregate bank balances, including checks issued and outstanding. Based on a sensitivity analysis of our interest-bearing deposits as of June 30, 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 June 30, 2012, excluding the $18.7 million irrevocable standby letters of credit, we had outstanding borrowings on our corporate credit facility of $265 million and, representing our proportionate share, $26.0 million on PDCM's credit facility. We estimate that if market interest rates were to increase or decrease by 1%, our 2012 interest expense would change by approximately $1.5 million.

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 $306.5 million at June 30, 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 June 30, 2012:

	Floors		Collars			Fixed-Price Swaps		CIG Basis Protection Swaps		
Commodity/ Index/ Maturity Period	Quantity (Gas - BBtu (1))	Weighted-Average Contract Price	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted-Average Contract Price Floors	Ceilings	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted-Average Contract Price	Quantity (BBtu) (1)	Weighted-Average Contract Price	Fair Value as of June 30, 2012 (2)(in millions)
Natural Gas										
NYMEX										
2012	2,380.0	$ 6.00	—	$—	$—	11,466.3	$ 4.79	5,079.3	$ (1.81)	$20.1
2013	4,910.0	6.20	—	—	—	22,340.2	4.66	9,384.4	(1.81)	22.4
2014	—	—	—	—	—	13,390.0	4.03	—	—	1.1
2015	—	—	—	—	—	7,800.0	3.84	—	—	(2.1)
2016	—	—	—	—	—	7,200.0	3.84	—	—	(3.0)
CIG										
2012	—	—	—	—	—	405.0	4.11	—	—	0.5
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	—	—	—	—	0.8
PEPL										
2012	—	—	—	—	—	653.0	6.18	—	—	2.2
2013	—	—	—	—	—	990.4	6.18	—	—	2.8
Total Natural Gas	7,290.0		2,390			64,244.9		14,463.7		46.1
Crude Oil										
NYMEX										
2012	—	—	403.8	83.43	108.03	438.0	93.77	—	—	5.0
2013	—	—	1,105.6	80.46	103.58	1,220.9	97.36	—	—	13.7
2014	—	—	652.0	84.49	103.46	50.0	102.7	—	—	3.7
2015	—	—	36.0	90.00	106.15	—	—	—	—	0.3
Total Crude Oil	—		2,197.4			1,708.9		—		22.7
Total Natural Gas and Crude Oil										$68.8

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

(2) Approximately 29.9% of the fair value of our derivative assets and 0.27% 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:

	Six Months Ended June 30, 2012	Year Ended December 31, 2011
Average Index Closing Price:		
Natural Gas (per MMBtu)		
CIG	$2.29	$3.79
NYMEX	2.48	4.04
Crude Oil (per Bbl)		
NYMEX	100.31	94.01
Average Sales Price Realized:		
Excluding realized derivative gains/(losses)		
Natural Gas (per Mcf)	$1.56	$3.27
Crude Oil (per Bbl)	87.98	87.63
Including realized derivative gains/(losses)		
Natural Gas (per Mcf)	3.63	4.23
Crude Oil (per Bbl)	88.50	80.69

Based on a sensitivity analysis as of June 30, 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 $54.0 million, while a 10% decrease in prices would have resulted in an increase in fair value of $54.2 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 $53.1 million and an increase in fair value of $53.3 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 June 30, 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. Regarding our Gas Marketing segment, our receivables are from a diverse group of entities, 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, though we cannot be assured that will always be the case.

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 potential impact of nonperformance of our counterparties on the fair value of our derivative instruments was not significant. 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.

Disclosure of Limitations

Because the information above included only those exposures that existed at June 30, 2012, it does not consider those exposures or positions which could arise subsequent to that date. As a result, our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend upon 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 June 30, 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 June 30, 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 and the corresponding section of our Quarterly Report on Form 10-Q for the three months ended March 31, 2012 (the "First Quarter 10-Q"). 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, as supplemented by the risk factor disclosures set forth in the First Quarter 10-Q, which are incorporated by reference herein, except for the following:
Risks Related to Our Business and the Industry

The marketability of our production is dependent upon limited transportation and processing facilities over which we may have no control. Market conditions or operational impediments, including transportation and gathering systems, could hinder our access to natural gas and crude oil markets or delay production and thereby adversely affect our profitability.

Our ability to market our production depends in substantial part on the availability, proximity and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. If adequate gathering, processing and transportation facilities are not available to us on a timely basis and at acceptable costs, our production and results of operations will be adversely affected. For example, due to increased drilling activities by third parties and unusually hot temperatures in Colorado, the principal third-party provider we use in the Wattenberg area for these facilities and services has recently experienced high line pressure, and the resulting capacity constraints have impacted productivity of some of our older wells and limited the incremental production impact of our new horizontal wells. As a result, we have seen an impact on our production and a related decrease in revenue from the impacted wells. Thus, our profitability has been adversely affected, and will continue to be affected until available capacity increases or alternative arrangements are available. Additional pipelines and facilities are being planned for the area but are not expected to be completed until the latter part of 2013. Capacity constraints affecting natural gas production also impact our ability to produce the associated NGLs. We face similar risks in our other operating areas, and those risks are likely to be greater in areas, such as the Utica Shale, where other companies have announced plans to expand their drilling operations.

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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
April 1 - 30, 2012	5,508	$32.42	—	—
May 1 - 31, 2012	16,182	35.14	—	—
June 1 - 30, 2012	39	24.52	—	—
Total	21,729	34.43		

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(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

ITEM 6. EXHIBITS

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
3.1	Third Amended and Restated Articles of Incorporation of PDC Energy, Inc.					X
3.2	Bylaws of PDC Energy, Inc.					X
10.1	Fourth Amendment to the Second Amended and Restated Credit Agreement dated as of June 25, 2012, by and among the Company as Borrower, certain of its Subsidiaries as Guarantors, JPMorgan Chase Bank, N.A. as Administrative Agent, and various other banks as Lenders.	8-K	000-07246	99.1	07/02/2012	
10.2	Fifth Amendment to the Second Amended and Restated Credit Agreement dated as of June 29, 2012, by and among the Company as Borrower, certain of its Subsidiaries as Guarantors, JPMorgan Chase Bank, N.A. as Administrative Agent, and various other banks as Lenders.	8-K	000-07246	10.1	07/02/2012	
10.3	Underwriting Agreement, by and among Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC and Wells Fargo Securities, LLC, as representatives of the underwriters named therein, and PDC Energy, Inc., dated as of May 15, 2012.	8-K	000-07246	1.1	05/16/2012	
10.4	Purchase Agreement by and among Merit Management Partners I, L.P., Merit Energy Partners III, L.P., Merit Energy Partners D-III, L.P. and PDC Energy, Inc., dated as of May 11, 2012.	8-K	000-07246	10.1	5/14/2012	
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					X

	the Sarbanes-Oxley Act of 2002.
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.

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PDC ENERGY, INC.

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.

PDC Energy, Inc.
(Registrant)

Date: August 2, 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)