PDC ENERGY, INC.
Form 10-Q
August 01, 2013
Table of contents

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, 2013

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

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

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

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

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

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

Large accelerated filer x	Accelerated filer o

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: 30,456,472 shares of the Company's Common Stock ($0.01 par value) were outstanding as of July 19, 2013.

Table of contents

PDC ENERGY, INC.

TABLE OF CONTENTS

Table of contents

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 reserves; future production (including the components of such production), expenses, cash flows and liquidity; that our evaluation method is appropriate and consistent with those used by other market participants; anticipated capital projects, expenditures and opportunities; future exploration, drilling and development activities; our Wattenberg and Utica drilling programs; availability of additional midstream facilities and services, the timing of that availability and related benefits to us; availability of sufficient funding for our 2013 capital program and sources of that funding, including our partnership repurchase obligation and potential sale of our shallow upper Devonian (non-Marcellus Shale) Appalachian basin properties; the impact of high line pressures and the expected impact of the LaSalle plant; our compliance with debt covenants; potential future transactions; the borrowing base under our credit facility; effectiveness of our derivative program in providing a degree of price stability; 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, crude oil, natural gas and NGLs, 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 crude oil, natural gas and NGLs;
- the impact of governmental policies and/or regulations, including changes in environmental and other laws, the interpretation and enforcement related to those laws and regulations, liabilities arising thereunder and the costs to comply with those laws and regulations;
- potential declines in the value of our crude oil and natural gas properties resulting in impairments;
- changes in estimates of proved reserves;
- inaccuracy of reserve estimates and expected production rates;
- potential for production decline rates from our wells to be greater than expected;
- 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;
- timing of the connection of our Utica Basin wells to gathering, processing, fractionation and transportation infrastructure;
- timing and receipt of necessary regulatory permits;
- risks incidental to the drilling and operation of crude oil and natural gas wells;
- our future cash flows, liquidity and financial condition;
- competition in the oil and gas industry;
- availability and cost of capital;

- reductions in the borrowing base under our revolving credit facility;
- availability of sufficient pipeline, gathering and other transportation facilities and related infrastructure to process and transport our production, particularly in the Wattenberg Field, and the impact of these facilities on the prices we receive for our production;
- our success in marketing crude oil, natural gas and NGLs;
- effect of crude oil and natural gas derivatives activities;
- impact of environmental events, governmental and other third-party responses to such events, and our ability to insure adequately against such events;
- cost of pending or future litigation;
- effect that acquisitions we may pursue have on our capital expenditures;
- purchase price or other adjustments relating to asset acquisitions or dispositions that may be unfavorable to us;
- our ability to retain or attract senior management and key technical employees; and
- success of strategic plans, expectations and objectives for our future operations.

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, 2012 ("2012 Form 10-K"), filed with the U.S. Securities and Exchange Commission ("SEC") on February 27, 2013 and in our Current Report on Form 8-K filed on June 28, 2013, 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 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 Energy," "PDC," "the Company," "we," "us," "our" or "ours" 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's ("PDCM"), a joint venture currently owned 50% each by PDC and Lime Rock Partners, LP, formed for the purpose of exploring and developing the Marcellus Shale formation in the Appalachian Basin. Unless the context otherwise requires, references in this report to "Appalachian Basin" refers to our operations in the Utica Shale in Ohio and Marcellus Shale in West Virginia and Pennsylvania, including 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 elsewhere in this report for a description of our consolidated subsidiaries.

Table of contents

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, 2013	December 31, 2012 (1)
Assets		
Current assets:		
Cash and cash equivalents	$43,212	$2,457
Restricted cash	3,949	3,942
Accounts receivable, net	73,947	64,880
Accounts receivable affiliates	14,814	4,842
Fair value of derivatives	16,287	52,042
Deferred income taxes	17,045	36,151
Prepaid expenses and other current assets	7,993	7,635
Total current assets	177,247	171,949
Properties and equipment, net	1,438,880	1,616,706
Assets held for sale	32,160	—
Fair value of derivatives	10,421	6,883
Other assets	32,727	31,310
Total Assets	$1,691,435	$1,826,848
Liabilities and Shareholders' Equity		
Liabilities		
Current liabilities:		
Accounts payable	$75,520	$82,716
Accounts payable affiliates	821	5,296
Production tax liability	25,228	25,899
Fair value of derivatives	5,702	18,439
Funds held for distribution	27,730	34,228
Accrued interest payable	8,825	11,056
Other accrued expenses	23,976	25,715
Total current liabilities	167,802	203,349
Long-term debt	639,127	676,579
Deferred income taxes	118,246	148,427
Asset retirement obligation	35,367	61,563
Fair value of derivatives	4,475	10,137
Liabilities held for sale	22,370	—
Other liabilities	15,920	23,612
Total liabilities	1,003,307	1,123,667
Commitments and contingent liabilities		
Shareholders' equity		
Preferred shares - par value $0.01 per share, 50,000,000 shares authorized, none issued	—	—
	304	303

Common shares - par value $0.01 per share, 100,000,000 authorized, 30,443,287 and 30,294,224 issued as of June 30, 2013 and December 31, 2012, respectively		
Additional paid-in capital	392,617	387,494
Retained earnings	296,068	315,568
Treasury shares - at cost, 18,141 and 5,059 as of June 30, 2013 and December 31, 2012, respectively	(861)	(184)
Total shareholders' equity	688,128	703,181
Total Liabilities and Shareholders' Equity	$1,691,435	$1,826,848

____
(1) Derived from our audited 2012 balance sheet.

See accompanying Notes to Condensed Consolidated Financial Statements
1

Table of contents

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,	
	2013	2012	2013	2012
Revenues:				
Crude oil, natural gas and NGLs sales	$77,537	$51,342	$156,976	$118,297
Sales from natural gas marketing	18,079	8,613	31,749	19,994
Commodity price risk management gain, net	24,724	38,729	2,369	50,230
Well operations, pipeline income and other	965	1,056	2,037	2,225
Total revenues	121,305	99,740	193,131	190,746
Costs, expenses and other:				
Production costs	16,176	12,373	32,034	25,309
Cost of natural gas marketing	18,065	8,490	31,801	19,581
Exploration expense	1,437	2,374	3,126	4,246
Impairment of crude oil and natural gas properties	1,502	356	47,961	944
General and administrative expense	15,783	14,378	30,898	29,086
Depreciation, depletion, and amortization	27,800	23,839	55,749	51,751
Accretion of asset retirement obligations	1,172	732	2,320	1,459
Gain on sale of properties and equipment	(9)	(2,246)	(47)	(2,400)
Total cost, expenses and other	81,926	60,296	203,842	129,976
Income (loss) from operations	39,379	39,444	(10,711)	60,770
Interest expense	(13,089)	(10,053)	(26,446)	(20,497)
Interest income	3	—	3	2
Income (loss) from continuing operations before income taxes	26,293	29,391	(37,154)	40,275
Provision for income taxes	(9,791)	(10,213)	12,701	(14,333)
Income (loss) from continuing operations	16,502	19,178	(24,453)	25,942
Income (loss) from discontinued operations, net of tax	3,416	(6,907)	4,953	2,164
Net income (loss)	$19,918	$12,271	$(19,500)	$28,106
Earnings per share:				
Basic				
Income (loss) from continuing operations	$0.55	$0.72	$(0.80)	$1.03
Income (loss) from discontinued operations	0.11	(0.26)	0.16	0.09
Net income (loss)	$0.66	$0.46	$(0.64)	$1.12
Diluted				
Income (loss) from continuing operations	$0.53	$0.72	$(0.80)	$1.03
Income (loss) from discontinued operations	0.11	(0.26)	0.16	0.08
Net income (loss)	$0.64	$0.46	$(0.64)	$1.11
Weighted-average common shares outstanding:				
Basic	30,332	26,597	30,301	25,103
Diluted	31,014	26,728	30,301	25,268

See accompanying Notes to Condensed Consolidated Financial Statements

Table of contents

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

	Six Months Ended June 30, 2013		2012	
Cash flows from operating activities:				
Net income (loss)	$(19,500	)	$28,106	
Adjustments to net income (loss) to reconcile to net cash from operating activities:				
Unrealized (gain) loss on derivatives, net	9,913		(24,079	)
Depreciation, depletion and amortization	58,007		74,262	
Impairment of crude oil and natural gas properties	47,964		1,023	
Accretion of asset retirement obligation	2,481		1,644	
Stock-based compensation	6,951		3,901	
Excess tax benefits from stock-based compensation	(930	)	(356	)
(Gain) loss on sale of properties and equipment	1,029		(22,331	)
Amortization of debt discount and issuance costs	3,419		3,547	
Deferred income taxes	(11,075	)	12,330	
Other	454		1,168	
Changes in assets and liabilities	(56,687	)	(9,520	)
Net cash from operating activities	42,026		69,695	
Cash flows from investing activities:				
Capital expenditures	(139,462	)	(165,157	)
Acquisition of oil and gas properties	—		(309,285	)
Proceeds from acquisition adjustments	7,579		11,969	
Proceeds from sale of properties and equipment	173,297		187,340	
Other	—		(17,497	)
Net cash from investing activities	41,414		(292,630	)
Cash flows from financing activities:				
Proceeds from revolving credit facility	227,750		483,250	
Payment of revolving credit facility	(267,000	)	(425,250	)
Proceeds from sale of common stock, net of issuance costs	—		164,050	
Payment of debt issuance costs	(1,961	)	(636	)
Excess tax benefits from stock-based compensation	930		356	
Purchase of treasury shares	(2,404	)	(1,117	)
Net cash from financing activities	(42,685	)	220,653	
Net change in cash and cash equivalents	40,755		(2,282	)
Cash and cash equivalents, beginning of period	2,457		8,238	
Cash and cash equivalents, end of period	$43,212		$5,956	
Supplemental cash flow information:				
Cash payments (receipts) for:				
Interest, net of capitalized interest	$25,787		$17,918	
Income taxes	(57	)	1,468	
Non-cash investing activities:				
Change in accounts payable related to purchases of properties and equipment	$(8,695	)	$(12,927	)
	211		11,934	

Change in asset retirement obligation, with a corresponding change to crude oil and natural gas properties, net of disposals		
Change in accounts payable related to disposition of properties and equipment	(4,680)	—
Change in accounts receivable affiliates related to disposition of properties and equipment	9,201	—

See accompanying Notes to Condensed Consolidated Financial Statements
3

Table of Contents
PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
JUNE 30, 2013
(Unaudited)

NOTE 1 - NATURE OF OPERATIONS AND BASIS OF PRESENTATION

PDC Energy, Inc. ("PDC," "PDC Energy," "we," "us" or "the Company") is a domestic independent crude oil, natural gas and NGL company engaged in the exploration for and the acquisition, development, production and marketing of crude oil, natural gas and NGLs. PDC is focused operationally on the liquid-rich Wattenberg Field in the DJ Basin and, in the Appalachian Basin, on the liquid-rich Utica Shale and the dry-gas Marcellus Shale. As of June 30, 2013, we owned an interest in approximately 6,200 gross wells. 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 presentation of our financial statements for interim periods in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, pursuant to such rules and regulations, certain notes and other financial information included in audited financial statements have been condensed or omitted. The information presented in this Quarterly Report on Form 10-Q should be read in conjunction with our audited consolidated financial statements and notes thereto included in our 2012 Form 10-K. Our results of operations and cash flows for the three and six months ended June 30, 2013 are not necessarily indicative of the results to be expected for the full year or any other future period.

Certain reclassifications have been made to prior period financial statements to conform to the current year presentation. The reclassifications are mainly attributable to reporting as discontinued operations the results of operations related to the sale of our Piceance Basin and Northeast Colorado ("NECO") oil and gas properties. See Note 12, Assets Held for Sale, Divestitures and Discontinued Operations, for additional information regarding the divestiture. We also reclassified accretion of asset retirement obligations out of the statement of operations line item production cost and into accretion of asset retirement obligations and reclassified prepaid well cost write-offs out of the statement of cash flows line item changes in assets and liabilities and into the line item other. These reclassifications had no impact on previously reported cash flows, net income, earnings per share or shareholders' equity.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Recently Adopted Accounting Standard

On January 1, 2013, we adopted changes issued by the Financial Accounting Standards Board regarding the disclosure of offsetting assets and liabilities. These changes require an entity to disclose both gross and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an enforceable master netting arrangement or similar agreement. The enhanced disclosures enable users of an entity's financial statements to understand and evaluate the effect or potential effect of master netting arrangements on an entity's financial position, including the effect or potential effect of rights of setoff associated with certain financial instruments and derivative instruments. Our adoption of these changes had no impact on the condensed consolidated financial statements, except for additional disclosures.

Recently Issued Accounting Standard

Income Taxes. On July 18, 2013, the FASB issued an update to accounting for income taxes. The update provides clarification on the presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss or a tax credit carryforward exists. The update is effective for public entities for fiscal years, and interim periods within those years, beginning after December 15, 2013. Early adoption is permitted. We have not yet evaluated the impact of the update on our financial statements.

NOTE 3 - FAIR VALUE OF FINANCIAL INSTRUMENTS

Derivative Financial Instruments

Determination of fair value. Our fair value measurements are estimated pursuant to a fair value hierarchy that requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. In these cases, 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.

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, crude oil and natural gas 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 revolving 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 is not significant.

Our fixed-price swaps, basis swaps and physical purchases are included in Level 2 and our crude oil and natural gas collars, natural gas calls 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, 2013			December 31, 2012		
	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 derivative contracts	$21,711	$4,338	$26,049	$42,788	$15,734	$58,522

Basis protection derivative contracts	642	17	659	387	16	403
Total assets	22,353	4,355	26,708	43,175	15,750	58,925
Liabilities:						
Commodity-based derivative contracts	7,497	451	7,948	9,839	2,081	11,920
Basis protection derivative contracts	2,229	—	2,229	16,656	—	16,656
Total liabilities	9,726	451	10,177	26,495	2,081	28,576
Net asset	$12,627	$3,904	$16,531	$16,680	$13,669	$30,349

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(in thousands)			
Fair value, net asset, beginning of period	$7,663	$19,644	$13,669	$22,107
Changes in fair value included in statement of operations line item:				
Commodity price risk management gain, net	2,834	13,737	103	15,153
Sales from natural gas marketing	22	(4)	6	39
Changes in fair value included in balance sheet line item:				
Accounts payable affiliates (1)	—	(94)	—	(146)
Settlements included in statement of operations line items:				
Commodity price risk management loss, net	(2,246)	(4,661)	(5,479)	(8,458)
Sales from natural gas marketing	(3)	(22)	(29)	(95)
Income from discontinued operations, net of tax	(4,366)	—	(4,366)	—
Fair value, net asset end of period	$3,904	$28,600	$3,904	$28,600
Changes in unrealized gains (losses) relating to assets (liabilities) still held as of year-end, included in statement of operations line item:				
Commodity price risk management gain, net	$(1,717)	$10,449	$(3,652)	$8,661
Sales from natural gas marketing	22	(13)	10	1
Total	$(1,695)	$10,436	$(3,642)	$8,662

____
(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.

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 portion of our long-term debt related to our revolving 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, 2013, 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 $160.5 million, or 139.6% of par value, and the portion related to our 7.75% senior notes due 2022 to be $519.7 million, or 103.9% 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 2 inputs.

Concentration of Risk

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 revolving credit facility as counterparties to our derivative contracts. To date, we have had no counterparty default losses relating to our derivative arrangements. 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 at June 30, 2013, taking into account the estimated likelihood of nonperformance.

Table of contents

The following table presents the counterparties that expose us to credit risk as of June 30, 2013 with regard to our derivative assets:

Counterparty Name	Fair Value of Derivative Assets As of June 30, 2013 (in thousands)
JPMorgan Chase Bank, N.A. (1)	$9,730
Wells Fargo Bank, N.A. (1)	3,671
Natixis (1)	2,924
Bank of Nova Scotia (1)	2,680
Other lenders in our revolving credit facility	6,754
Various (2)	949
Total	$26,708

____
(1)Major lender in our revolving credit facility. See Note 7, Long-Term Debt.
(2)Represents a total of 23 counterparties.

NOTE 4 - DERIVATIVE FINANCIAL INSTRUMENTS

Our results of operations and operating cash flows are affected by changes in market prices for crude oil, natural gas and NGLs. To manage a portion of our exposure to price volatility from producing crude oil and natural gas, we utilize the following economic hedging strategies for each of our business segments.

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

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

We believe our derivative instruments continue to be effective in achieving the risk management objectives for which they were intended. As of June 30, 2013, we had derivative instruments, which were comprised of commodity floors, collars and swaps, basis protection swaps and physical sales and purchases, in place for a portion of our anticipated production through 2017 for a total of 47,679 BBtu of natural gas and 5,392 MBbls of crude oil.

We have elected not to designate any of our derivative instruments as hedges and therefore do not qualify for use of hedge accounting. Accordingly, changes in the fair value of our derivative instruments are recorded in the statements of operations, with the exception of changes in fair value related to those derivatives we designated to our affiliated partnerships. Changes in the fair value of derivative instruments related to our Oil and Gas Exploration and Production segment are recorded in commodity price risk management, net. Changes in the fair value of derivative instruments related to our Gas Marketing segment are recorded in sales from and cost of natural gas marketing. Changes in the fair value of the derivative instruments designated to our affiliated partnerships are recorded on the balance sheets in accounts payable affiliates and accounts receivable affiliates. As positions designated to our affiliated partnerships settle, the realized gains and losses are netted for distribution. Net realized gains are paid to the partnerships and net realized losses are deducted from the partnerships' cash distributions from production. The affiliated partnerships bear their designated share of counterparty risk.

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

The following table presents the location and fair value amounts of our derivative instruments on the balance sheets as of June 30, 2013 and December 31, 2012:

Derivatives instruments:		Balance sheet line item	Fair Value June 30, 2013 (in thousands)	December 31, 2012
Derivative assets:	Current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	$15,099	$47,016
	Related to affiliated partnerships (1) (3)	Fair value of derivatives	—	4,707
	Related to natural gas marketing	Fair value of derivatives	661	302
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	506	—
	Related to natural gas marketing	Fair value of derivatives	21	17
			16,287	52,042
	Non Current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	10,197	6,671
	Related to natural gas marketing	Fair value of derivatives	92	203
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	129	—
	Related to natural gas marketing	Fair value of derivatives	3	9
			10,421	6,883
Total derivative assets			$26,708	$58,925
Derivative liabilities:	Current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	$2,968	$1,744
	Related to natural gas marketing	Fair value of derivatives	507	226
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	2,224	14,329
	Related to affiliated partnerships (2) (3)	Fair value of derivatives	—	2,140
	Related to natural gas marketing		3	—

		Fair value of derivatives	5,702	18,439
	Non Current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	4,437	9,969
	Related to natural gas marketing	Fair value of derivatives	36	168
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	2	—
			4,475	10,137
Total derivative liabilities			$10,177	$28,576

(1) 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.

(2) 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.

(3) In June 2013, all remaining derivative positions designated to our affiliated partnerships were liquidated prior to settlement. The net proceeds are included in the balance sheet line item accounts payable affiliates.

Table of contents
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	2013 Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	2013 Realized and Unrealized Gains (Losses) For the Current Period	2013 Total	2012 Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	2012 Realized and Unrealized Gains (Losses) For the Current Period	2012 Total
	(in thousands)					
Three Months Ended June 30,						
Commodity price risk management gain, net						
Realized gains	$3,210	$ 693	$3,903	$13,503	$ 2,676	$16,179
Unrealized gains (losses)	(3,210)	24,031	20,821	(13,503)	36,053	22,550
Total commodity price risk management gain, net	$—	$ 24,724	$24,724	$—	$ 38,729	$38,729
Sales from natural gas marketing						
Realized gains (losses)	$(149)	$ (24)	$(173)	$749	$ 3	$752
Unrealized gains (losses)	149	1,472	1,621	(749)	(322)	(1,071)
Total sales from natural gas marketing	$—	$ 1,448	$1,448	$—	$ (319)	$(319)
Cost of natural gas marketing						
Realized gains (losses)	$191	$ 34	$225	$(692)	$ (26)	$(718)
Unrealized gains (losses)	(191)	(1,445)	(1,636)	692	375	1,067
Total cost of natural gas marketing	$—	$ (1,411)	$(1,411)	$—	$ 349	$349
Six Months Ended June 30,						
Commodity price risk management gain, net						
Realized gains (losses)	$17,771	$ (5,397)	$12,374	$16,046	$ 10,060	$26,106
Unrealized gains (losses)	(17,771)	7,766	(10,005)	(16,046)	40,170	24,124
Total commodity price risk management gain, net	$—	$ 2,369	$2,369	$—	$ 50,230	$50,230
Sales from natural gas marketing						
Realized gains (losses)	$209	$ (181)	$28	$1,110	$ 435	$1,545
Unrealized gains (losses)	(209)	860	651	(1,110)	114	(996)
Total sales from natural gas marketing	$—	$ 679	$679	$—	$ 549	$549
Cost of natural gas marketing						
Realized gains (losses)	$(153)	$ 216	$63	$(970)	$ (493)	$(1,463)
Unrealized gains (losses)	153	(712)	(559)	970	(19)	951
Total cost of natural gas marketing	$—	$ (496)	$(496)	$—	$ (512)	$(512)

All of our financial derivative agreements contain master netting provisions that provide for the net settlement of all contracts through a single payment in the event of early termination. Our fixed-price physical purchase and sale agreements that qualify as derivative contracts are not subject to master netting provisions and are not significant. We have elected not to offset the fair value positions recorded on our condensed consolidated balance sheets.

The following table reflects the impact of netting agreements on gross derivative assets and liabilities as of June 30, 2013 and December 31, 2012:

As of June 30, 2013	Derivatives instruments, recorded in condensed consolidated balance sheet, gross	Effect of master netting agreements	Derivative instruments, net
Asset derivatives:			
Derivative instruments, at fair value	$26,708	$(7,508)	$19,200
Liability derivatives:			
Derivative instruments, at fair value	$10,177	$(7,508)	$2,669

As of December 31, 2012	Derivatives instruments, recorded in condensed consolidated balance sheet, gross	Effect of master netting agreements	Derivative instruments, net
Asset derivatives:			
Derivative instruments, at fair value	$58,925	$(11,437)	$47,488
Liability derivatives:			
Derivative instruments, at fair value	$28,576	$(11,437)	$17,139

NOTE 5 - PROPERTIES AND EQUIPMENT

The following table presents the components of properties and equipment, net of accumulated depreciation, depletion and amortization:

	June 30, 2013	December 31, 2012
	(in thousands)	
Properties and equipment, net:		
Crude oil and natural gas properties		
Proved	$1,459,066	$2,075,924
Unproved	316,301	319,327
Total crude oil and natural gas properties	1,775,367	2,395,251
Pipelines and related facilities	15,094	47,786
Equipment and other	27,893	34,858
Land and buildings	13,507	14,935
Construction in progress	90,452	67,217
Gross properties and equipment	1,922,313	2,560,047
Accumulated depreciation, depletion and amortization	(483,433)	(943,341)
Properties and equipment, net	$1,438,880	$1,616,706

10

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

The following table presents impairment charges recorded for crude oil and natural gas properties:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(in thousands)			
Continuing operations:				
Impairment of proved properties	$—	$—	$45,000	$—
Impairment of individually significant unproved properties	671	154	825	308
Amortization of individually insignificant unproved properties	831	202	2,136	636
Total continuing operations	1,502	356	47,961	944
Discontinued operations:				
Amortization of individually insignificant unproved properties	—	14	3	79
Total discontinued operations	—	14	3	79
Total impairment of crude oil and natural gas properties	$1,502	$370	$47,964	$1,023

In the first quarter of 2013, we recognized an impairment charge of approximately $45 million related to all of our shallow upper Devonian (non-Marcellus Shale) Appalachian Basin producing properties located in West Virginia and Pennsylvania owned directly by us, as well as through our proportionate share of PDCM and our affiliated partnerships. The impairment charge represented the excess of the carrying value of the assets over the estimated fair value, less cost to sell. The fair value of the assets was determined based upon estimated future cash flows from unrelated third-party bids, a Level 3 input. The impairment charge was included in the statement of operations line item impairment of crude oil and natural gas properties. See Note 12, Assets Held for Sale, Divestitures and Discontinued Operations, for additional information regarding these properties.

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 June 30, 2013 was a 37.2% expense on income and 34.2% benefit on loss, respectively, compared to a 34.7% and 35.6% expense on income for the three and six months ended June 30, 2012, respectively. The effective tax rates for the three and six months ended June 30, 2013 differ from the statutory rate primarily due to net permanent additions, largely nondeductible officers' compensation, partially offset by percentage depletion deduction. For the six months ended June 30, 2013, the nondeductible item for officers' compensation exceeded our deduction for percentage depletion, thereby reducing our tax benefit rate. Additionally, state statutory limits on the utilization of our net operating losses resulted in a reduced state tax benefit. The effective tax rates for the three and six months ended June 30, 2012 differ from the statutory rate primarily due to net permanent deductions, largely percentage depletion partially offset by nondeductible officer's compensation. There were no significant discrete items recorded during the three and six months ended June 30, 2013 or 2012.

As of June 30, 2013, we had a gross liability for unrecognized tax benefits of $0.2 million, unchanged from the amount recorded at December 31, 2012. If recognized, this liability would affect our effective tax rate. This liability is reflected in other accrued expenses on our accompanying balance sheets. We expect our remaining liability for uncertain tax positions to decrease in the next twelve months due to the expiration of statute of limitations.

As of the date of this filing, we are current with our income tax filings in all applicable state jurisdictions. We have received notice from the State of Colorado that our state income tax returns for the tax years 2008 through 2011 have been selected for audit.

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

NOTE 7 - LONG-TERM DEBT

Long-term debt consists of the following:

	June 30, 2013	December 31, 2012
	(in thousands)	
Senior notes:		
3.25% Convertible senior notes due 2016:		
Principal amount	$115,000	$115,000
Unamortized discount	(11,873)	(13,671)
3.25% Convertible senior notes due 2016, net of discount	103,127	101,329
7.75% Senior notes due 2022	500,000	500,000
Total senior notes	603,127	601,329
Credit facilities:		
Corporate	—	49,000
PDCM	36,000	26,250
Total credit facilities	36,000	75,250
Total long-term debt	$639,127	$676,579

Senior Notes

3.25% Convertible Senior Notes Due 2016. In November 2010, we issued $115 million aggregate principal amount 3.25% convertible senior notes due May 15, 2016 (the "2016 Convertible Senior Notes") in a private placement to qualified institutional investors. Interest on the 2016 Convertible Senior Notes is payable semi-annually in arrears on each May 15 and November 15. We allocated the gross proceeds of the convertible senior notes between the liability and equity components of the debt. The initial $94.3 million liability component was determined based upon the fair value of similar debt instruments with similar terms, excluding the conversion feature, and priced on the same day we issued our convertible senior notes. The original issue discount and capitalized debt issuance costs are being amortized to interest expense over the life of the notes using an effective interest rate of 7.4%.

Upon conversion, the convertible senior 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 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.

7.75% Senior Notes Due 2022. In October 2012, we issued $500 million aggregate principal amount 7.75% senior notes due October 15, 2022 (the “2022 Senior Notes”) in a private placement to qualified institutional investors. Interest on the 2022 Senior Notes is payable semi-annually in arrears on each April 15 and October 15. The indenture governing the notes contains customary restrictive incurrence covenants. Capitalized debt issuance costs are being amortized as interest expense over the life of the notes using the effective interest method.

As of June 30, 2013, we were in compliance with all covenants related to the 2016 Convertible Senior Notes and the 2022 Senior Notes, and expect to remain in compliance throughout the next twelve-month period.

In connection with the issuance of the 2022 Senior Notes, we entered into a registration rights agreement with the initial purchasers in which we agreed to file a registration statement with the SEC related to an offer to exchange the notes for other freely tradable notes and to use commercially reasonable efforts to cause the exchange offer to be completed on or prior to September 28, 2013. The registration statement was declared effective July 9, 2013.

Credit Facilities

Revolving Credit Facility. In May 2013, we entered into a Third Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A. as administrative agent and other lenders party thereto. This agreement amends and restates the credit agreement dated November 2010 and expires in May 2018. The revolving credit facility is available for working capital requirements, capital expenditures, acquisitions, general corporate purposes and to support letters of credit. The revolving credit facility provides for a maximum of $1 billion in allowable borrowing capacity, subject to the borrowing base. As of June 30, 2013, the borrowing base on the revolving credit facility was $450 million. The borrowing base of the revolving credit facility is based on, among other things, the loan value assigned to the proved reserves attributable to our and our subsidiaries' crude oil and natural gas interests, excluding proved reserves attributable to PDCM and our 21 affiliated partnerships. Our revolving credit facility borrowing base is subject to a semi-annual size redetermination based upon quantification of our reserves at June 30 and December 31, and is also subject to a redetermination upon the occurrence of certain events. The revolving credit facility is secured by a pledge of the stock of certain of our subsidiaries, mortgages of certain producing crude oil and natural gas 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 revolving credit facility. As of June 30, 2013, we had no outstanding draws on our revolving credit facility compared to $49 million at a weighted-average interest rate of 2.3% as of December 31, 2012.

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 in May 2018, or in the event that the borrowing base would fall below the outstanding balance.

The revolving credit facility contains covenants customary for agreements of this type, with the most restrictive being certain financial tests and requirements to maintain certain financial ratios on a quarterly basis. The financial tests and ratios, as defined per the revolving credit facility, include requirements to maintain a minimum current ratio of 1.00 to 1.00 and to not exceed a maximum leverage ratio of 4.25 to 1.00.

As of June 30, 2013 we had an $18.7 million irrevocable standby letter of credit outstanding in favor of a third-party transportation service provider to secure firm transportation of the natural gas produced by us and others for whom we market production in West Virginia. The letter of credit reduces the amount of available funds under our revolving 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 (1.5% per annum as of June 30, 2013) for the period in which the letter of credit remains outstanding. The letter of credit expires on July 20, 2014. We expect to renew the letter of credit prior to its expiration.

We pay a fee of 0.375% per annum on the unutilized commitment on the available funds under our revolving credit facility. As of June 30, 2013, the available funds under our revolving credit facility, including a reduction for the $18.7 million irrevocable standby letter of credit in effect, was $431.3 million.

As of June 30, 2013, we were in compliance with all the revolving credit facility covenants and expect to remain in compliance throughout the next twelve-month period.

PDCM Credit Facility. PDCM has a credit facility dated April 2010, as amended in May 2013, with an aggregate revolving commitment or borrowing base of $80 million, of which our proportionate share is $40 million. The maximum allowable facility amount is $400 million. At PDCM's discretion, interest accrues at either an alternative base rate ("ABR") or an adjusted LIBOR. The ABR is the greater of Wells Fargo's prime rate, the federal funds effective rate plus 0.5% or the adjusted LIBOR for a three month interest period plus 1%. ABR and adjusted LIBOR borrowings are assessed an additional margin based upon the outstanding balance as a percentage of the available balance. ABR borrowings are assessed an additional margin of 1.25% to 2.0%. Adjusted LIBOR borrowings are assessed an additional margin spread of 2.25% to 3.0%. No principal payments are required until the credit agreement expires in April 2017, or in the event that the borrowing base falls below the outstanding balance. 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 semi-annually based upon a valuation of PDCM's reserves at June 30 and December 31. Either PDCM or the lenders may request a redetermination upon the occurrence of certain events. The credit facility will be utilized by PDCM for the exploration and development of its Marcellus Shale assets.

The credit facility contains covenants customary for agreements of this type, with the most restrictive being certain financial tests and financial ratios that must be met on a quarterly basis. The financial tests and ratios, as defined by the credit facility, include requirements to maintain a minimum current ratio of 1.0 to 1.0, not to exceed a debt to

EBITDAX ratio of 5.0 to 1.0 (declining to 4.25 to 1.0 on July 1, 2013 and to 4.0 to 1.0 on July 1, 2014) and to maintain a minimum interest coverage ratio of 2.5 to 1.0. As of June 30, 2013, our proportionate share of PDCM's outstanding credit facility balance was $36.0 million compared to $26.3 million as of December 31, 2012. PDCM is required to pay a commitment fee of 0.5% per annum on the unutilized portion of the credit facility. The weighted-average borrowing rate on PDCM's credit facility was 3.6% per annum as of June 30, 2013, compared to 3.5% as of December 31, 2012.

As of June 30, 2013, PDCM was not in compliance with the minimum current ratio covenant under the PDCM credit facility. In July 2013, PDCM received a waiver from Wells Fargo regarding the covenant violation. PDCM expects to maintain compliance with all PDCM credit facility covenants throughout the next twelve-month period.

In July 2013, PDCM entered into a Second Lien Credit Agreement. See Note 15, Subsequent Events, for additional information.

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

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 crude oil and natural gas properties:

	Amount (in thousands)
Balance at December 31, 2012	$62,563
Obligations incurred with development activities	211
Accretion expense	2,481
Revisions in estimated cash flows	963
Obligations discharged with disposal of properties and asset retirements	(7,481)
Balance at June 30, 2013	58,737
Liabilities held for sale (1)	(22,370)
Less current portion	(1,000)
Long-term portion	$35,367

____

(1) Represents asset retirement obligations related to our assets held for sale. See Note 12, Assets Held for Sale, Divestitures and Discontinued Operations, for additional information regarding the planned sale of these properties.

NOTE 9 - COMMITMENTS AND CONTINGENCIES

Firm Transportation Agreements. We enter into contracts that provide firm transportation, sales and processing services on pipeline systems through which we transport or sell natural gas. Volumes produced by us, PDCM, our affiliated partnerships and other third-party working interest owners can be used to satisfy volume requirements, as can volumes purchased from third parties. We record in our financial statements only our share of costs based upon our working interest in the wells. These contracts require us to pay these transportation and processing charges whether the required volumes are delivered or not. With the exception of contracts entered into by PDCM, the costs of any volume shortfalls are borne by PDC.

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

	For the Twelve Months Ending June 30,						
Area	2014	2015	2016	2017	2018 and Through Expiration	Total	Expiration Date
Volume (MMcf)							
West Virginia	20,644	22,855	24,369	24,862	155,869	248,599	September 20, 2025
Utica Shale	1,935	2,737	2,737	2,738	16,658	26,805	July 22, 2023
Total	22,579	25,592	27,106	27,600	172,527	275,404	
Dollar commitment (in thousands)	$9,320	$10,054	$10,361	$10,455	$50,258	$90,448	

In March 2013, we entered into long-term agreements with a subsidiary of MarkWest Energy Partners, LP to provide midstream services, including gas gathering, processing, fractionation and marketing, to support our Utica Shale operations in Guernsey County in Southeast Ohio. The primary term of the agreements commenced in July 2013 when our natural gas began to flow into the gathering system. The gas processing agreement includes minimum volume commitments as shown in the table above, with certain fees assessed for any shortfall.

In June 2013, we closed a transaction pursuant to which our Piceance Basin and NECO firm gathering commitments were assumed by the buyer of certain of our oil and natural gas properties. See Note 12, Assets Held for Sale, Divestitures, and Discontinued Operations, for additional information regarding the sale of our non-core Colorado assets.

Litigation. The Company is involved in various legal proceedings that it considers normal to its business. The Company reviews the status of these proceedings on an ongoing basis and, from time to time, may settle or otherwise resolve these matters on terms and conditions that management believes are in the best interests of the Company. There is no assurance 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 its 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 that the disclosures in the proxy statements issued in connection with the mergers were inadequate, and a state law breach of fiduciary duty. On June 15, 2012, the Court denied the Company's motion to dismiss and 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 and because the plaintiffs have not specified damages and it is not possible for management to reasonably estimate what, if any, monetary damages could result from this claim.

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 recorded when environmental damages resulting from past events are probable and the costs can be reasonably estimated. As of June 30, 2013 and December 31, 2012, we had accrued environmental liabilities in the amount of $4.9 million and $8.4 million, respectively, included in other accrued expenses on the balance sheets. We are not aware of any environmental claims existing as of June 30, 2013 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 where investing partners may request that we purchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that we are obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions from production), if repurchase is requested by investors, subject to our financial ability to do so. As of June 30, 2013, 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 potential obligation. For the quarter ended June 30, 2013, amounts paid for the repurchase of partnership units pursuant to this provision were immaterial.

Employment Agreements with Executive Officers. Each of our senior executive officers may be entitled to a severance payment and certain other benefits upon the termination of the officer's employment pursuant to the officer's employment agreement and/or the Company's executive severance compensation plan. The nature and amount of such benefits would vary based upon, among other things, whether the termination followed a change of control of the Company.

NOTE 10 - COMMON STOCK

Stock-Based Compensation Plans

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012

	(in thousands)			
Stock-based compensation expense	$4,349	$1,955	$6,951	$3,901
Income tax benefit	(1,661)	(744)	(2,655)	(1,486)
Net stock-based compensation expense	$2,688	$1,211	$4,296	$2,415

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 2013, the Compensation Committee awarded 87,078 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,			
	2013		2012	
Expected term of award	6 years		6 years	
Risk-free interest rate	1.0	%	1.1	%
Expected volatility	65.5	%	64.3	%
Weighted-average grant date fair value per share	$21.96		$17.61	

The expected life of the award was estimated using historical stock option exercise behavior data. The risk-free interest rate was based on the U.S. Treasury yields approximating the expected life of the award in effect at the time of grant. Expected volatilities were based on our historical volatility. We do not expect to pay or declare dividends in the foreseeable future.

The following table presents the changes in our SARs:

	Six Months Ended June 30,							
	2013				2012			
	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,	118,832	$ 30.80	8.4	$ 486	50,471	$ 31.61	8.6	$ 341
Awarded	87,078	37.18	—	—	68,361	30.19	—	—
Outstanding at June 30,	205,910	33.50	8.6	3,703	118,832	30.80	8.9	3
Vested and expected to vest at June 30,	196,421	33.40	8.6	3,552	112,285	30.76	8.9	3
Exercisable at June 30,	67,069	29.99	7.6	1,441	27,458	28.84	8.0	2

Total compensation cost related to SARs granted, net of estimated forfeitures, and not yet recognized in our statement of operations as of June 30, 2013 was $2.2 million. The cost is expected to be recognized over a weighted-average period of 2.2 years.

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 if the participant is continuously employed.

In January 2013, the Compensation Committee awarded a total of 103,050 time-based restricted shares to our executive officers that vest ratably over a three-year period ending on January 16, 2016.

The following table presents the changes in non-vested time-based awards for the six months ended June 30, 2013:

Shares

		Weighted-Average Grant-Date Fair Value
Non-vested at December 31, 2012	646,490	$27.93
Granted	281,879	44.24
Vested	(189,939)	28.69
Forfeited	(18,102)	29.54
Non-vested at June 30, 2013	720,328	34.08

16

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

	As of/Year Ended June 30,	
	2013	2012
	(in thousands, except per share data)	
Total intrinsic value of time-based awards vested	$8,544	$4,315
Total intrinsic value of time-based awards non-vested	37,082	12,602
Market price per common share as of June 30,	51.48	24.52
Weighted-average grant date fair value per share	44.24	29.58

Total compensation cost related to non-vested time-based awards, net of estimated forfeitures, and not yet recognized in our statements of operations as of June 30, 2013 was $18.4 million. This cost is expected to be recognized over a weighted-average period of 2.4 years.

Market-Based Awards. The fair value of the market-based restricted shares is amortized ratably over the requisite service period, primarily three years. 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 between three to 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 2013, the Compensation Committee awarded a total of 41,570 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 16 peer companies. The shares are measured over a three-year period ending on December 31, 2015 and can result in a payout between 0% 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,			
	2013		2012	
Expected term of award	3 years		3 years	
Risk-free interest rate	0.4	%	0.3	%
Expected volatility	56.6	%	65.3	%
Weighted-average grant date fair value per share	$49.04		$36.54	

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 non-vested market-based awards during six months ended June 30, 2013:

	Shares	Weighted-Average Grant-Date Fair Value per Share
Non-vested at December 31, 2012	40,696	$39.22
Granted	41,570	49.04
Non-vested at June 30, 2013	82,266	44.18

	As of/Year Ended June 30, 2013	2012
	(in thousands, except per share data)	
Total intrinsic value of market-based awards non-vested	$4,235	$1,805
Market price per common share as of June 30,	51.48	24.52
Weighted-average grant date fair value per share	49.04	36.54

Total compensation cost related to non-vested market-based awards, net of estimated forfeitures, and not yet recognized in our statement of operations as of June 30, 2013 was $2.3 million. This cost is expected to be recognized over a weighted-average period of 2.2 years.

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

NOTE 11 - EARNINGS PER SHARE

Basic earnings per share is computed by dividing net earnings by the weighted-average number of common shares outstanding for the period. Diluted earnings per share is similarly computed except that the denominator includes the effect, using the treasury stock method, of unvested restricted stock, outstanding SARs, stock options, convertible senior notes and shares held pursuant to our non-employee director deferred compensation plan, if including such potential shares of common stock is dilutive.

The following table presents a reconciliation of the weighted-average diluted shares outstanding:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(in thousands)			
Weighted-average common shares outstanding - basic	30,332	26,597	30,301	25,103
Dilutive effect of:				
Restricted stock	313	125	—	157
SARs	26	3	—	4
Stock options	1	—	—	—
Non-employee director deferred compensation	4	3	—	4
Convertible senior notes	338	—	—	—
Weighted-average common shares and equivalents outstanding - diluted	31,014	26,728	30,301	25,268

The following table presents 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,	
	2013	2012	2013	2012
	(in thousands)			
Weighted-average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:				
Restricted stock	5	90	893	64
SARs	20	87	54	81
Stock options	—	7	7	7
Non-employee director deferred compensation	—	—	4	—
Convertible senior notes	—	—	206	—
Total anti-dilutive common share equivalents	25	184	1,164	152

We reported a net loss for the six months ended June 30, 2013. As a result, our basic and diluted weighted-average common shares outstanding was the same as the effect of the common share equivalents was anti-dilutive.

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. These convertible senior notes could be included in the dilutive earnings per share calculation using the treasury stock method if the average market share price exceeds the $42.40 conversion price during the period presented. Shares issuable under the convertible senior notes were included in the diluted earnings per share calculation for the three months ended June 30, 2013 as the average market price during the period exceeded the conversion price. Shares issuable under the convertible senior notes were excluded from the diluted earnings per share calculation for the six months ended June 30, 2013 as the effect would be anti-dilutive to our earnings. Shares issuable under the convertible senior notes were excluded from the diluted earnings per share calculation for the three and six months ended June 30, 2012 as the conversion price was greater than the average market price of our common stock during the period.

NOTE 12 - ASSETS HELD FOR SALE, DIVESTITURES AND DISCONTINUED OPERATIONS

Piceance Basin and NECO. In February 2013, we entered into a purchase and sale agreement with certain affiliates of Caerus Oil and Gas LLC (“Caerus”), pursuant to which we agreed to sell to Caerus our Piceance Basin, NECO and certain other non-core Colorado oil and gas properties, leasehold mineral interests and related assets. Additionally, certain firm transportation obligations and natural gas hedging positions were assumed by Caerus. On June 18, 2013, this divestiture was completed with total consideration of approximately $177.6 million, subject to customary post-closing adjustments, with an additional $17.0 million paid to our non-affiliated investor partners. The sale resulted in a pre-tax loss of $1.1 million. The proceeds from the asset disposal were used to pay down our revolving credit facility and to fund a portion of our 2013 capital budget. Following the sale to Caerus, we do not have significant continuing involvement in the operations of, or cash flows from, the Piceance Basin and NECO oil and gas properties. Accordingly, the results of operations related to these assets have been separately reported as discontinued operations in the condensed consolidated statement of operations for all periods presented. The sale of our other non-core Colorado oil and gas properties did not meet the requirements to be accounted for as discontinued operations.

Appalachian Basin. In early 2013, we developed a plan to market all of our shallow upper Devonian (non-Marcellus Shale) Appalachian Basin crude oil and natural gas properties located in West Virginia and Pennsylvania owned directly by us, as well as through our proportionate share of PDCM and our affiliated partnerships. The properties being marketed consist of approximately 3,500 gross shallow producing wells, related facilities and associated shallow leasehold acreage, limited to the upper Devonian and shallower formations. The company will retain all zones, formations and intervals below the upper Devonian formation including the Marcellus Shale, Utica Shale and Huron Shale. We anticipate that any proceeds from the sale of these shallow upper Devonian assets will be used to fund a portion of our Marcellus drilling program in the Appalachian Basin. We have classified the related assets owned directly by us, as well as through our proportionate share of PDCM and our affiliated partnerships, as held for sale in the condensed consolidated balance sheet as of June 30, 2013. The planned divestiture of these assets does not meet the requirements to be accounted for as discontinued operations.

Permian Basin. In December 2011, we executed a purchase and sale agreement with COG Operating LLC ("COG"), a wholly owned subsidiary of Concho Resources Inc., an unrelated third-party, for the sale of our core Permian Basin assets for a sale price of $173.9 million, subject to customary terms and adjustments. In February 2012, the divestiture closed with total proceeds received of $189.2 million after closing adjustments. Following the sale to COG, 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 Permian assets have been separately reported as discontinued operations in the condensed consolidated statement of operations for the three and six months ended June 30, 2012.

Selected financial information related to divested and discontinued operations. The tables below set forth selected financial information related to net assets held for sale and operating results related to discontinued operations. Net assets held for sale represents the Appalachian Basin assets that are expected to be sold, net of liabilities that are expected to be assumed by the purchaser.

The following table presents balance sheet data related to our pro rata share of these assets held for sale as of June 30, 2013:

Balance Sheet	Net Assets Held for Sale (in thousands)
Assets	
Properties and equipment	$130,243
Accumulated depreciation, depletion and amortization	(98,083)
Total Assets	32,160
Liabilities	
Asset retirement obligation	22,370
Net Assets	$9,790

The following table presents statement of operations data related to our discontinued operations for the Piceance Basin, NECO and Permian Basin divestiture:

	Three Months Ended June 30,		Six Months Ended June 30,	
Statements of Operations - Discontinued Operations	2013	2012	2013	2012
	(in thousands)			
Revenues				
Crude oil, natural gas and NGLs sales	$10,182	$5,537	$20,456	$18,348
Sales from natural gas marketing	586	304	1,036	757
Well operations, pipeline income and other	409	464	859	1,030
Total revenues	11,177	6,305	22,351	20,135
Costs, expenses and other				
Production costs	2,564	5,682	7,957	12,784
Cost of natural gas marketing	540	271	994	672
Depreciation, depletion and amortization	—	10,609	2,258	22,511
Other	1,959	303	2,454	651
(Gain) loss on sale of properties and equipment	1,076	415	1,076	(19,920)
Total costs, expenses and other	6,139	17,280	14,739	16,698
Income (loss) from discontinued operations	5,038	(10,975)	7,612	3,437
Provision for income taxes	(1,622)	4,068	(2,659)	(1,273)
Income (loss) from discontinued operations, net of tax	$3,416	$(6,907)	$4,953	$2,164

While the reclassification of revenues and expenses related to discontinued operations for the prior period had no impact upon previously reported net earnings, the statement of operations table presents the revenues and expenses that were reclassified from the specified statement of operations line items to discontinued operations.

NOTE 13 - TRANSACTIONS WITH AFFILIATES AND OTHER RELATED PARTIES

PDCM and Affiliated Partnerships. Our Gas Marketing segment markets the natural gas produced by PDCM and our affiliated partnerships in the Eastern operating region.

Amounts due from/to the affiliated partnerships have historically been primarily related to derivative positions and, to a lesser extent, unbilled well lease operating expenses, and costs resulting from audit and tax preparation services. Previously, we had entered into derivative instruments on behalf of our affiliated partnerships for their estimated production.

The following table presents amounts included in our condensed consolidated statements of operations related to the marketing of natural gas on behalf of PDCM and our affiliated partnerships and amounts included in our condensed consolidated balance sheets related to the derivative instruments we entered into on behalf of our affiliated partnerships:

Statement of Operations	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
	(in thousands)			
PDCM:				
Sales from natural gas marketing	$4,243	$2,123	$7,968	$4,565
Cost of natural gas marketing	4,160	2,081	7,812	4,475
Affiliated Partnerships:				
Sales from natural gas marketing	309	104	583	223
Cost of natural gas marketing	303	102	572	218

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

Balance Sheet	As of June 30, 2013	December 31, 2012
	(in thousands)	
Affiliated Partnerships:		
Receivable from affiliated partnerships	$—	$2,140
Payable to affiliated partnerships	—	4,707

We provide certain well operating and administrative services for PDCM. Amounts billed to PDCM for these services were $3.4 million and $6.8 million in the three and six months ended June 30, 2013, respectively, compared to $3.0 million and $6.2 million in the three and six months ended June 30, 2012. Our statements of operations include only our proportionate share of these billings. The following table presents the statement of operations line item in which our proportionate share is recorded and the amount for each of the periods presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
Statement of Operations Line Item	2013	2012	2013	2012
	(in thousands)			
Production costs	$986	$1,002	$2,053	$2,058
Exploration expense	134	115	239	247
General and administrative expense	618	384	1,132	798

NOTE 14 - BUSINESS SEGMENTS

We separate our operating activities into two segments: (1) Oil and Gas Exploration and Production and (2) Gas Marketing. All material inter-company accounts and transactions between segments have been eliminated.

Oil and Gas Exploration and Production. Our Oil and Gas Exploration and Production segment includes all of our crude oil and natural gas properties. The segment represents revenues and expenses from the production and sale of crude oil, natural gas and NGLs. Segment revenue includes crude oil, natural gas and NGLs 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 crude oil and natural gas 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) primarily represents sales from natural gas marketing and direct interest income, less costs of natural gas marketing and direct general and administrative expense.

Unallocated amounts. Unallocated income includes corporate general administrative expense, corporate depreciation, depletion and amortization expense, interest income and interest expense.

The following tables present our segment information:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(in thousands)			
Revenues:				
Oil and gas exploration and production	$103,226	$91,127	$161,382	$170,752
Gas marketing	18,079	8,613	31,749	19,994

Total revenues	$121,305	$99,740	$193,131	$190,746
Segment income (loss) before income taxes:				
Oil and gas exploration and production	$56,372	$55,694	$22,671	$93,118
Gas marketing	13	123	(52)	413
Unallocated	(30,092)	(26,426)	(59,773)	(53,256)
Total	$26,293	$29,391	$(37,154)	$40,275

21

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

	June 30, 2013	December 31, 2012
	(in thousands)	
Segment assets:		
Oil and gas exploration and production	$1,557,352	$1,723,011
Gas marketing	34,097	11,090
Unallocated	67,826	92,747
Assets held for sale	32,160	—
Total Assets	$1,691,435	$1,826,848

NOTE 15 - SUBSEQUENT EVENTS

In July 2013, PDCM entered into a Second Lien Credit Agreement ("Credit Agreement") with Wells Fargo Energy Capital as administrative agent and a syndicate of other lenders party thereto. The aggregate commitment under the Credit Agreement is $30 million, of which our proportionate share is $15 million. The aggregate commitment may increase periodically up to a maximum of $75 million, as PDCM's assets grow and the covenants under the Credit Agreement allow. The Credit Agreement matures on October 31, 2017. Amounts borrowed accrue interest, at PDCM's discretion, at either an alternative base rate plus a margin of 6% per annum or an adjusted LIBOR for the interest period in effect plus a margin of 7% per annum.

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

The following discussion and analysis, as well as other sections in this report, should be read in conjunction with our condensed consolidated financial statements and related notes included elsewhere in this report. Further, we encourage you to revisit the Special Note Regarding Forward-Looking Statements.

EXECUTIVE SUMMARY

Financial Overview

We recorded strong increases in crude oil, natural gas and NGLs sales from continuing operations during the three and six months ended June 30, 2013 as a result of our significant increase in production and much higher natural gas prices. Total crude oil, natural gas and NGLs sales increased $26.2 million, or 51.0%, and $38.7 million, or 32.7%, during the three and six months ended June 30, 2013, respectively, compared to the three and six months ended June 30, 2012. Our crude oil, natural gas and NGLs production from continuing operations during the six months ended June 30, 2013 averaged 18.3 Mboe per day, an increase of approximately 25.3% compared to the six months ended June 30, 2012. The increase in production is primarily attributable to our successful horizontal Niobrara and Codell drilling program in the Wattenberg Field and, to a lesser extent, certain assets acquired from affiliates of Merit Energy in June 2012. Crude oil production from continuing operations increased 39.7% and 30.3% during the three and six months ended June 30, 2013, respectively, while NGL production from continuing operations increased 44.3% and 22.9%, respectively. Our liquids percentage of total production from continuing operations was 54.3% during the three and six months ended June 30, 2013 compared to 51.5% and 53.0%, respectively, during the same prior year periods. Natural gas production from continuing operations increased 26.1% and 21.4% during the three and six months ended June 30, 2013, respectively, compared to the same periods in 2012.

Available liquidity as of June 30, 2013 was $478.5 million, including $4.4 million through PDCM, compared to $398.6 million, including $14.1 million related to PDCM, as of December 31, 2012. Available liquidity is comprised of cash, cash equivalents and funds available under revolving credit facilities. The increase in available liquidity was primarily attributable to proceeds received from the divestiture of our Piceance Basin and NECO assets in June 2013. We believe we have sufficient liquidity to allow us to execute our 2013 drilling program.

Operational Overview

Drilling Activities. We continued towards our strategic goal of increasing production and our production mix of crude oil and natural gas liquids by continuing to focus our operations primarily in the oil- and liquid-rich Wattenberg Field in Colorado and the emerging Utica Shale play in Ohio. In our Western operating region, we currently have three drilling rigs operating in the Wattenberg Field and are drilling on three- to eight-well pads. We spud 27 horizontal wells in the Wattenberg Field, 14 of which were completed, during the six months ended June 30, 2013, and participated in 18 gross, 4.2 net, horizontal non-operated drilling projects. We also executed six refracture and/or recompletion projects on three wells in the Wattenberg Field.

In our Eastern operating region, we spud five horizontal Utica wells during the six months ended June 30, 2013, all of which were in various stages of completion as of June 30, 2013. These wells are expected to be turned-in-line during the second half of 2013. Of the wells drilled in 2012, natural gas production from one well is being processed through a Company-operated refrigeration processing unit and sold through a temporary arrangement pending tie-in to a permanent gathering line expected during the third quarter, while crude oil and condensate from the well is being sold at the wellhead. The second well remains shut-in awaiting a gathering line connection. In addition, PDCM spud seven horizontal Marcellus wells during the six months ended June 30, 2013, all of which were in various stages of completion as of June 30, 2013.

Crude Oil and Natural Gas Properties Divestitures. In February 2013, we entered into a purchase and sale agreement with certain affiliates of Caerus Oil and Gas LLC (“Caerus”), pursuant to which we agreed to sell to Caerus our Piceance Basin, NECO and certain other non-core Colorado oil and gas properties, leasehold mineral interests and related assets. On June 18, 2013, this divestiture was completed with total consideration of approximately $177.6 million, subject to customary post-closing adjustments, with an additional $17.0 million paid to our non-affiliated investor partners. The sale resulted in a pre-tax loss of $1.1 million. The proceeds from the asset disposal were used to pay down our revolving credit facility and to fund a portion of our 2013 capital budget. Following the sale to Caerus, we do not have significant continuing involvement in the operations of, or cash flows from, the Piceance Basin and NECO oil and gas properties. Accordingly, the results of operations related to these assets have been separately reported as discontinued operations in the condensed consolidated statement of operations for all periods presented.

Non-U.S. GAAP Financial Measures

We use "adjusted cash flows from operations," "adjusted net income (loss)" and "adjusted EBITDA," non-U.S. GAAP financial measures, for internal management reporting, when evaluating period-to-period changes and providing public guidance on possible future results. These measures are not measures of financial performance under U.S. GAAP and should be considered in addition to, not as a substitute for, net income (loss) or cash flows from operations, investing or financing activities, and should not be viewed as a liquidity measure or indicator of cash flows reported in accordance with U.S. GAAP. The non-U.S. GAAP financial measures that we use may not be comparable to similarly titled measures reported by other companies. Also, in the future, we may disclose different non-U.S. GAAP financial measures in order to help our investors more meaningfully evaluate and compare our future results of operations to our previously reported results of operations. We strongly encourage investors to review our financial statements and publicly filed reports in their entirety and to not rely on any single financial measure. See Reconciliation of Non-U.S. GAAP Financial Measures for a detailed description of these measures, as well as a reconciliation of each to the 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,		
	2013	2012	Percentage Change	2013	2012	Percentage Change
	(dollars in millions, except per unit data)					
Production (1)						
Crude oil (MBbls)	617.7	442.3	39.7 %	1,286.0	986.7	30.3 %
Natural gas (MMcf)	4,511.5	3,579.0	26.1 %	9,061.3	7,463.5	21.4 %
NGLs (MBbls)	276.5	191.6	44.3 %	514.8	418.8	22.9 %
Crude oil equivalent (MBoe) (2)	1,646.1	1,230.4	33.8 %	3,311.1	2,649.4	25.0 %
Average MBoe per day	18.1	13.5	34.1 %	18.3	14.6	25.3 %
Crude Oil, Natural Gas and NGLs Sales						
Crude oil	$53.9	$38.9	38.6 %	$112.1	$89.5	25.3 %
Natural gas	17.1	7.3	133.1 %	31.1	17.4	79.4 %
NGLs	6.5	5.1	27.5 %	13.8	11.5	20.1 %
Total crude oil, natural gas and NGLs sales	$77.5	$51.3	51.0 %	$157.0	$118.3	32.7 %
Realized Gain (Losses) on Derivatives, net (3)						
Natural gas	$3.1	$16.0	(80.4)%	$11.2	$28.5	(60.9)%
Crude oil	0.8	0.2	*	1.2	(2.4)	*
Total realized gain on derivatives, net	$3.9	$16.2	(75.9)%	$12.4	$26.1	(52.5)%
Average Sales Price (excluding gain (loss) on derivatives)						
Crude oil (per Bbl)	$87.32	$87.97	(0.7)%	$87.13	$90.67	(3.9)%
Natural gas (per Mcf)	3.79	2.05	84.9 %	3.44	2.33	47.6 %
NGLs (per Bbl)	23.55	26.65	(11.6)%	26.72	27.39	(2.4)%
Crude oil equivalent (per Boe)	47.10	41.73	12.9 %	47.41	44.65	6.2 %
Average Lifting Cost (per Boe) (4)						
Western operating region	$4.59	$4.90	(6.3)%	$4.27	$4.46	(4.3)%
Eastern operating region	6.82	8.30	(17.8)%	6.95	8.38	(17.1)%
Weighted-average	4.97	5.58	(10.9)%	4.72	5.19	(9.1)%
Natural Gas Marketing Contribution Margin (5)	$—	$0.1	*	$—	$0.4	*
Other Costs and Expenses						
Exploration expense	$1.4	$2.4	(39.5)%	$3.1	$4.2	(26.4)%
Impairment of crude oil and natural gas properties	1.5	0.4	*	48.0	0.9	*
General and administrative expense	15.8	14.4	9.8 %	30.9	29.1	6.2 %
Depreciation, depletion and amortization	27.8	23.8	16.6 %	55.7	51.8	7.7 %

Interest Expense	$13.1	$10.1	30.2	%	$26.4	$20.5	29.0	%

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

____

(1) Production is net and determined by multiplying the gross production volume of properties in which we have an interest by our ownership percentage.
(2) One Bbl of crude oil or NGL equals six Mcf of natural gas.
(3) Represents realized derivative gains and losses related to crude oil and natural gas sales, which do not include realized derivative gains and losses related to natural gas marketing.
(4) Represents lease operating expenses, exclusive of production taxes, on a per unit basis.
(5) Represents sales from natural gas marketing, net of costs of natural gas marketing, including realized and unrealized derivative gains and losses related to natural gas marketing activities.

Table of contents
PDC ENERGY, INC.

Crude oil, Natural Gas and NGLs Sales

The following tables present crude oil, natural gas and NGLs production and weighted-average sales price from continuing operations:

Production by Operating Region	Three Months Ended June 30, 2013	2012	Percentage Change	Six Months Ended June 30, 2013	2012	Percentage Change
Crude oil (MBbls)						
Western - Wattenberg Field	605.5	439.7	37.7 %	1,256.2	981.0	28.1 %
Eastern - Appalachian Basin	12.2	2.6	*	29.8	5.7	*
Total	617.7	442.3	39.7 %	1,286.0	986.7	30.3 %
Natural gas (MMcf)						
Western - Wattenberg Field	2,916.2	2,116.3	37.8 %	5,891.7	4,514.7	30.5 %
Eastern - Appalachian Basin	1,595.3	1,462.7	9.1 %	3,169.6	2,948.8	7.5 %
Total	4,511.5	3,579.0	26.1 %	9,061.3	7,463.5	21.4 %
NGLs (MBbls)						
Western - Wattenberg Field	275.2	191.6	43.6 %	513.5	418.8	22.6 %
Eastern - Appalachian Basin	1.3	—	*	1.3	—	*
Total	276.5	191.6	44.3 %	514.8	418.8	22.9 %
Crude oil equivalent (MBoe)						
Western - Wattenberg Field	1,366.7	984.0	38.9 %	2,751.7	2,152.2	27.9 %
Eastern - Appalachian Basin	279.4	246.4	13.4 %	559.4	497.2	12.5 %
Total	1,646.1	1,230.4	33.8 %	3,311.1	2,649.4	25.0 %

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

Average Sales Price by Operating Region (excluding gain (loss) on derivatives)	Three Months Ended June 30, 2013	2012	Percentage Change	Six Months Ended June 30, 2013	2012	Percentage Change
Crude oil (per Bbl)						
Western - Wattenberg Field	$87.31	$88.09	(0.9)%	$87.09	$90.70	(4.0)%
Eastern - Appalachian Basin	87.74	67.39	30.2%	88.95	84.22	5.6%
Weighted-average price	87.32	87.97	(0.7)%	87.13	90.67	(3.9)%
Natural gas (per Mcf)						
Western - Wattenberg Field	$3.71	$2.04	81.9%	$3.36	$2.37	41.8%
Eastern - Appalachian Basin	3.93	2.06	90.8%	3.58	2.25	59.1%
Weighted-average price	3.79	2.05	84.9%	3.44	2.33	47.6%
NGLs (per Bbl)						
Western - Wattenberg Field	$23.46	$26.65	(12.0)%	$26.72	$27.39	(2.4)%
Eastern - Appalachian Basin	41.21	—	*	41.21	—	*
Weighted-average price	23.55	26.65	(11.6)%	26.76	27.39	(2.3)%
Crude oil equivalent (per Boe)						
Western - Wattenberg Field	$51.32	$48.93	4.9%	$51.94	$51.65	0.6%
Eastern - Appalachian Basin	26.47	12.95	104.4%	25.13	14.33	75.4%

Weighted-average price	47.10	41.73	12.9%	47.41	44.65	6.2%

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

Table of contents
PDC ENERGY, INC.

For the three and six months ended June 30, 2013, crude oil, natural gas and NGLs sales revenue increased compared to the three and six months ended June 30, 2012 due to the following (in millions):

	June 30, 2013	
	Three Months Ended	Six Months Ended
Increase in production	$19.6	$33.5
Increase in average natural gas price	7.8	10.1
Decrease in average NGL price	(0.8)	(0.3)
Decrease in average crude oil price	(0.4)	(4.6)
Total increase in crude oil, natural gas and NGLs sales revenue	$26.2	$38.7

Crude Oil, Natural Gas and NGLs Pricing. Our results of operations depend upon many factors, particularly the price of crude oil, natural gas and NGLs and our ability to market our production effectively. Crude oil, natural gas and NGLs prices are among the most volatile of all commodity prices. These price variations can have a material impact on our financial results and capital expenditures.

Natural gas prices vary by region and locality, depending upon the distance to markets, availability of pipeline capacity and supply and demand relationships in that region or locality. The price we receive for our natural gas produced in our Western operating region is based on CIG prices, while natural gas produced in our Eastern operating region is based on NYMEX pricing. Our NGL price is mainly based on prices from the Conway hub in Kansas where our Wattenberg production is marketed. Crude oil pricing is predominately driven by the physical market, supply and demand, the financial markets and national and international politics. The majority of our crude oil is sold on a calendar-year basis at a fixed differential to NYMEX pricing.

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 as 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.

During the spring and summer of 2012 and the latter part of the second quarter of 2013, and to a lesser extent in some other recent periods, our Wattenberg Field production has been adversely impacted by increasing line pressures on the gathering system operated by our third-party service provider. The continued acceleration of industry drilling activity, combined with higher temperatures, have resulted in reduced system compressor efficiency and increased line pressures. The curtailments that have occurred to date in 2013 are consistent with what we expected to occur during this period. We, and other operators in the field, are working closely with our primary midstream provider in the Wattenberg Field who is implementing a multi-year facility expansion capable of significantly increasing long-term gathering and processing capacity. Initial system improvements have already been implemented with the startup of a new field compressor station, as well as installation and commissioning of gas bypass facilities at two gas processing plants in May and June of 2013. These projects increased midstream system capacity and have helped to mitigate the impact of increased production volumes on system pressures. We expect reduced line pressures to substantially benefit us in late 2013, concurrent with the startup of the LaSalle gas plant and associated field compressor stations. Like most producers, we rely on our third-party midstream service providers to construct compression, gathering and processing facilities to keep pace with our production growth. As a result, the timing and availability of these facilities is beyond our control.

Production Costs

Production costs include lease operating expenses, production taxes and certain production and engineering staff-related overhead costs, as well as other costs to operate wells and pipelines as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(in millions)			
Lease operating expenses	$8.2	$6.9	$15.6	$13.8
Production taxes	5.3	3.7	10.7	8.2
Cost of well operations, overhead and other production expenses	2.7	1.8	5.7	3.3
Total production costs	$16.2	$12.4	$32.0	$25.3
Total production costs per Boe	$9.83	$10.06	$9.67	$9.55

Lease operating expenses. The $1.3 million increase in lease operating expenses during the three months ended June 30, 2013 compared to the three months ended June 30, 2012 was primarily due to an increase of $0.5 million for maintenance related to wells acquired in the June 2012 Merit acquisition, an increase of $0.5 million for transportation expense related to Marcellus Shale production, an increase of $0.4 million for the rental of additional compressors used to accommodate high line pressures in the Wattenberg Field and an increase of $0.4 million in additional wages and employee benefits. These increases were partially offset by a $0.6 million decrease in expense due to a reduction in the number of workover projects performed during the three months ended June 30, 2013 as compared to the three months ended June 30, 2012. The $1.8 million increase in lease operating expenses during the six months ended June 30, 2013 as compared to the six months ended June 30, 2012 was primarily due to an increase of $0.6 million for the rental of additional compressors used to accommodate high line pressures in the Wattenberg Field, an increase of $0.6 million for transportation expense related to Marcellus Shale production, an increase of $0.5 million in additional wages and employee benefits and an increase of $0.4 million in general maintenance and environmental remediation projects. These increases were partially offset by a $0.3 million decrease in expense due to a reduction in the number of workover projects performed during the six months ended June 30, 2013 as compared to the six months ended June 30, 2012.

Production taxes. Production taxes are directly related to crude oil, natural gas and NGL sales. The $1.6 million, or 43.2%, increase in production taxes for the three months ended June 30, 2013 compared to the three months ended June 30, 2012, was primarily related to the 51.0% increase in crude oil, natural gas and NGL sales. Similarly, the $2.5 million, or 30.5%, increase in production taxes for the six months ended June 30, 2013 compared to the six months ended June 30, 2012 was primarily related to the 32.7% increase in crude oil, natural gas and NGL sales.

Overhead and other production expenses. Overhead and other production expenses increased $0.9 million for the three months ended June 30, 2013 as compared to the three months ended June 30, 2012. The increase consisted of a $0.7 million increase in transportation expense due to unutilized firm transportation and a $0.2 million increase in various other operating costs. Overhead and other production expenses increased $2.4 million for the six months ended June 30, 2013 as compared to the six months ended June 30, 2012. The increase consisted of a $1.2 million increase in transportation expense due to unutilized firm transportation, a $0.4 million increase in wages and employee benefits, a $0.3 million increase in rental equipment and a $0.5 million increase in various other operating costs.

Commodity Price Risk Management, Net

Commodity price risk management, net, includes realized gains and losses and unrealized changes in the fair value of derivative instruments related to our crude oil and natural gas 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 of Financial Instruments, and Note 4, Derivative Financial Instruments, to our condensed consolidated financial statements included elsewhere in this report for additional details of our derivative financial instruments.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(in millions)			
Commodity price risk management gain, net:				
Realized gains (losses):				
Natural gas	$3.1	$16.0	$11.2	$28.5
Crude oil	0.8	0.2	1.2	(2.4)
Total realized gains, net	3.9	16.2	12.4	26.1
Unrealized gains (losses):				
	(3.2)	(13.5)	(17.8)	(16.0)

Reclassification of realized gains included in prior periods unrealized				
Unrealized gains for the period	24.0	36.0	7.8	40.1
Total unrealized gains (losses), net	20.8	22.5	(10.0)	24.1
Total commodity price risk management gain, net	$24.7	$38.7	$2.4	$50.2

Realized gains recognized in the three and six months ended June 30, 2013 are primarily the result of lower natural gas and crude oil spot prices at settlement compared to the respective strike price. For the three and six months ended June 30, 2013, realized gains on natural gas, exclusive of basis swaps, were $6.4 million and $18.6 million, respectively. These gains were reflective of a weighted-average strike price of $5.14 and $5.11, respectively, compared to a weighted-average settlement price of $4.08 and $3.69, respectively. These gains were offset in part by realized losses of $3.3 million and $7.4 million, respectively, on our basis swap positions as the negative basis differential between NYMEX and CIG was a weighted-average of $0.28 and $0.20, respectively, compared to a weighted-average strike price of $1.06 and $0.90, respectively. Realized gains for the three and six months ended June 30, 2013 on our crude oil positions are reflective of a weighted-average strike price of $96.89 and $96.57, respectively, compared to a weighted-average settlement price of $94.28 and $94.37, respectively.

During the three months ended June 30, 2013, unrealized gains on our crude oil and natural gas positions were $13.1 million and $10.7 million, respectively, due to the downward shift in the crude oil and natural gas forward curve. The widening of the CIG basis forward curve during the three months ended June 30, 2013 resulted in unrealized gains of $0.2 million.

Unrealized gains during the six months ended June 30, 2013 were primarily related to a downward shift in the crude oil and natural gas forward curves and their impact on the fair value of our open positions. For the six month period, unrealized gains on our crude oil and natural gas derivative positions were $6.5 million and $0.6 million, respectively. The widening of the CIG basis forward curve during the six months ended June 30, 2013 resulted in unrealized gains of $0.7 million.

During the three and six months ended June 30, 2012, realized gains on natural gas derivatives, exclusive of basis swaps, were $20.1 million and $37.1 million, 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 narrower than the strike price of the basis positions. Realized gains on crude oil derivatives were $0.2 million for the three months ended June 30, 2012 compared to realized losses of $2.4 million for the six months ended June 30, 2012.

During the three months ended June 30, 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 June 30, 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.

We use various derivative instruments to manage fluctuations in crude oil and natural gas prices. We have in place a variety of floors, collars, fixed-price swaps and basis swaps on a portion of our estimated crude oil and natural gas production. Because we sell all of our physical crude oil and natural gas at prices similar to the indexes inherent in our derivative instruments, adjusted for certain fees and surcharges stipulated in the applicable sales agreements, 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.

Natural Gas Marketing

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

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,	
	2013	2012	2013	2012
	(in millions)			
Natural gas sales revenue	$16.7	$9.0	$31.1	$19.5
Realized derivative gains (losses), net	(0.2)	0.7	—	1.5
Unrealized derivative gains (losses), net	1.6	(1.1)	0.7	(1.0)
Total sales from natural gas marketing	18.1	8.6	31.8	20.0
Costs of natural gas purchases	16.4	8.5	30.0	18.4
Realized derivative (gains) losses, net	(0.2)	0.7	(0.1)	1.5
Unrealized derivative (gains) losses, net	1.6	(1.1)	0.6	(1.0)

Other	0.3	0.4	1.3	0.7
Total costs of natural gas marketing	18.1	8.5	31.8	19.6
Natural gas marketing contribution margin	$—	$0.1	$—	$0.4

Natural gas sales revenue and cost of natural gas purchases increased in the three and six months ended June 30, 2013 compared to the three and six months ended June 30, 2012 primarily due to natural gas prices increasing by approximately 78.7% and 48.1%, respectively, slightly offset in part by small decreases in volume.

Derivative instruments related to natural gas marketing include both physical and cash-settled derivatives. We offer fixed-price derivative contracts for the purchase or sale of physical natural gas and enter into cash-settled derivative positions with counterparties in order to offset those same physical positions.

Table of contents
PDC ENERGY, INC.

Exploration Expense

The following table presents the major components of exploration expense:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(in millions)			
Exploratory dry hole costs	$—	$0.4	$—	$0.4
Geological and geophysical costs	—	0.7	0.5	1.6
Operating, personnel and other	1.4	1.3	2.6	2.2
Total exploration expense	$1.4	$2.4	$3.1	$4.2

Exploratory dry hole costs. Exploratory dry hole costs during the three months ended June 30, 2012 were related to the unsuccessful testing of an exploratory zone in two existing Wattenberg Field wells.

Geological and geophysical costs. The decrease during the three and six months ended June 30, 2013 of $0.7 million and $1.1 million, respectively, compared to the three and six months ended June 30, 2012 is primarily related to costs associated with a decrease in PDCM's geological and seismic testing of the Marcellus Shale in the Appalachian Basin and PDC's reservoir studies in the Utica Shale.

Operating, personnel and other. The $0.4 million increase during the six months ended June 30, 2013 compared to the six months ended June 30, 2012 is mainly attributable to payroll and employee benefits in the exploration division as a result of increased employee headcount for the Utica Shale operations.

Impairment of Crude oil and Natural Gas Properties

The following table sets forth the major components of our impairments of crude oil and natural gas properties expense:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(in millions)			
Impairment of proved properties	$—	$—	$45.0	$—
Impairment of individually significant unproved properties	0.7	0.2	0.8	0.3
Amortization of individually insignificant unproved properties	0.8	0.2	2.1	0.6
Total impairment of crude oil and natural gas properties	$1.5	$0.4	$48.0	$0.9

Impairment of proved properties. In the first quarter of 2013, we recognized an impairment charge of approximately $45 million related to all of our shallow upper Devonian (non-Marcellus Shale) Appalachian Basin producing properties located in West Virginia and Pennsylvania owned directly by us, as well as through our proportionate share of PDCM and our affiliated partnerships. The impairment charge represented the excess of the carrying value of the assets to the estimated fair value, less cost to sell. The fair value of the assets was determined based upon estimated future cash flows from unrelated third-party bids, a Level 3 input. See Note 12, Assets Held for Sale, Divestitures and Discontinued Operations, for additional information regarding these properties. It is not certain that these properties will be sold.

Impairment of individually significant unproved properties: The $0.5 million increase during the three and six months ended June 30, 2013 compared to the three and six months ended June 30, 2012 is primarily related to non-Utica leases in Ohio that were determined to be impaired in June 2013.

Amortization of individually insignificant unproved properties. The $0.6 million and $1.5 million increase during the three and six months ended June 30, 2013, respectively, compared to the three and six months ended June 30, 2012 is primarily related to an increase in leases not held by production, primarily in the Utica Shale.

General and Administrative Expense

General and administrative expense increased $1.4 million to $15.8 million for the three months ended June 30, 2013 compared to $14.4 million for the three months ended June 30, 2012. The increase was primarily due to increased stock-based compensation of $2 million due to expanding employee participation in our equity incentive program and certain award modifications and a $0.3 million increase in payroll and employee benefits, partially offset by a decrease in professional, consulting and legal costs of $1.1 million.

Table of contents
PDC ENERGY, INC.

General and administrative expense increased $1.8 million to $30.9 million for the six months ended June 30, 2013 compared to $29.1 million for the six months ended June 30, 2012. The increase was primarily due to increased stock-based compensation of $2.7 million due to expanding employee participation in our equity incentive program and certain award modifications and a $0.9 million increase in payroll and employee benefits, partially offset by a decrease in professional, consulting and legal costs of $1.7 million.

Depreciation, Depletion and Amortization Expense

Crude oil and Natural gas properties. Depreciation, depletion and amortization ("DD&A") expense related to crude oil and natural gas properties is directly related to proved reserves and production volumes. DD&A expense related to crude oil and natural gas properties was $26.6 million and $53.3 million for the three and six months ended June 30, 2013, respectively, compared to $22.7 million and $49.5 million for the three and six months ended June 30, 2012, respectively. The increase in our production for the three and six months ended June 30, 2013 contributed $7.7 million and $12.4 million to these increases, respectively, while lower weighted-average depreciation, depletion and amortization rates resulted in a decrease in depreciation, depletion and amortization expense of $3.8 million and $8.6 million for each of the three and six months ended June 30, 2012, respectively.

The following table presents our DD&A expense rates for crude oil and natural gas properties:

	Three Months Ended June 30,		Six Months Ended June 30,	
Operating Region/Area	2013	2012	2013	2012
	(per Boe)			
Western				
Wattenberg Field	$17.91	$20.00	$17.45	$20.36
Eastern				
Marcellus Shale and other	7.49	12.29	9.47	11.45
Total weighted-average	16.14	18.45	16.10	18.69

Non-crude oil and natural gas properties. Depreciation expense for non-crude oil and natural gas properties was $1.2 million and $2.4 million for the three and six months ended June 30, 2013 compared to $1.1 million and $2.2 million for the three and six months ended June 30, 2012, respectively.

Interest Expense

Interest expense increased $3.0 million to $13.1 million for the three months ended June 30, 2013 compared to $10.1 million for the three months ended June 30, 2012. The increase is primarily related to $9.7 million of interest expense resulting from the issuance of $500 million 7.75% senior notes due 2022 in October 2012. Partially offsetting this increase were decreases of $6.3 million related to the November 2012 redemption of previously-outstanding 12% senior notes due 2018 and $0.5 million in the amortization of debt issuance costs.

Interest expense increased $5.9 million to $26.4 million for the six months ended June 30, 2013 compared to $20.5 million for the six months ended June 30, 2012. The increase is primarily related to $19.6 million of interest expense resulting from the issuance of $500 million 7.75% senior notes due 2022 in October 2012. Partially offsetting this increase were decreases of $12.6 million related to the November 2012 redemption of previously-outstanding 12% senior notes due 2018, $0.6 million in the amortization of debt issuance costs and $0.7 million as a result of lower average borrowings on our revolving credit facility during the six months ended June 30, 2013 as compared to the six months ended June 30, 2012.

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 for the three and six months ended June 30, 2013 compared to the three and six months ended June 30, 2012. Because the estimate of full-year income may change from quarter to quarter, the effective tax rate for any particular quarter may not have a meaningful relationship to pre-tax income or loss for the quarter or the current estimated annual effective tax rate. In addition, the different effects of permanent tax adjustments when comparing interim loss periods with interim income periods may make the effective tax rate comparison for the three- and six-month periods less meaningful.

Discontinued Operations

In February 2013, we entered into a purchase and sale agreement with certain affiliates of Caerus, pursuant to which we agreed to sell to Caerus our Piceance Basin, NECO and certain other non-core Colorado oil and gas properties, leasehold mineral interests and related assets. On June 18, 2013, this divestiture was completed with total consideration of approximately $177.6 million, subject to customary post-closing adjustments, with an additional $17.0 million paid to our non-affiliated investor partners. The sale resulted in a pre-tax loss of $1.1 million. The effective date of the transaction was January 1, 2013. Following the sale to Caerus, we do not have significant continuing involvement in the operations of, or cash flows from, the Piceance Basin and NECO oil and gas properties. Accordingly, the results of operations related to these assets have been separately reported as discontinued operations in the condensed consolidated statement of operations for all periods presented. The sale of our other non-core Colorado oil and gas properties did not meet the requirements to be accounted for as discontinued operations.

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. 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, the Permian Basin assets. Accordingly, the results of operations related to these assets have been separately reported as discontinued operations in the condensed consolidated statement of operations for the three and six month periods ended June 30, 2012.

See Note 12, Assets Held for Sale, Divestitures and Discontinued Operations, to the accompanying condensed consolidated financial statements included elsewhere in this report for additional information regarding the sale of our Piceance Basin, NECO and other non-core Colorado oil and gas properties and the divestiture of our Permian assets.

The table below presents production data related to the assets that have been divested and that are classified as discontinued operations:

	Three Months Ended June 30,		Six Months Ended June 30,	
Discontinued Operations	2013	2012	2013	2012
Production				
Crude oil (MBbls)	7.2	9.1	14.1	59.0
Natural gas (MMcf)	3,059.3	4,095.2	6,643.4	8,625.0
NGLs (MBbl)	—	0.3	—	14.9
Crude oil equivalent (MBoe)	517.1	691.9	1,121.3	1,511.4

Net Income (Loss)/Adjusted Net Income (Loss)

Net income for the three months ended June 30, 2013 and net loss for the six months ended June 30, 2013 was $19.9 million and $19.5 million, respectively, compared to net income of $12.3 million and $28.1 million for the three and six months ended June 30, 2012, respectively. Adjusted net income, a non-U.S. GAAP financial measure, for the three months ended June 30, 2013 was $7.0 million and adjusted net loss for the six months ended June 30, 2013 was $13.4 million, compared to an adjusted net loss of $1.7 million for the three months ended June 30, 2012 and adjusted net income of $13.2 million for the six months ended June 30, 2012. The quarter-over-quarter changes in net income are discussed above, with the most significant changes related to the increase in crude oil, natural gas and NGL sales and income from discontinued operations and the decrease in income from commodity price risk management activities. The year-over-year change in net income (loss) are discussed above, with the most significant changes related to the increase in crude oil, natural gas and NGL sales and impairment of crude oil and natural gas properties and the decrease in income from commodity price risk management activities. These same reasons for change similarly impacted adjusted net income (loss), with the exception of the unrealized derivative gains and losses on derivatives, adjusted for taxes, as these amounts are not included in the total. See Reconciliation of Non-U.S. GAAP Financial Measures, below, for a more detailed discussion of this non-U.S. GAAP financial measure.

Financial Condition, Liquidity and Capital Resources

Historically, our primary sources of liquidity have been cash flows from operating activities, our revolving credit facility, proceeds raised in debt and equity markets and asset monetization transactions. For the six months ended June 30, 2013, our primary sources of liquidity were the proceeds received from the sale of properties and equipment and acquisition adjustments of approximately $180.9 million and net cash flows from operating activities of $42.0 million.

Our primary source of cash flows from operating activities is the sale of crude oil, natural gas and NGLs. Fluctuations in our operating cash flows are substantially driven by commodity prices and changes in our production volumes. Commodity prices have historically been volatile and we manage this volatility through our 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 three years or less, our debt covenants limit us from entering into hedges that would exceed 85% 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 three years, but no more than our designated maximum maturity, our debt covenants limit our holdings to 85% of our expected future production from 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 revolving credit facility. At June 30, 2013, we had a working capital surplus of $9.4 million compared to a deficit of $31.4 million at December 31, 2012.

We ended June 2013 with cash and cash equivalents of $43.2 million and availability under our revolving credit facility and our proportionate share of PDCM's credit facility of $435.3 million, for a total liquidity position of $478.5 million, compared to $398.6 million at December 31, 2012. The increase in liquidity of $79.9 million, or 20.0%, was primarily attributable to $180.9 million received from the sale of properties and equipment and acquisition adjustments and cash flows provided by operating activities of $42.0 million, offset in part by capital expenditures of $139.5 million during the six months ended June 30, 2013. With our current liquidity position and expected cash flows from operations, we believe that we have sufficient capital to fund operations.

Capital Expenditures

We establish a capital budget annually based upon our development and exploration opportunities, liquidity position and expected cash flows from operating activities. 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 March 2013, our Board of Directors approved our current 2013 capital budget of $387 million, excluding our share of PDCM's capital budget. Based on our budget, we expect to allocate $280 million to be invested in the Wattenberg Field, where we expect to drill a total of 69 horizontal wells in the liquid-rich Niobrara and Codell formations during 2013. We expect to allocate approximately $96 million to drilling, leasing and completion activity in the Utica Shale, where we expect to maintain a one-rig drilling program throughout 2013 and expect to drill a total of 11 horizontal wells. PDCM's 2013 capital budget is $114 million, of which $57 million represents our share, and is expected to be funded by PDCM's operating activities, proceeds from divestitures and additional borrowings. PDCM's capital budget for 2013 includes funding for the drilling of 15 gross horizontal wells.

Because crude oil and natural gas production from a well declines rapidly in the first few years of production, we need to continue to commit significant amounts of capital in order to maintain and grow our production and replace our reserves. 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 revolving credit facility as the sources for funding our capital expenditures. We would not be able to maintain our current level of crude oil, natural gas and NGLs production and cash flows from operating activities if capital markets were unavailable, commodity prices were to become depressed and/or the borrowing base under our revolving credit facility was significantly reduced. The occurrence of such an event may result in our election to defer a substantial portion of our planned capital expenditures 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 revolving credit facility and to obtain proceeds from the issuance of debt and equity securities. We cannot, however, assure this will continue to be the case in the future. We continue to monitor market conditions and circumstances and their potential impact on each of our revolving credit facility lenders. Our $450 million revolving credit facility borrowing base is subject to a redetermination each May and November, based upon a quantification of our proved reserves at each June 30 and December 31, respectively. Our next scheduled redetermination is in November 2013. While we expect to continue to add producing reserves through our drilling operations, these reserve additions could be offset by other factors including, among other things, a significant decrease in commodity prices.

In January 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 or 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 market conditions to be favorable.

Our revolving credit facility contains financial maintenance covenants. The covenants require that we maintain: (i) total debt of less than 4.25 times earnings before interest, taxes, depreciation, depletion and amortization, unrealized derivative gains (losses), exploration expense, gains (losses) on sales of assets and other non-cash, extraordinary or non-recurring gains (losses) ("EBITDAX") and (ii) an adjusted current ratio of at least 1.0 to 1.0. Our adjusted current ratio is adjusted by eliminating the impact on our current assets and liabilities of recording the fair value of crude oil and natural gas derivative instruments. Additionally, available borrowings under our revolving credit facility are added to the current asset calculation and the current portion of our revolving credit facility debt is eliminated from the current liabilities calculation. At June 30, 2013, we were in compliance with all debt covenants with a 2.8 times debt to EBITDAX ratio and a 4.0 to 1.0 current ratio. We expect to remain in compliance throughout the next year.

The indenture governing our 7.75% senior notes due 2022 contains customary 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, redeem or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) restrict the payment of dividends or other payments by restricted subsidiaries to us, (e) create liens that secure debt, (f) enter into transactions with affiliates and (g) merge or consolidate with another company. At June 30, 2013, we were in compliance with all covenants 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.

Table of contents
PDC ENERGY, INC.

Cash Flows

Operating Activities. Our net cash flows from operating activities are 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 by $27.7 million for the six months ended June 30, 2013 compared to the six months ended June 30, 2012. The decrease in cash provided by operating activities was primarily due to changes in assets and liabilities of $47.2 million related to the timing of cash payments and receipts, the decrease in realized derivative gains of $13.7 million and the increase in production costs of $6.7 million. The decrease was offset in part by the increase in crude oil, natural gas and NGLs sales of $38.7 million. The key components for the changes in our cash flows provided by operating activities are described in more detail in Results of Operations above.

Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased $19.5 million during the six months ended June 30, 2013 compared to the six months ended June 30, 2012. The increase was primarily due to the same factors mentioned above for changes in cash flows provided by operating activities, without regard to timing of cash payments and receipts of assets and liabilities. Adjusted EBITDA, a non-U.S. GAAP financial measure, decreased slightly by $1.7 million during the six months ended June 30, 2013 compared to the six months ended June 30, 2012, primarily due to the same factors mentioned above for changes in adjusted cash flows from operations, in addition to the $23.4 million decrease in the gain on sale of properties and equipment. See Reconciliation of Non-U.S. GAAP Financial Measures, below, for a more detailed discussion of non-U.S. GAAP financial measures.

Investing Activities. Cash flows from investing activities primarily consist of the acquisition, exploration and development of crude oil and natural gas properties, net of dispositions of crude oil and natural gas properties. During the six months ended June 30, 2013, our drilling program consisted of three drilling rigs operating in the oil- and liquid-rich horizontal Niobrara and Codell plays in our Wattenberg Field (the third rig commenced operations in May, 2013), one rig in the Utica shale play and one rig in the Marcellus Shale. Net cash from investing activities of $41.4 million during the six months ended June 30, 2013 was primarily related to $180.9 million received from the sale of properties and equipment and acquisition adjustments, offset in part by cash utilized for our drilling operations of $139.5 million.

Financing Activities. Net cash from financing activities for the six months ended June 30, 2013 decreased significantly compared to the six months ended June 30, 2012. Net cash from financing activities for the six months ended June 30, 2013 was primarily related to our utilization of proceeds provided from the divestiture of our Piceance Basin and NECO assets in June 2013 to pay down amounts borrowed under our revolving credit facility and partially fund our capital expenditures. It was therefore not necessary to draw on our revolving bank credit facility.

Drilling Activity

The following table presents our net developmental and exploratory drilling activity. There is no correlation between the number of productive wells completed during any period and the aggregate reserves attributable to those wells. Productive wells consist of wells spudded, turned-in-line and producing during the period. In-process wells represent wells that have been spudded, drilled and are waiting to be completed and/or for gas pipeline connection during the period.

Net Drilling Activity								
Three Months Ended June 30,				Six Months Ended June 30,				
2013		2012		2013			2012	
Productive	In-Process	Productive	In-Process	Productive	In-Process	Dry	Productive	In-Process

Operating Region/Area									
Development Wells									
Western	2.5	14.0	1.4	4.4	11.0	15.5	0.1	6.1	5.6
Eastern	—	1.5	—	—	—	3.5	—	1.5	—
Total development wells	2.5	15.5	1.4	4.4	11.0	19.0	0.1	7.6	5.6
Exploratory Wells									
Eastern	—	2.8	—	2.0	—	4.3	—	—	2.0
Total exploratory wells	—	2.8	—	2.0	—	4.3	—	—	2.0
Total drilling activity	2.5	18.2	1.4	6.4	11.0	23.2	0.1	7.6	7.6

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 2012 Form 10-K filed with the SEC on February 27, 2013 and in our Current Report on Form 8-K filed with the SEC on June 28, 2013.

Table of contents

Commitments and Contingencies

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

Recent Accounting Standards

See Note 2, Summary of Significant Accounting Policies, to the accompanying condensed consolidated financial statements included elsewhere 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 2012 Form 10-K filed with the SEC on February 27, 2013 and in our Current Report on Form 8-K filed with the SEC on June 28, 2013.

Reconciliation of Non-U.S. GAAP Financial Measures

Adjusted cash flows from operations. We define adjusted cash flows from operations as the cash flows earned or incurred from operating activities, without regard to changes in operating assets and liabilities. We believe it is important to consider adjusted cash flows from operations, as well as cash flows from operations, as we believe it often provides more transparency into what drives the changes in our operating trends, such as production, prices, operating costs and related operational factors, without regard to whether the related asset or liability was received or paid during the same period. We also use this measure because the timing of cash received from our assets, cash paid to obtain an asset or payment of our obligations has been only a timing issue from one period to the next as we have not had accounts receivable collection problems, nor been unable to purchase assets or pay our obligations. See the condensed consolidated statements of cash flows in the accompanying condensed consolidated financial statements included elsewhere in this report.

Adjusted net income (loss). We define adjusted net income (loss) as net income (loss) plus unrealized derivative losses, less unrealized derivative gains, each adjusted for tax effect. We believe it is important to 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 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 crude oil and natural gas properties, depreciation, depletion and amortization, and accretion of asset retirement obligations, less unrealized derivative gain. Adjusted EBITDA is not a measure of financial performance or liquidity under U.S. GAAP and should be considered in addition to, not as a substitute for, net income (loss), nor as an indicator of cash flows reported in accordance with U.S. GAAP. Adjusted EBITDA includes certain non-cash costs incurred by the Company and does not take into account changes in operating assets and liabilities. Other companies in our industry may calculate Adjusted EBITDA differently than we do, limiting its usefulness as a comparative measure. We believe adjusted EBITDA is relevant because it is a measure of our operational and financial performance, as well as a measure of our liquidity, and is used by our management, investors, commercial banks, research analysts and others to analyze such things as:

- our operating performance and return on capital as compared to our peers;
- the financial performance of our assets and our valuation without regard to financing methods, capital structure or historical cost basis;
- our ability to generate sufficient cash to service our debt obligations; and
- the viability of acquisition opportunities and capital expenditure projects, including the related rate of return.

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,	
	2013	2012	2013	2012
	(in millions)			
Adjusted cash flows from operations:				
Adjusted cash flows from operations	$46.4	$29.5	$98.7	$79.2
Changes in assets and liabilities	(48.6)	(4.1)	(56.7)	(9.5)
Net cash from operating activities	$(2.2)	$25.4	42.0	$69.7
Adjusted net income (loss):				
Adjusted net income (loss)	$7.0	$(1.7)	$(13.4)	$13.2
Unrealized gain (loss) on derivatives, net	20.8	22.6	(9.9)	24.1
Tax effect of above adjustments	(7.9)	(8.6)	3.8	(9.2)
Net income (loss)	$19.9	$12.3	$(19.5)	$28.1
Adjusted EBITDA to net income (loss):				
Adjusted EBITDA	$54.1	$41.5	$115.3	$117.0
Unrealized gain (loss) on derivatives, net	20.8	22.6	(9.9)	24.1
Interest expense, net	(13.1)	(10.1)	(26.4)	(20.5)
Income tax provision	(11.4)	(6.1)	10.0	(15.6)
Impairment of crude oil and natural gas properties	(1.5)	(0.3)	(48.0)	(1.0)
Depreciation, depletion and amortization	(27.8)	(34.5)	(58.0)	(74.3)
Accretion of asset retirement obligations	(1.2)	(0.8)	(2.5)	(1.6)
Net income (loss)	$19.9	$12.3	$(19.5)	$28.1
Adjusted EBITDA to net cash from operating activities:				
Adjusted EBITDA	$54.1	$41.5	$115.3	$117.0
Interest expense, net	(13.1)	(10.1)	(26.4)	(20.5)
Exploratory dry hole costs	0.1	0.4	0.1	0.4
Stock-based compensation	4.4	2.0	7.0	3.9
Amortization of debt discount and issuance costs	1.7	1.9	3.4	3.5
(Gain) loss on sale of properties and equipment	1.1	(1.8)	1.0	(22.3)
Other	(1.9)	(4.4)	(1.7)	(2.8)
Changes in assets and liabilities	(48.6)	(4.1)	(56.7)	(9.5)
Net cash from operating activities	$(2.2)	$25.4	42.0	$69.7

Table of contents

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

Market-Sensitive Instruments and Risk Management

We are exposed to market risks associated with interest rate risks, commodity price risk and credit risk. 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 revolving credit facility. Our senior notes and convertible senior notes have fixed rates 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, 2013, 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, cash equivalents and restricted cash as of June 30, 2013 was $46.4 million with an average interest rate of 0.1%. The $46.4 million represents our aggregate bank balances, which includes checks issued and outstanding. Based on a sensitivity analysis of our interest bearing deposits as of June 30, 2013, it was estimated that if market interest rates would have increased or decreased by 1%, the impact on interest income for the six months ended June 30, 2013 would have been immaterial.

As of June 30, 2013, excluding the $18.7 million irrevocable standby letters of credit, we had no outstanding borrowings on our revolving credit facility and, representing our proportionate share, $36.0 million on PDCM's bank credit facility. We estimate that if market interest rates would have increased or decreased by 1%, the impact on interest expense for the six months ended June 30, 2013 would have been immaterial.

Commodity Price Risk

We are exposed to the potential risk of loss from adverse changes in the market price of crude oil, natural gas and NGLs. 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 crude oil and natural gas 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.

Table of contents
PDC ENERGY, INC.

The following table presents our derivative positions (excluding the derivative positions designated to our affiliated partnerships) related to crude oil and natural gas sales in effect as of June 30, 2013:

	Floors		Collars			Fixed-Price Swaps		CIG Basis Protection Swaps		
Commodity/ Index/ Maturity Period	Quantity (BBtu) (1)	Weighted-Average Contract Price	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted-Average Contract Price Floors	Weighted-Average Contract Price Ceilings	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted-Average Contract Price	Quantity (BBtu) (1)	Weighted-Average Contract Price	Fair Value June 30, 2013 (2) (in thousands)
Natural Gas NYMEX										
2013	697.1	$ 6.11	—	$ —	$ —	7,361.6	$4.33	7,628.4	$ (0.50)	$4,920.1
2014	—	—	—	—	—	13,447.5	4.11	3,424.0	(0.22)	2,778.7
2015	720.0	4.00	—	—	—	7,635.0	4.07	—	—	(613.6)
2016	600.0	4.25	—	—	—	7,920.0	3.89	—	—	(3,191.9)
2017	1,630	4.25	—	—	—	—	—	—	—	(33.4)
CIG										
2013	—	—	110.0	4.00	5.45	—	—	—	—	72.5
2014	—	—	—	—	—	4,828.0	4.00	—	—	1,906.4
2015	—	—	—	—	—	2,730.0	4.01	—	—	400.4
Total Natural Gas (3)	3,647.1		110.0			43,922.1		11,052.4		6,239.2
Crude Oil NYMEX										
2013	—	—	571.4	80.50	103.38	741.3	97.27	—	—	1,364.2
2014	—	—	1,032.0	82.83	102.55	2,471.0	91.43	—	—	6,052.4
2015	—	—	36.0	90.00	106.15	540.0	90.09	—	—	2,646.1
Total Crude Oil	—		1,639.4			3,752.3		—		10,062.7
Total Natural Gas and Crude Oil										$16,301.9

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

(2) Approximately 16.7% of the fair value of our derivative assets and 4.7% of our derivative liabilities were measured using significant unobservable inputs (Level 3). See Note 3, Fair Value Measurements, to the condensed consolidated financial statements included elsewhere in this report.

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, 2013	Year Ended December 31, 2012
Average Index Closing Price:		
Natural gas (per MMBtu)		
CIG	$3.51	$2.58
NYMEX	3.71	2.79
Crude oil (per Bbl)		
NYMEX	$93.02	$94.92
Average Sales Price Realized:		
Excluding realized derivative gains (losses)		
Natural gas (per Mcf)	$3.44	$2.63
Crude oil (per Bbl)	87.13	87.27

Based on a sensitivity analysis as of June 30, 2013, it was estimated that a 10% increase in natural gas and crude oil prices, inclusive of basis, over the entire period for which we have derivatives in place, would have resulted in a decrease in fair value of $59.9 million; whereas a 10% decrease in prices would have resulted in an increase in fair value of $58.9 million.

See Note 3, Fair Value of Financial Instruments, and Note 4, Derivative Financial Instruments, to our condensed consolidated financial statements included elsewhere in this report for a summary of our open derivative positions, as well as a discussion of how we determine the fair value of and account for our derivative contracts.

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 significant 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.

Our Oil and Gas Exploration and Production segment's crude oil, natural gas and NGLs sales are concentrated with a few predominately large customers. This concentrates the significance of our credit risk exposure to a small number of large customers. Amounts due to our Gas Marketing segment are from a diverse group of entities, including major upstream and midstream energy companies, financial institutions and end-users in various industries. We monitor their creditworthiness through our credit committee, which utilizes a number of qualitative and quantitative tools to assess credit risk and takes mitigative actions if deemed necessary. To date, we have had no material counterparty default losses in either of our Oil and Gas Exploration and Production or Gas Marketing segments.

Our derivative financial instruments may expose us to the credit risk of nonperformance by the instrument's contract counterparty. We primarily use financial institutions which are lenders in our revolving credit facility as counterparties for our derivative financial instruments. We monitor their creditworthiness through our credit committee which utilizes a number of qualitative and quantitative tools to assess credit risk and takes mitigative actions if deemed necessary. To date, we have had no material counterparty default losses from our derivative financial instruments. See Note 4, Derivative Financial Instruments, to our condensed consolidated financial statements included in this report for more detail on our derivative financial instruments.

Disruption in the credit markets 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, 2013, it does not consider those exposures or positions which could arise after that date. As a result, our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, our commodity price risk management strategies at the time, and interest rates and commodity prices at the time.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of June 30, 2013, 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).

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, 2013.

Changes in Internal Control over Financial Reporting

During the three months ended June 30, 2013, 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 our condensed consolidated financial statements included elsewhere 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 2012 Form 10-K. This information should be considered

Table of contents

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 2012 Form 10-K.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share
April 1 - 30, 2013	6,068	$40.82
May 1 - 31, 2013	21,128	43.26
June 1 - 30, 2013	10,067	54.68
Total second quarter purchases	37,263	45.95

(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.

Table of contents
PDC ENERGY, INC.

ITEM 6. EXHIBITS

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
10.1	Purchase and Sale Agreement by and among the Company, affiliated partnerships and certain affiliates of Caerus Oil and Gas LLC, dated February 4, 2013.	10-Q	000-07246	10.1	5/1/2013	
10.2	Amendment No. 1 to Purchase and Sale Agreement by and among the Company, affiliated partnerships and certain affiliates of Caerus Oil and Gas LLC, dated May 30, 2013.	8-K	000-07246	10.1	6/3/2013	
10.3	Third Amended and Restated Credit Agreement dated as of May 21, 2013, between the Company, as borrower and JPMorgan Chase Bank, N.A. and Wells Fargo Bank, N.A., as agents.	8-K	000-07246	10.1	5/28/2013	
10.4	Amended and Restated 2010 Long-Term Equity Compensation Plan, dated June 6, 2013					X
31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1*	Certifications by Chief Executive Officer and Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.					
101.INS*	XBRL Instance Document					
101.SCH*	XBRL Taxonomy Extension Schema Document					
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document					
101.DEF*						

	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Furnished herewith.

Table of contents
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 1, 2013

/s/ James M. Trimble
James M. Trimble
Chief Executive Officer and President
(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)