PDC ENERGY, INC.
Form 10-Q
August 08, 2014
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

T QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2014

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: 35,870,665 shares of the Company's Common Stock ($0.01 par value) were outstanding as of July 18, 2014.

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act") and Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") regarding our business, financial condition, results of operations and prospects. All statements other than statements of historical facts included in and incorporated by reference into this report are "forward-looking statements" within the meaning of the safe harbor provisions of the United States ("U.S.") Private Securities Litigation Reform Act of 1995. Words such as expects, anticipates, intends, plans, believes, seeks, estimates and similar expressions or variations of such words are intended to identify forward-looking statements herein. These statements relate to, among other things: closing of the proposed PDC Mountaineer, LLC ("PDCM") divestiture; use of expected proceeds from such divestiture; estimated crude oil, natural gas and natural gas liquids (“NGLs”) reserves; future production (including the components of such production), sales, expenses, cash flows and liquidity; our evaluation method of our customers' and derivative counterparties' credit risk is appropriate; anticipated capital projects, expenditures and opportunities; future exploration, drilling and development activities; our drilling programs and number of locations; the effect of additional midstream facilities and services; availability of sufficient funding for our 2014 capital program and sources of that funding, including PDCM; expected 2014 capital budget allocations; acquisitions of additional acreage and other future transactions; the impact of high line pressures and our inability to control the timing and availability of additional facilities going forward; widening of the NYMEX differential through 2014 at our two primary sales hubs primarily due to current oversupply in the Appalachian region; compliance with debt covenants; expected funding sources for conversion of our 3.25% convertible senior notes due 2016; impact of litigation on our results of operations and financial position; our ability to recoup costs incurred to remediate environmental issues that occurred as a result of a mechanical failure on a Utica Shale horizontal well; effectiveness of our derivative program in providing a degree of price stability; that we do not expect to pay dividends in the foreseeable future; our expected tax liability for uncertain positions to decrease to zero in the next 12 months; 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:

- potential impediments to completing the proposed PDCM divestiture on the expected timeframe or at all, or greater than expected purchase price adjustments;
- changes in worldwide production volumes and demand, including economic conditions that might impact demand;
- volatility of commodity prices for crude oil, natural gas and NGLs;
- 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, natural gas and NGLs 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 being greater than expected;
- timing and extent of our success in discovering, acquiring, developing and producing reserves;

- our ability to secure leases, drilling rigs, supplies and services at reasonable prices;
- 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 Utica Shale, and the impact of these facilities and regional capacity on the prices we receive for our production;
- 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 within the oil and gas industry;
- availability and cost of capital;
- reductions in the borrowing base under our revolving credit facility;
- 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;
- 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, 2013 ("2013

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Form 10-K"), filed with the U.S. Securities and Exchange Commission ("SEC") on February 20, 2014, 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 the 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 PDCM, a joint venture currently owned 50% each by PDC and Lime Rock Partners, LP. 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.

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PART I - FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

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

	June 30, 2014	December 31, 2013
Assets		
Current assets:		
Cash and cash equivalents	$40,357	$193,243
Restricted cash	49	2,214
Accounts receivable, net	116,928	94,085
Accounts receivable affiliates	6,424	6,614
Fair value of derivatives	785	2,572
Deferred income taxes	44,118	22,374
Prepaid expenses and other current assets	4,907	4,711
Total current assets	213,568	325,813
Properties and equipment, net	1,828,721	1,656,230
Fair value of derivatives	1,158	5,601
Other assets	42,978	37,559
Total Assets	$2,086,425	$2,025,203
Liabilities and Shareholders' Equity		
Liabilities		
Current liabilities:		
Accounts payable	$107,897	$109,555
Accounts payable affiliates	—	41
Production tax liability	25,259	23,421
Fair value of derivatives	50,838	15,515
Funds held for distribution	40,411	32,578
Current portion of long-term debt	106,921	—
Accrued interest payable	9,182	9,251
Other accrued expenses	40,827	23,059
Total current liabilities	381,335	213,420
Long-term debt	562,000	656,990
Deferred income taxes	116,948	118,767
Asset retirement obligation	38,911	39,872
Fair value of derivatives	23,415	3,015
Other liabilities	20,545	25,545
Total liabilities	1,143,154	1,057,609
Commitments and contingent liabilities		
Shareholders' equity		
Preferred shares - par value $0.01 per share, 50,000,000 shares authorized, none issued	—	—
Common shares - par value $0.01 per share, 150,000,000 authorized, 35,857,560 and 35,675,656 issued as of June 30, 2014	359	357

and December 31, 2013, respectively		
Additional paid-in capital	681,019	674,211
Retained earnings	262,953	293,267
Treasury shares - at cost, 18,580 and 5,508 as of June 30, 2014 and December 31, 2013, respectively	(1,060)	(241)
Total shareholders' equity	943,271	967,594
Total Liabilities and Shareholders' Equity	$2,086,425	$2,025,203

See accompanying Notes to Condensed Consolidated Financial Statements

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PDC ENERGY, INC.
Condensed Consolidated Statements of Operations
(unaudited; in thousands, except per share data)

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Revenues				
Crude oil, natural gas and NGLs sales	$139,924	$77,537	$269,768	$156,976
Sales from natural gas marketing	22,415	18,079	49,352	31,749
Commodity price risk management gain (loss), net	(53,411)	24,724	(80,566)	2,369
Well operations, pipeline income and other	544	965	1,180	2,037
Total revenues	109,472	121,305	239,734	193,131
Costs, expenses and other				
Production costs	26,754	16,176	47,958	32,034
Cost of natural gas marketing	22,428	18,065	49,298	31,801
Exploration expense	277	1,437	584	3,126
Impairment of crude oil and natural gas properties	938	1,502	1,917	47,961
General and administrative expense	40,665	15,783	64,277	30,898
Depreciation, depletion, and amortization	53,743	27,800	100,382	55,749
Accretion of asset retirement obligations	855	1,172	1,716	2,320
(Gain) loss on sale of properties and equipment	(363)	(9)	362	(47)
Total cost, expenses and other	145,297	81,926	266,494	203,842
Income (loss) from operations	(35,825)	39,379	(26,760)	(10,711)
Interest expense	(13,060)	(13,089)	(25,890)	(26,446)
Interest income	152	3	403	3
Income (loss) from continuing operations before income taxes	(48,733)	26,293	(52,247)	(37,154)
Provision for income taxes	20,546	(9,791)	21,933	12,701
Income (loss) from continuing operations	(28,187)	16,502	(30,314)	(24,453)
Income from discontinued operations, net of tax	—	3,416	—	4,953
Net income (loss)	$(28,187)	$19,918	$(30,314)	$(19,500)
Earnings per share:				
Basic				
Income (loss) from continuing operations	$(0.79)	$0.55	$(0.85)	$(0.80)
Income from discontinued operations, net of tax	—	0.11	—	0.16
Net income (loss)	$(0.79)	$0.66	$(0.85)	$(0.64)
Diluted				
Income (loss) from continuing operations	$(0.79)	$0.53	$(0.85)	$(0.80)
Income from discontinued operations, net of tax	—	0.11	—	0.16
Net income (loss)	$(0.79)	$0.64	$(0.85)	$(0.64)
Weighted-average common shares outstanding:				
Basic	35,762	30,332	35,726	30,301
Diluted	35,762	31,014	35,726	30,301

See accompanying Notes to Condensed Consolidated Financial Statements

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

	Six Months Ended June 30,	
	2014	2013
Cash flows from operating activities:		
Net loss	$(30,314)	$(19,500)
Adjustments to net loss to reconcile to net cash from operating activities:		
Net change in fair value of unsettled derivatives	61,953	9,913
Depreciation, depletion and amortization	100,382	58,007
Impairment of crude oil and natural gas properties	1,917	47,964
Accretion of asset retirement obligation	1,716	2,481
Stock-based compensation	8,879	6,951
Loss on sale of properties and equipment	362	1,029
Amortization of debt discount and issuance costs	3,443	3,419
Deferred income taxes	(23,563)	(11,075)
Other	(90)	(476)
Changes in assets and liabilities	6,905	(56,687)
Net cash from operating activities	131,590	42,026
Cash flows from investing activities:		
Capital expenditures	(293,648)	(139,462)
Proceeds from acquisition adjustments	—	7,579
Proceeds from sale of properties and equipment	1,449	173,297
Net cash from investing activities	(292,199)	41,414
Cash flows from financing activities:		
Proceeds from revolving credit facility	17,000	227,750
Repayment of revolving credit facility	(7,000)	(267,000)
Other	(2,277)	(3,435)
Net cash from financing activities	7,723	(42,685)
Net change in cash and cash equivalents	(152,886)	40,755
Cash and cash equivalents, beginning of period	193,243	2,457
Cash and cash equivalents, end of period	$40,357	$43,212
Supplemental cash flow information:		
Cash payments for (receipts from):		
Interest, net of capitalized interest	$23,724	$25,787
Income taxes	1,800	(57)
Non-cash investing activities:		
Change in accounts payable related to purchases of properties and equipment	$(6,962)	$(8,695)
Change in asset retirement obligation, with a corresponding change to crude oil and natural gas properties, net of disposals	341	211
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

NOTE 1 - NATURE OF OPERATIONS AND BASIS OF PRESENTATION

PDC Energy, Inc. is a domestic independent exploration and production company that produces, develops, acquires and explores for crude oil, natural gas and NGLs with primary operations in the Wattenberg Field in Colorado, the Utica Shale in southeastern Ohio and the Marcellus Shale in northern West Virginia. Our operations in the Wattenberg Field are focused on the liquid-rich horizontal Niobrara and Codell plays and our Ohio operations are focused on the liquid-rich portion of the Utica Shale play. As of June 30, 2014, we owned an interest in approximately 2,900 gross wells. We are engaged in two business segments: Oil and Gas Exploration and Production and Gas Marketing.

The accompanying unaudited condensed consolidated financial statements include the accounts of PDC, our wholly owned subsidiaries, and our proportionate share of PDCM and our 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 2013 Form 10-K. Our results of operations and cash flows for the three and six months ended June 30, 2014 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. 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, 2014, we adopted changes issued by the Financial Accounting Standards Board ("FASB") regarding the accounting for income taxes. The change 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. Adoption of these changes had no impact on the condensed consolidated financial statements.

Recently Issued Accounting Standards

In April 2014, the FASB issued changes related to the criteria for determining which disposals can be presented as discontinued operations and modified related disclosure requirements. Under the new pronouncement, a discontinued operation is defined as a component of an entity that either has been disposed of or is classified as held for sale and represents a strategic shift that has a major effect on the entity's operations and financial results. These changes are to be applied prospectively for new disposals or components of an entity classified as held for sale during interim and annual periods beginning after December 15, 2014, with early adoption permitted. We are currently evaluating the impact these changes will have on our condensed consolidated financial statements.

In May 2014, the FASB and the International Accounting Standards Board ("IASB") issued their converged standard on revenue recognition that provides a single, comprehensive model that entities will apply to determine the measurement of revenue and timing of when it is recognized. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The standard outlines a five-step approach to apply the underlying principle: (a) identify the contract with the customer, (b) identify the separate performance obligations in the contract, (c) determine the transaction price, (d) allocate the transaction price to separate performance obligations and (e) recognize revenue when (or as) each performance obligation is satisfied. The revenue standard is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, and can be adopted under the full retrospective method or simplified transition method. Early adoption is not permitted. We plan to adopt the revenue standard beginning January 1, 2017 and are currently evaluating the impact these changes will have on our condensed consolidated 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. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability, and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels. The three levels of inputs that may be used to measure fair value are defined as:

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

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

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

Derivative Financial Instruments. We measure the fair value of our derivative instruments based on a pricing model that utilizes market-based inputs, including, but not limited to, the contractual price of the underlying position, current market prices, 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 and believe our valuation method is appropriate and consistent with those used by other market participants, changes in our pricing methodologies or the underlying assumptions could result in significantly different fair values.

Our fixed-price swaps, basis swaps and physical purchases are included in Level 2 and our collars, 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, 2014			December 31, 2013		
	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	$1,226	$611	$1,837	$5,325	$2,385	$7,710
Basis protection derivative contracts	104	2	106	463	—	463
Total assets	1,330	613	1,943	5,788	2,385	8,173

Liabilities:						
Commodity-based derivative contracts	66,652	7,393	74,045	17,537	988	18,525
Basis protection derivative contracts	208	—	208	5	—	5
Total liabilities	66,860	7,393	74,253	17,542	988	18,530
Net asset (liability)	$(65,530)	$(6,780)	$(72,310)	$(11,754)	$1,397	$(10,357)

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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,	
	2014	2013	2014	2013
	(in thousands)			
Fair value, net asset, beginning of period	$105	$7,663	$1,397	$13,669
Changes in fair value included in statement of operations line item:				
Commodity price risk management gain (loss), net	(7,501)	2,834	(8,896)	103
Sales from natural gas marketing	(4)	22	(26)	6
Settlements included in statement of operations line items:				
Commodity price risk management gain (loss), net	621	(2,246)	740	(5,479)
Sales from natural gas marketing	(1)	(3)	5	(29)
Income (loss) from discontinued operations, net of tax	—	(4,366)	—	(4,366)
Fair value, net asset end of period	$(6,780)	$3,904	$(6,780)	$3,904
Net change in fair value of unsettled derivatives included in statement of operations line item:				
Commodity price risk management loss, net	$(3,041)	$(1,717)	$(4,327)	$(3,652)
Sales from natural gas marketing	(2)	22	(4)	10
Total	$(3,043)	$(1,695)	$(4,331)	$(3,642)

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 value of the financial instruments included in current assets and current liabilities approximate fair value due to the short-term maturities of these instruments.

The liability associated with our non-qualified deferred compensation plan for non-employee directors may be settled in cash or shares of our common stock. The carrying value of this obligation is based on the quoted market price of our common stock, which is a Level 1 input.

The portion of our long-term debt related to our revolving credit facility, as well as our proportionate share of PDCM's credit facility and second lien term loan, approximates fair value due to the variable nature of related interest rates. We have not elected to account for the portion of our debt related to our senior notes under the fair value option; however, as of June 30, 2014, we estimate the fair value of the portion of our long-term debt related to our 3.25% convertible senior notes due 2016 to be $183.2 million, or 159.3% of par value, and the portion related to our 7.75% senior notes due 2022 to be $557.5 million, or 111.5% of par value. We determined these valuations based upon measurements of trading activity and broker and/or dealer quotes, respectively, which are published market prices, and therefore 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, 2014, taking into account the estimated likelihood of nonperformance.

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

The following table presents the counterparties that expose us to credit risk as of June 30, 2014 with regard to our derivative assets:

Counterparty Name	Fair Value of Derivative Assets (in thousands)
Wells Fargo Bank, N.A. (1)	$518
Bank of Montreal (1)	432
JP Morgan Chase Bank, N.A (1)	412
Bank of Nova Scotia (1)	298
Other lenders in our revolving credit facility	239
Various (2)	44
Total	$1,943

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(1)Major lender in our revolving credit facility. See Note 7, Long-Term Debt.
(2)Represents a total of 31 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; and

- 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, 2014, we had derivative instruments, which were comprised of collars, fixed-price swaps, basis protection swaps and physical sales and purchases, in place for a portion of our anticipated production through 2017 for a total of 53,234 BBtu of natural gas and 10,238 MBbls of crude oil. The majority of our derivative contracts are entered into at no cost to us as we hedge our anticipated production at the then-prevailing commodity market prices.

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. 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.

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The following table presents the location and fair value amounts of our derivative instruments on the condensed consolidated balance sheets as of June 30, 2014 and December 31, 2013:

Derivatives instruments:		Balance sheet line item	Fair Value June 30, 2014 (in thousands)	December 31, 2013
Derivative assets:	Current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	$519	$2,016
	Related to natural gas marketing	Fair value of derivatives	264	361
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	—	195
	Related to natural gas marketing	Fair value of derivatives	2	—
			785	2,572
	Non-current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	721	5,055
	Related to natural gas marketing	Fair value of derivatives	190	278
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	247	268
			1,158	5,601
Total derivative assets			$1,943	$8,173
Derivative liabilities:	Current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	$50,434	$15,263
	Related to natural gas marketing	Fair value of derivatives	196	247
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	207	—
	Related to natural gas marketing	Fair value of derivatives	1	5
			50,838	15,515
	Non-current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	23,255	2,782

	Related to natural gas marketing	Fair value of derivatives	160	233
			23,415	3,015
Total derivative liabilities			$74,253	$18,530

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

Condensed consolidated statement of operations line item	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(in thousands)			
Commodity price risk management income (loss), net				
Net settlements	$(10,429)	$3,903	$(18,668)	$12,374
Net change in fair value of unsettled derivatives	(42,982)	20,821	(61,898)	(10,005)
Total commodity price risk management income (loss), net	$(53,411)	$24,724	$(80,566)	$2,369
Sales from natural gas marketing				
Net settlements	$(110)	$(173)	$(586)	$28
Net change in fair value of unsettled derivatives	265	1,621	(47)	651
Total sales from natural gas marketing	$155	$1,448	$(633)	$679
Cost of natural gas marketing				
Net settlements	$149	$225	$684	$63
Net change in fair value of unsettled derivatives	(304)	(1,636)	(8)	(559)
Total cost of natural gas marketing	$(155)	$(1,411)	$676	$(496)

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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, 2014 and December 31, 2013:

As of June 30, 2014	Derivatives instruments, recorded in condensed consolidated balance sheet, gross	Effect of master netting agreements	Derivative instruments, net
	(in thousands)		
Asset derivatives:			
Derivative instruments, at fair value	$1,943	$(1,165)	$778
Liability derivatives:			
Derivative instruments, at fair value	$74,253	$(1,165)	$73,088

As of December 31, 2013	Derivatives instruments, recorded in condensed consolidated balance sheet, gross	Effect of master netting agreements	Derivative instruments, net
	(in thousands)		
Asset derivatives:			
Derivative instruments, at fair value	$8,173	$(5,623)	$2,550
Liability derivatives:			
Derivative instruments, at fair value	$18,530	$(5,623)	$12,907

NOTE 5 - PROPERTIES AND EQUIPMENT

The following table presents the components of properties and equipment, net of accumulated depreciation, depletion and amortization ("DD&A"):

	June 30, 2014	December 31, 2013
	(in thousands)	
Properties and equipment, net:		
Crude oil and natural gas properties		
Proved	$2,000,264	$1,784,466
Unproved	332,548	307,203
Total crude oil and natural gas properties	2,332,812	2,091,669

Pipelines and related facilities	21,765	21,781
Equipment and other	30,272	29,246
Land and buildings	13,620	13,617
Construction in progress	83,422	53,810
Properties and equipment, at cost	2,481,891	2,210,123
Accumulated DD&A	(653,170)	(553,893)
Properties and equipment, net	$1,828,721	$1,656,230

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(in thousands)			
Continuing operations:				
Impairment of proved properties	$—	$—	$—	$45,000
Impairment of individually significant unproved properties	—	671	—	825
Amortization of individually insignificant unproved properties	938	831	1,917	2,136
Total continuing operations	938	1,502	1,917	47,961
Discontinued operations:				
Amortization of individually insignificant unproved properties	—	—	—	3
Total discontinued operations	—	—	—	3
Total impairment of crude oil and natural gas properties	$938	$1,502	$1,917	$47,964

During the first quarter of 2013, we recognized an impairment charge of approximately $45.0 million related to all of our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin producing properties located in West Virginia and Pennsylvania previously owned directly by us, as well as through our proportionate share of PDCM. 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 rate for continuing operations for the three and six months ended June 30, 2014 was a 42.2% and 42.0% benefit on loss, respectively, compared to a 37.2% expense on income and 34.2% benefit on loss for the three and six months ended June 30, 2013, respectively. The effective tax rates for the three and six months ended June 30, 2014 are based upon a full year forecasted tax provision on income and are greater than the statutory rate primarily due to nondeductible officers' compensation, partially offset by percentage depletion deductions. 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 deductions. 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. There were no significant discrete items recorded during the three and six months ended June 30, 2014 or 2013.

As of June 30, 2014, our gross liability for unrecognized tax benefits continues to be immaterial and was unchanged from the amount recorded at December 31, 2013. We expect our remaining liability for uncertain tax positions to decrease to zero in the current year due to the expiration of the statute of limitations.

As of the date of this report, we are current with our income tax filings in all applicable state jurisdictions and are not currently under examination. We continue voluntary participation in the Internal Revenue Service's Compliance Assurance Program for the 2013 and 2014 tax years. We received a full acceptance "no change" notice from the IRS for our filed 2012 federal tax return.

NOTE 7 - LONG-TERM DEBT

Long-term debt consists of the following:

	June 30, 2014	December 31, 2013
	(in thousands)	
Senior notes:		
3.25% Convertible senior notes due 2016:		
Principal amount	$115,000	$115,000
Unamortized discount	(8,079)	(10,010)
3.25% Convertible senior notes due 2016, net of discount	106,921	104,990
7.75% Senior notes due 2022	500,000	500,000
Total senior notes	606,921	604,990
Credit facilities:		
Corporate	—	—
PDCM	47,000	37,000
Total credit facilities	47,000	37,000
PDCM second lien term loan	15,000	15,000
Total debt	668,921	656,990
Less: Current portion of long-term debt	106,921	—
Long-term debt	$562,000	$656,990

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 "Convertible Notes") in a private placement to qualified institutional buyers. Interest is payable semi-annually in arrears on each May 15 and November 15. The indenture governing the notes contains certain non-financial covenants. We allocated the gross proceeds of the Convertible Notes between the liability and equity components of the debt. The initial $94.3 million liability component was determined based upon the fair value of similar debt instruments with similar terms, excluding the conversion feature, and priced on the same day we issued the Convertible 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 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.

The Convertible Notes were convertible at the option of holders as of June 30, 2014. The conversion right was triggered on June 20, 2014, when the closing sale price of our common stock on the NASDAQ Global Select Market exceeded $55.12 (130% of the applicable conversion price) for the 20th trading day in the 30 consecutive trading days ending on June 30, 2014. In the event a holder elects to convert its note, we expect to fund any cash settlement of any such conversion from working capital and/or borrowings under our revolving credit facility. As a result of the Convertible Notes becoming convertible, we have included the carrying value of the Convertible Notes, net of discount, in the current portion of long-term debt on our condensed consolidated balance sheet as of June 30, 2014. We will reassess the convertibility of the Convertible Notes, and the related balance sheet classification, on a quarterly basis. In the event that a holder exercises the right to convert its note, we will write-off a ratable portion of the remaining debt issuance costs and unamortized discount to interest expense. Based on a June 30, 2014 stock price of $63.15, the “if-converted” value of the Convertible Notes exceeded the principal amount by approximately $56.3 million. Through August 8, 2014, no holders of the Convertible Notes have elected to convert their notes.

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 buyers. 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, 2014, we were in compliance with all covenants related to the Convertible Notes and the 2022 Senior Notes, and expect to remain in compliance throughout the next 12-month period.

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, 2014, the borrowing base was $450 million. The borrowing base 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 affiliated partnerships. The 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 our affiliated partnerships are guarantors of our obligations under the revolving credit facility. We had no outstanding draws on our revolving credit facility as of June 30, 2014 or December 31, 2013.

As of June 30, 2014, Riley Natural Gas, a wholly-owned subsidiary of PDC, had an irrevocable standby letter of credit of approximately $11.7 million in favor of a third-party transportation service provider to secure firm transportation of the natural gas produced by third-party producers for whom we market production in the Appalachian Basin. The letter of credit expires in September 2014. The letter of credit reduces the amount of available funds under our revolving credit facility by an equal amount. As of June 30, 2014, the available funds under our revolving credit facility, including a reduction for the $11.7 million irrevocable standby letter of credit in effect, was $438.3 million.

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

As of June 30, 2014, we were in compliance with all the revolving credit facility covenants and expect to remain in compliance throughout the next 12-month period.

PDCM Credit Facility. PDCM has a credit facility dated April 2010, as amended in February 2014, with a borrowing base of $105 million, of which our proportionate share is approximately $53 million. The maximum allowable facility amount is $400 million. 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 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 is utilized by PDCM for the exploration and development of its Marcellus Shale assets. In February 2014, PDCM entered into a sixth amendment to its credit agreement. The amendment increased the amount of future production from proved developed and producing properties that is permitted to be hedged. As of June 30, 2014, our proportionate share of PDCM's outstanding credit facility balance was $47.0 million compared to $37.0 million as of December 31, 2013. The weighted-average borrowing rate on PDCM's credit facility was 3.8% per annum as of June 30, 2014, compared to 3.7% as of December 31, 2013.

The credit facility contains covenants customary for agreements of this type, with the most restrictive being certain financial tests that must be met on a quarterly basis. The financial tests, 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 4.25 to 1.0 (declining 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, 2014, PDCM was in compliance with all credit facility covenants and expects to remain in compliance throughout the next 12-month period.

PDCM Second Lien Term Loan

In July 2013, PDCM entered into a Second Lien Credit Agreement ("Term Loan Agreement") with Wells Fargo Energy Capital as administrative agent and a syndicate of other lenders party thereto. The aggregate commitment under the Term Loan 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 reserve value increases and the covenants under the Term Loan Agreement allow. The Term Loan Agreement matures in October 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. As of June 30, 2014, amounts borrowed and outstanding on the Term Loan Agreement were $30.0 million, of which our proportionate share is $15 million. The weighted-average interest rate on the term loan was 8.5% per annum as of both June 30, 2014 and December 31, 2013.

The Term Loan Agreement contains financial covenants, as defined in the agreement, that must be met on a quarterly basis, including requirements to maintain a minimum current ratio of 1.0 to 1.0, not to exceed a debt to EBITDAX ratio of 4.5 to 1.0, a minimum interest coverage ratio of 2.25 to 1.0 and a present value of future net revenues to total debt ratio of 1.50 to 1.00.

As of June 30, 2014, PDCM was in compliance with all Term Loan Agreement covenants and expects to remain in compliance throughout the next 12-month period.

NOTE 8 - ASSET RETIREMENT OBLIGATIONS

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

	Amount (in thousands)
Balance at beginning of period, January 1	$41,030
Obligations incurred with development activities	341
Accretion expense	1,716
Revisions in estimated cash flows	(134)
Obligations discharged with divestitures of properties and asset retirements	(2,884)
Balance end of period, June 30	40,069
Less: Current portion	(1,158)
Long-term portion	$38,911

NOTE 9 - COMMITMENTS AND CONTINGENCIES

Firm Transportation, Processing and Sales Agreements. We enter into contracts that provide firm transportation, sales and processing services on pipeline systems through which we transport or sell natural gas. Satisfaction of the volume requirements includes volumes produced by us, purchased from third parties and produced by PDCM and other third-party working interest owners. 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 or not the required volumes are delivered. 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 as of June 30, 2014:

	For the Twelve Months Ending June 30,						
Area	2015	2016	2017	2018	2019 and Through Expiration	Total	Expiration Date
Natural gas (MMcf)							
Appalachian Basin	19,033	19,862	20,987	20,987	114,928	195,797	January 31, 2026
Utica Shale	2,737	2,745	2,737	2,737	13,929	24,885	July 22, 2023
Total	21,770	22,607	23,724	23,724	128,857	220,682	
Dollar commitment (in thousands)	$7,356	$7,530	$7,746	$7,092	$35,075	$64,799	

On July 29, 2014, we signed a definitive agreement pursuant to which we agreed to sell our entire 50% ownership interest in PDCM to an unrelated third-party. Pursuant to the definitive agreement, approximately 137,865 MMcf and $31.1 million of our Appalachian Basin firm transportation obligation will be assumed by the buyer upon the closing of the transaction. There can be no assurance that we will be successful in closing the transaction. In addition, we may have greater than expected purchase price reductions. See Note 15, Subsequent Events, for additional information.

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.

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Class Action Regarding 2010 and 2011 Partnership Purchases

In December 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. In January 2014, the plaintiffs were certified as a class by the court. A jury trial originally scheduled for May 2014 has been rescheduled to begin in September 2014. We have held mediation meetings with plaintiffs and have proposed a settlement to resolve the alleged class action. Our proposed settlement includes a transfer of interests, primarily net profit interests which would generate cash in future years, in a certain number of future wells, plus a lesser value in an up-front cash payment. The mediation effort is ongoing; but there can be no assurance that the mediation meetings will continue or will result in a settlement on the terms we proposed or at all. During the quarter ended June 30, 2014, we recorded a litigation charge of $20.8 million, included in general and administrative expense in the condensed consolidated statements of operations, for a total accrued liability of $24.1 million at June 30, 2014, which is included in other accrued expenses in the condensed consolidated balance sheet. If the matter proceeds to trial, plaintiffs have indicated that they will seek damages of approximately $175 million, plus pre-judgment interest. We continue to believe we have good defenses to both the asserted claims and plaintiffs’ damage calculations.

Environmental. Due to the nature of the natural gas and oil industry, we are exposed to environmental risks. We have various policies and procedures designed to mitigate the risks of environmental contamination and related liabilities. 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, 2014 and December 31, 2013, we had accrued environmental liabilities in the amount of $6.2 million and $5.4 million, respectively, included in other accrued expenses on the condensed consolidated balance sheets. We are not aware of any environmental claims existing as of June 30, 2014 which have not been provided for or would otherwise be expected to 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.

In June 2014, we received an information request from the Environmental Protection Agency (the "EPA") pursuant to Sections 308 and 311 of the Clean Water Act (the "CWA") regarding a discharge of oil and related materials that occurred in May related to a mechanical failure during drilling at an Ohio location. The requested information relates to the facility from which the discharge occurred and details regarding the discharge. To date, the EPA has not issued any notice that a violation of the CWA occurred or sought to impose any fine or other relief in connection with the discharge. While the results cannot be predicted with certainty, we do not expect the ultimate resolution of this information request or any subsequent proceedings to have a material adverse effect on our financial condition or results of operation.

Employment Agreements with Executive Officers. Each of our senior executive officers, except the current Chief Executive Officer, 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. In June 2014, we announced a leadership transition and entered into a consulting agreement with our current Chief Executive Officer pursuant to which he will provide consulting services to the Company in 2015. Under the agreement, the current Chief Executive Officer ceased to be a participant in our executive severance plan.

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,	
	2014	2013	2014	2013
	(in thousands)			
Stock-based compensation expense	$5,032	$4,349	$8,879	$6,951
Income tax benefit	(1,912)	(1,661)	(3,374)	(2,655)
Net stock-based compensation expense	$3,120	$2,688	$5,505	$4,296

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.

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In January 2014, the Compensation Committee awarded 88,248 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, 2014		2013	
Expected term of award	6 years		6 years	
Risk-free interest rate	2.1	%	1.0	%
Expected volatility	65.6	%	65.5	%
Weighted-average grant date fair value per share	$29.96		$21.96	

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, 2014				2013			
	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,	190,763	$ 33.77			118,832	$ 30.80		
Awarded	88,248	49.57			87,078	37.18		
Outstanding at June 30,	279,011	38.77	8.3	6,803	205,910	33.50	8.6	3,703
Vested and expected to vest at June 30,	268,453	38.53	8.3	6,609	196,421	33.40	8.6	3,552
Exercisable at June 30,	109,920	32.71	7.3	3,346	67,069	29.99	7.6	1,441

Total compensation cost related to SARs granted, net of estimated forfeitures, and not yet recognized in our condensed consolidated statement of operations as of June 30, 2014 was $3.5 million. The cost is expected to be recognized over a weighted-average period of 2.0 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 years. The time-based shares vest ratably on each annual anniversary following the grant date if the participant is continuously employed.

In January 2014, the Compensation Committee awarded a total of 104,467 time-based restricted shares to our executive officers that vest ratably over a three-year period ending on January 16, 2017.

The following table presents the changes in non-vested time-based awards to all employees, including executive officers, for the six months ended June 30, 2014:

	Shares	Weighted-Average Grant-Date Fair Value
Non-vested at December 31, 2013	651,781	$36.36
Granted	280,835	56.56
Vested	(202,587)	36.73
Forfeited	(18,385)	38.56
Non-vested at June 30, 2014	711,644	44.18

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	As of/Year Ended June 30,	
	2014	2013
	(in thousands, except per share data)	
Total intrinsic value of time-based awards vested	$11,690	$8,544
Total intrinsic value of time-based awards non-vested	44,940	37,082
Market price per common share as of June 30,	63.15	51.48
Weighted-average grant date fair value per share	56.56	44.24

Total compensation cost related to non-vested time-based awards, net of estimated forfeitures, and not yet recognized in our condensed consolidated statements of operations as of June 30, 2014 was $24.0 million. This cost is expected to be recognized over a weighted-average period of 2.2 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 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 2014, the Compensation Committee awarded a total of 42,151 market-based restricted shares to our executive officers. In addition to continuous employment, the vesting of these shares is contingent on the Company's total shareholder return ("TSR"), which is essentially the Company’s stock price change including any dividends, as compared to the TSR of a set group of 15 peer companies. The shares are measured over a three-year period ending on December 31, 2016 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,			
	2014		2013	
Expected term of award	3 years		3 years	
Risk-free interest rate	0.8	%	0.4	%
Expected volatility	55.2	%	56.6	%
Weighted-average grant date fair value per share	$56.87		$49.04	

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.

The following table presents the change in non-vested market-based awards during six months ended June 30, 2014:

	Shares	Weighted-Average Grant-Date Fair Value per Share
Non-vested at December 31, 2013	72,111	$43.75
Granted	42,151	56.87

Non-vested at June 30, 2014	114,262	48.59

	As of/Year Ended June 30,	
	2014	2013
	(in thousands, except per share data)	
Total intrinsic value of market-based awards non-vested	$7,216	$4,235
Market price per common share as of June 30,	63.15	51.48
Weighted-average grant date fair value per share	56.87	49.04

Total compensation cost related to non-vested market-based awards, net of estimated forfeitures, and not yet recognized in our condensed consolidated statement of operations as of June 30, 2014 was $3.1 million. This cost is expected to be recognized over a weighted-average period of 2.0 years.

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 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,	
	2014	2013	2014	2013
	(in thousands)			
Weighted-average common shares outstanding - basic	35,762	30,332	35,726	30,301
Dilutive effect of:				
Restricted stock	—	313	—	—
SARs	—	26	—	—
Stock options	—	1	—	—
Non-employee director deferred compensation	—	4	—	—
Convertible notes	—	338	—	—
Weighted-average common shares and equivalents outstanding - diluted	35,762	31,014	35,726	30,301

We reported a net loss for the three and six months ended June 30, 2014 and for the six months ended June 30, 2013. As a result, our basic and diluted weighted-average common shares outstanding were the same due to the fact that the effect of the common share equivalents was anti-dilutive.

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,	
	2014	2013	2014	2013
	(in thousands)			
Weighted-average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:				
Restricted stock	896	5	859	893
SARs	92	20	96	54

Stock options	4	—	4	7
Non-employee director deferred compensation	5	—	5	4
Convertible notes	881	—	758	206
Total anti-dilutive common share equivalents	1,878	25	1,722	1,164

In November 2010, we issued our Convertible Notes, which give the holders the right to convert the aggregate principal amount into 2.7 million shares of our common stock at a conversion price of $42.40 per share. The Convertible 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 upon conversion of the Convertible Notes were excluded from the diluted earnings per share calculation for the three and six months ended June 30, 2014 and the six months ended June 30, 2013 as the effect would be anti-dilutive to our earnings per share. Shares issuable upon conversion of the Convertible 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.

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

Appalachian Basin. In December 2013, we divested our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin crude oil and natural gas properties previously owned directly by us, as well as through our proportionate share of PDCM, for aggregate consideration of approximately $20.6 million, of which our share of the proceeds was approximately $5.1 million. We received our proportionate share of cash proceeds of $0.9 million and recorded our proportionate share of a note receivable and account receivable from the buyer of $3.3 million and $0.8 million, respectively. Concurrent with the closing of the transaction, our $6.7 million irrevocable standby letter of credit and an agreement for firm transportation services was released and novated to the buyer. We, through our ownership in PDCM, retained all zones, formations and intervals below the Upper Devonian formation including the Marcellus Shale, Utica Shale and Huron Shale. The divestiture of these assets did not meet the requirements to be accounted for as discontinued operations. On July 29, 2014, we signed a definitive agreement to sell our entire 50% interest in PDCM to an unrelated third-party. See Note 15, Subsequent Events, for additional information.There can be no assurance we will be successful in closing the transaction. In addition, we may have greater than expected purchase price reductions.

Piceance Basin and NECO. In June 2013, we divested our Piceance Basin, NECO and certain other non-core Colorado oil and gas properties, leasehold mineral interests and related assets for total consideration of approximately $177.6 million, with an additional $17.0 million paid to our non-affiliated investor partners in our affiliated partnerships. The sale resulted in a pre-tax loss of $2.3 million. Additionally, certain firm transportation obligations and natural gas hedging positions were assumed by the buyer. Following the sale, 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 the three months ended June 30, 2013. The sale of our other non-core Colorado oil and gas properties did not meet the requirements to be accounted for as discontinued operations.

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

Condensed consolidated statements of operations - discontinued operations	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013
Revenues		
Crude oil, natural gas and NGLs sales	$10,182	$20,456
Sales from natural gas marketing	586	1,036
Well operations, pipeline income and other	409	859
Total revenues	11,177	22,351
Costs, expenses and other		
Production costs	2,564	7,957
Cost of natural gas marketing	540	994
Depreciation, depletion and amortization	—	2,258
Other	1,959	2,454
Loss on sale of properties and equipment	1,076	1,076
Total costs, expenses and other	6,139	14,739
Income from discontinued operations	5,038	7,612
Provision for income taxes	(1,622)	(2,659)
Income from discontinued operations, net of tax	$3,416	$4,953

NOTE 13 - TRANSACTIONS WITH AFFILIATES

PDCM and Affiliated Partnerships. Our Gas Marketing segment markets the natural gas produced by PDCM and our affiliated partnerships in the Appalachian Basin. Our cost of natural gas marketing includes $10.7 million and $20.1 million for the three and six months ended June 30, 2014, respectively, related to the marketing of natural gas on behalf of PDCM compared to $4.1 million and $7.8 million for the three and six months ended June 30, 2013, respectively. Our cost of natural gas marketing includes $0.3 million and $0.6 million for the three and six months ended June 30, 2013, respectively, related to the marketing of natural gas on behalf of our affiliated partnerships.

Amounts due from/to affiliates primarily relate to amounts billed for certain well operating and administrative services provided to PDCM and, to a lesser extent, costs resulting from audit and tax preparation services for our affiliated partnerships. Amounts billed to PDCM for these services were $2.1 million and $4.4 million in the three and six months ended June 30, 2014, respectively, compared to $3.4 million and $6.8 million in the three and six months ended June 30, 2013, respectively. 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:

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

Condensed consolidated statement of operations line item	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
	(in thousands)			
Production costs	$417	$986	$1,022	$2,053
Exploration expense	—	134	—	239
General and administrative expense	625	618	1,181	1,132

NOTE 14 - BUSINESS SEGMENTS

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

Oil and Gas Exploration and Production. Our Oil and Gas Exploration and Production segment includes all of our 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 unallocated other revenue, less corporate general administrative expense, corporate DD&A expense, interest income and interest expense. Unallocated assets include assets utilized for corporate, general and administrative purposes, as well as assets not specifically included in our two business segments.

The following tables present our segment information:

	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
	(in thousands)			
Segment revenues:				
Oil and gas exploration and production	$87,057	$103,226	$190,382	$161,382
Gas marketing	22,415	18,079	49,352	31,749
Total revenues	$109,472	$121,305	$239,734	$193,131
Segment income (loss) before income taxes:				
Oil and gas exploration and production	$6,265	$56,372	$40,271	$22,671
Gas marketing	(13)	13	54	(52)
Unallocated	(54,985)	(30,092)	(92,572)	(59,773)
Income (loss) before income taxes	$(48,733)	$26,293	$(52,247)	$(37,154)

	June 30, 2014	December 31, 2013
	(in thousands)	
Segment assets:		
Oil and gas exploration and production	$1,977,181	$1,937,251
Gas marketing	23,669	20,342
Unallocated	85,575	67,610
Total assets	$2,086,425	$2,025,203

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NOTE 15 - SUBSEQUENT EVENTS

On July 29, 2014, we signed a definitive agreement pursuant to which we agreed to sell our entire 50% ownership interest in PDCM to an unrelated third-party for aggregate consideration of approximately $250 million, subject to certain purchase price adjustments. Our net pre-tax proceeds from the sale, after our share of PDCM's debt repayment and other working capital adjustments, is expected to be approximately $190 million, comprised of $150 million in cash and a $40 million promissory note due in 2020. The transaction includes the buyer's assumption of our share of the firm transportation obligations related to the assets owned by PDCM as well as our share of certain of PDCM's natural gas hedging positions for the years 2014 and 2015. The divestiture is expected to close in October 2014. There can be no assurance we will be successful in closing the transaction. In addition, we may have greater than expected purchase price reductions.

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 substantial increases in crude oil, natural gas and NGLs sales from continuing operations during the three and six months ended June 30, 2014 as a result of our significant increase in production and, to a lesser extent, higher commodity prices. Total crude oil, natural gas and NGLs sales increased $62.4 million, or 81%, and $112.8 million, or 72%, during the three and six months ended June 30, 2014, respectively, compared to the three and six months ended June 30, 2013. Our crude oil, natural gas and NGLs production from continuing operations averaged 29.7 Mboe per day and 28.2 Mboe per day during the three and six months ended June 30, 2014, respectively, an increase of approximately 64% and 54% compared to the three and six months ended June 30, 2013, respectively. The increase in production is primarily attributable to our successful horizontal Niobrara and Codell drilling program in the Wattenberg Field. Our liquids percentage of total production from continuing operations was 55% and 57% during the three and six months ended June 30, 2014, respectively, compared to 54% during each of the same prior year periods. Higher crude oil and natural gas index prices at derivatives settlement resulted in negative net settlements on derivatives of $10.4 million and $18.7 million during the three and six months ended June 30, 2014, respectively, compared to positive net settlements on derivatives of $3.9 million and $12.4 million during the three and six months ended June 30, 2013, respectively. Crude oil, natural gas and NGLs sales including the impact of net settlements on derivatives was $129.5 million and $251.1 million during the three and six months ended June 30, 2014, respectively, compared to $81.4 million and $169.4 million during the three and six months ended June 30, 2013, respectively. This represents increases of 59% and 48% during the three and six months ended June 30, 2014, respectively, compared to the same prior year periods.

Three other areas showed significant changes during 2014 as compared to 2013. General and administrative expense increased to $40.7 million and $64.3 million during the three and six months ended June 30, 2014, respectively, compared to $15.8 million and $30.9 million during the three and six months ended June 30, 2013, respectively, primarily attributable to a $20.8 million and $24.1 million charge recorded during the respective periods in connection with certain class action litigation. In addition, the crude oil and natural gas forward curves shifted higher during the current year resulting in a negative net change in the fair value of unsettled derivatives of $43 million and $61.9 million during the three and six months ended June 30, 2014, respectively, compared to a positive net change in the fair value of unsettled derivatives of $20.8 million during the three months ended June 30, 2013 and a negative net change in the fair value of unsettled derivatives of $10 million during the six months ended June 30, 2013. Finally, depreciation, depletion and amortization expense increased to $53.7 million and $100.4 million during the three and six months ended June 30, 2014, respectively, compared to $27.8 million and $55.7 million during the three and six months ended June 30, 2013, respectively, due primarily to the increase in production.

Select financial metrics for the three months ended June 30, 2014 compared to the three months ended June 30, 2013 were as follows:

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- Adjusted net loss of $1.5 million compared to an adjusted net income of $7.0 million in the prior period. Excluding the after-tax impact of the litigation charge recorded in general and administrative expense, adjusted net income in the current period would have been $11.4 million;
- Adjusted cash flows from operations of $55.0 million compared to $46.4 million in the prior period. Excluding the after-tax impact of the litigation charge recorded in general and administrative expense, adjusted cash flows from operations in the current period would have been $75.8 million; and
- Adjusted EBITDA of $62.7 million compared to $54.1 million in the prior period. Excluding the impact of the litigation charge recorded in general and administrative expense, adjusted EBITDA in the current period would have been $83.5 million.

Select financial metrics for the six months ended June 30, 2014 compared to the six months ended June 30, 2013 were as follows:

- Adjusted net income of $8.1 million compared to an adjusted net loss of $13.4 million in the prior period. Excluding the after-tax impact of the litigation charge recorded in general and administrative expense during the six months ended June 30, 2014 and the impairment charge recorded during the six months ended June 30, 2013 related to our shallow Upper Devonian Appalachian Basin assets, adjusted net income in the current period would have been $23.0 million compared to $14.4 million during the prior period;
- Adjusted cash flows from operations of $124.7 million compared to $98.7 million in the prior period. Excluding the after-tax impact of the litigation charge recorded in general and administrative expense, adjusted cash flows from operations in the current period would have been $148.8 million; and
- Adjusted EBITDA of $139.2 million compared to $115.3 million in the prior period. Excluding the impact of the litigation charge recorded in general and administrative expense, adjusted EBITDA in the current period would have been $163.3 million.

Adjusted net income/loss, adjusted cash flows from operations and adjusted EBITDA are non-U.S. GAAP financial measures. See Non-U.S. GAAP Financial Measures and Reconciliation of Non-U.S. GAAP Financial Measures, below, for a more detailed discussion of these non-U.S. GAAP financial measures.

Available liquidity as of June 30, 2014 was $484.2 million, including $6.0 million related to PDCM, compared to $647.0 million, including $16.1 million related to PDCM, as of December 31, 2013. Available liquidity is comprised of $40.4 million of cash and cash equivalents and $443.8 million available for borrowing under our revolving credit facilities as of June 30, 2014. We believe we have sufficient liquidity to allow us to execute our expanded drilling program through 2014.

In July 2014, we signed a definitive agreement pursuant to which we agreed to sell our entire 50% ownership interest in PDCM to an unrelated third-party for aggregate consideration of approximately $250 million, subject to certain purchase price adjustments. Our net pre-tax proceeds from the sale, after our share of PDCM's debt repayment and other working capital adjustments, is expected to be approximately $190 million, comprised of $150 million in cash and a $40 million promissory note due in 2020. The transaction includes the buyer's assumption of our share of the firm transportation obligations related to the assets owned by PDCM as well as our share of certain PDCM's natural gas hedging positions for the years 2014 and 2015. The divestiture is expected to close in October 2014. We expect to use the proceeds from the divestiture to fund a portion of our 2014 capital program. There can be no assurance that this transaction will close as planned. In addition, we may have greater than expected purchase price reductions.

Operational Overview

Drilling Activities. During the six months ended June 30, 2014, we continued to execute our strategic plan of increasing our overall production and liquids mix by focusing our drilling operations primarily in the liquid-rich Wattenberg Field in Colorado and the emerging Utica Shale play in southeastern Ohio.

In the Wattenberg Field, we are currently running five drilling rigs. We spudded 55 horizontal wells and turned in line 40 horizontal wells during the six months ended June 30, 2014. We also participated in 42 gross, 9.5 net, horizontal non-operated drilling projects and turned in line 22 gross, 4.7 net, horizontal non-operated wells. In the Utica Shale, we had one drilling rig running during the six months ended June 30, 2014 and added a second rig in early July 2014. We spudded five horizontal wells during the six months ended June 30, 2014 and turned in line two horizontal wells. During the second quarter, a mechanical failure occurred during the drilling of a Utica Shale horizontal well leading to a loss of well control and the plugging and abandonment of the well. Costs incurred to remediate environmental issues that occurred as a result of the mechanical failure of approximately $6 million are expected to be recouped from our insurance carrier. In the Marcellus Shale, PDCM finalized drilling and completion operations on four horizontal wells that were in-process at December 31, 2013. These wells were turned in line as of June 30, 2014.

2014 Operational Outlook

We have raised our expectations with respect to 2014 production from between 9.5 MMBoe to 10 MMBoe to between 10.7 MMBoe and 10.9 MMBoe, excluding the effect of the planned PDCM divestiture. Assuming the planned divestiture of PDCM closes in mid-October 2014, we would expect the new 2014 production range to decrease by approximately 0.3 MMBoe. Overall, our previously announced 2014 capital budget is unchanged at $647 million and is expected to be used primarily for development drilling and selective acquisitions of additional acreage. However, the budget now includes $555 million of development capital and $92 million for leasehold acquisitions, exploration and other expenditures. The approximately $20 million reduction in developmental capital is due to several non-operated projects in the Wattenberg Field now being projected for 2015, rather than the fourth quarter of 2014. The increase in the budget for leasehold acquisitions is due to several additional opportunities we have pursued to purchase Utica acreage. We may again 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.

Wattenberg Field. We expect to invest approximately $443 million in the Wattenberg Field in 2014, where we are currently running a five-rig drilling program. We expect to spud 123 gross operated horizontal wells in the field, of which 96 are expected to be turned in line during 2014. Approximately $76 million of the total Wattenberg Field capital budget is expected to be allocated to non-operated projects. During the six months ended June 30, 2014, we invested approximately $207.1 million, or 47%, of our 2014 capital budget for the Wattenberg Field.

Utica Shale. We expect to invest approximately $192 million in the Utica Shale in 2014 to spud 18 horizontal wells, of which eight are expected to be turned in line during 2014. A second drilling rig was deployed in early July 2014. The Utica capital budget includes approximately $59 million to acquire additional contiguous acreage. During the six months ended June 30, 2014, we invested approximately $65 million, or 34%, of our 2014 capital budget for the Utica Shale.

Marcellus Shale. As of June 30, 2014, PDCM had invested its full 2014 capital budget of approximately $10 million in the Marcellus Shale. PDCM's capital budget was funded by PDCM's operating activities and borrowing under its credit facility.

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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, in some cases, 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 liquidity measures or indicators 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 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,		
	2014	2013	Percentage Change	2014	2013	Percentage Change
	(dollars in millions, except per unit data)					
Production (1)						
Crude oil (MBbls)	1,077.1	617.7	74.4 %	2,120.0	1,286.0	64.9 %
Natural gas (MMcf)	7,283.2	4,511.5	61.4 %	13,161.5	9,061.3	45.2 %
NGLs (MBbls)	411.0	276.5	48.6 %	790.5	514.8	53.6 %
Crude oil equivalent (MBoe) (2)	2,702.1	1,646.1	64.2 %	5,104.2	3,311.1	54.2 %
Average MBoe per day	29.7	18.1	64.1 %	28.2	18.3	54.1 %
Crude Oil, Natural Gas and NGLs Sales						
Crude oil	$98.9	$53.9	83.5 %	$188.6	$112.1	68.2 %
Natural gas	29.7	17.1	73.7 %	56.5	31.1	81.7 %
NGLs	11.3	6.5	73.8 %	24.7	13.8	79.0 %
Total crude oil, natural gas and NGLs sales	$139.9	$77.5	80.5 %	$269.8	$157.0	71.8 %
Net Settlements on Derivatives (3)						
Natural gas	$(1.9)	$3.1	*	$(5.9)	$11.2	*
Crude oil	(8.5)	0.8	*	(12.8)	1.2	*
Total net settlements on derivatives	$(10.4)	$3.9	*	$(18.7)	$12.4	*
Average Sales Price (excluding net settlements on derivatives)						
Crude oil (per Bbl)	$91.77	$87.32	5.1 %	$88.94	$87.13	2.1 %
Natural gas (per Mcf)	4.08	3.79	7.7 %	4.29	3.44	24.7 %
NGLs (per Bbl)	27.60	23.55	17.2 %	31.24	26.76	16.7 %
Crude oil equivalent (per Boe)	51.78	47.10	9.9 %	52.85	47.41	11.5 %
Average Lifting Cost (per Boe) (4)						
Wattenberg Field	$5.12	$4.01	27.7 %	$4.64	$3.90	19.0 %
Utica Shale	1.85	3.21	(42.4)%	1.30	3.00	(56.7)%
Marcellus Shale	0.96	5.19	(81.5)%	1.14	5.20	(78.1)%
Weighted-average	4.28	4.19	2.1 %	3.87	4.09	(5.4)%
Natural Gas Marketing Contribution Margin (5)	$—	$—	*	$0.1	$—	*
Other Costs and Expenses						
Exploration expense	$0.3	$1.4	(80.7)%	$0.6	$3.1	(81.3)%
Impairment of crude oil and natural gas properties	0.9	1.5	(37.5)%	1.9	48.0	*
General and administrative expense	40.7	15.8	157.7 %	64.3	30.9	108.0 %
Depreciation, depletion and amortization	53.7	27.8	93.3 %	100.4	55.7	80.1 %

Interest Expense	$13.1	$13.1	(0.2)%	$25.9	$26.4	(2.1)%

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

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(1) Production is net and determined by multiplying the gross production volume of properties in which we have an interest by our ownership percentage.
(2) One Bbl of crude oil or NGL equals six Mcf of natural gas.
(3) Represents net settlements on derivatives related to crude oil and natural gas sales, which do not include net settlements on derivatives 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 net settlements and net change in fair value of unsettled derivatives related to natural gas marketing activities.

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, 2014	2013	Percentage Change	Six Months Ended June 30, 2014	2013	Percentage Change
Crude oil (MBbls)						
Wattenberg Field	1,008.5	605.5	66.6 %	1,961.1	1,256.2	56.1 %
Utica Shale	68.6	11.3	*	158.9	28.0	*
Marcellus Shale (1)	—	0.9	*	—	1.8	*
Total	1,077.1	617.7	74.4 %	2,120.0	1,286.0	64.9 %
Natural gas (MMcf)						
Wattenberg Field	4,338.2	2,916.2	48.8 %	7,653.2	5,891.7	29.9 %
Utica Shale	582.3	43.6	*	1,011.6	43.9	*
Marcellus Shale (1)	2,362.7	1,551.7	52.3 %	4,496.7	3,125.7	43.9 %
Total	7,283.2	4,511.5	61.4 %	13,161.5	9,061.3	45.2 %
NGLs (MBbls)						
Wattenberg Field	386.3	275.2	40.4 %	730.2	513.5	42.2 %
Utica Shale	24.7	1.3	*	60.3	1.3	*
Total	411.0	276.5	48.6 %	790.5	514.8	53.6 %
Crude oil equivalent (MBoe)						
Wattenberg Field	2,117.9	1,366.7	55.0 %	3,966.8	2,751.7	44.2 %
Utica Shale	190.4	19.8	*	387.9	36.6	*
Marcellus Shale (1)	393.8	259.6	51.7 %	749.5	522.8	43.4 %
Total	2,702.1	1,646.1	64.2 %	5,104.2	3,311.1	54.2 %

*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 net settlements on derivatives)	Three Months Ended June 30, 2014	2013	Percentage Change	Six Months Ended June 30, 2014	2013	Percentage Change
Crude oil (per Bbl)						
Wattenberg Field	$91.56	$87.31	4.9%	$88.88	$87.09	2.1%
Utica Shale	94.79	87.72	8.1%	89.75	89.01	0.8%
Marcellus Shale (1)	—	88.05	*	—	87.93	*
Weighted-average price	91.77	87.32	5.1%	88.94	87.13	2.1%
Natural gas (per Mcf)						
Wattenberg Field	$4.26	$3.71	14.8%	$4.35	$3.36	29.5%
Utica Shale	4.01	3.53	13.6%	4.27	3.52	21.3%
Marcellus Shale (1)	3.77	3.94	(4.3)%	4.20	3.58	17.3%
Weighted-average price	4.08	3.79	7.7%	4.29	3.44	24.7%
NGLs (per Bbl)						
Wattenberg Field	$26.67	$23.46	13.7%	$29.48	$26.72	10.3%
Utica Shale	42.15	41.21	2.3%	52.59	41.21	27.6%
Weighted-average price	27.60	23.55	17.2%	31.24	26.76	16.7%
Crude oil equivalent (per Boe)						

Wattenberg Field	$57.19	$51.32	11.4%	$57.76	$51.94	11.2%
Utica Shale	51.91	60.27	(13.9)%	56.10	73.72	(23.9)%
Marcellus Shale (1)	22.62	23.89	(5.3)%	25.19	21.72	16.0%
Weighted-average price	51.78	47.10	9.9%	52.85	47.41	11.5%

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

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(1) On July 29, 2014, we signed a definitive agreement to sell our entire 50% interest in PDCM to an unrelated third-party. See Note 15, Subsequent Events, to our condensed consolidated financial statements included elsewhere in this report for additional information. There can be no assurance we will be successful in closing the transaction. In addition, we may have greater than expected purchase price reductions.

For the three and six months ended June 30, 2014, crude oil, natural gas and NGLs sales revenue increased compared to the three and six months ended June 30, 2013 due to the following (in millions):

	June 30, 2014	
	Three Months Ended	Six Months Ended
Increase in production	$53.8	$94.1
Increase in average natural gas price	2.1	11.3
Increase in average crude oil price	4.8	3.8
Increase in average NGLs price	1.7	3.6
Total increase in crude oil, natural gas and NGLs sales revenue	$62.4	$112.8

As expected, we have experienced increases in gathering system pressures in the Wattenberg Field by our primary third-party mid-stream provider during the first half of 2014 and we have factored these higher line pressures into our production estimates for 2014. Overall, the line pressures in the first half of 2014 were within our expectations and were lower than they were in the comparable periods of 2012 and 2013, primarily due to the commissioning of the O'Connor gas plant in the fall of 2013, the recent startup of an additional compressor station in 2014 and relatively mild summer temperatures in 2014. Ongoing industry drilling activity in the area will continue to increase volumes on the gathering system and our midstream service provider will be challenged to keep pace with new midstream infrastructure. We and other operators in the field are working with the midstream service provider, who continues to implement a multi-year facility expansion program that will significantly increase the long-term gathering and processing capacity of the system. 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 additional facilities going forward is beyond our control.

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.

Crude oil pricing is predominately driven by the physical market, supply and demand, financial markets and national and international politics. In the Wattenberg Field, crude oil is sold under various purchase contracts with monthly pricing provisions based on NYMEX pricing, adjusted for differentials. We are currently pursuing various alternatives with respect to oil transportation, particularly in the Wattenberg Field, with a view toward improving pricing and takeaway capacity. In the Utica Shale, crude oil and condensate is sold to local purchasers at each individual well site based on NYMEX pricing, adjusted for differentials. 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 the Wattenberg Field is based on CIG prices, adjusted for certain deductions, while natural gas produced in the Utica Shale and Marcellus Shale is based on NYMEX pricing, adjusted for differentials and other deductions. The differentials at our two primary sales hubs for these basins have recently widened primarily due to current oversupply in the Appalachian region. We anticipate that these widened differentials will continue through 2014. Our price for NGLs produced in the Wattenberg Field is based on a combination of prices from both the Conway hub in Kansas and Mt. Belvieu in Texas where this production is marketed. The NGLs produced in the Utica Shale are sold based on month-to-month pricing in various markets.

We currently use the "net-back" method of accounting for crude oil, natural gas and NGLs production from the Wattenberg Field and crude oil from the Utica Shale as the majority of the purchasers of these commodities also provide transportation, gathering and processing services. We sell our commodities at the wellhead and collect a price and recognize revenues based on the wellhead sales price as transportation and processing 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. Natural gas and NGLs sales related to production from the Utica Shale and Marcellus Shale are recognized based on gross prices as the purchasers do not provide transportation, gathering and processing services and we recognize expenses relating to those services as production costs.

Production Costs

Production costs include lease operating expenses, production taxes, transportation, gathering and processing costs 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,	
	2014	2013	2014	2013
	(in millions)			
Lease operating expenses	$11.6	$6.9	$19.8	$13.5
Production taxes	8.7	5.3	16.3	10.7
Transportation, gathering and processing expenses	2.2	2.7	4.4	4.3
Overhead and other production expenses	4.3	1.3	7.5	3.5
Total production costs	$26.8	$16.2	$48.0	$32.0
Total production costs per Boe	$9.90	$9.83	$9.40	$9.67

Lease operating expenses. The $4.7 million increase in lease operating expenses during the three months ended June 30, 2014 compared to the three months ended June 30, 2013 was primarily due to an increase of $2.1 million for workover and maintenance related projects, an increase of $0.7 million for additional wages and employee benefits, $0.7 million for environmental compliance and remediation projects and $0.3 million for the rental of additional compressors used to accommodate high line pressures in the Wattenberg Field. The $6.3 million increase in lease operating expenses during the six months ended June 30, 2014 compared to the six months ended June 30, 2013 was primarily due to an increase of $2.4 million for workover and maintenance related projects, an increase of $1.0 million in additional wages and employee benefits, $0.9 million for environmental compliance and remediation projects, $0.7 million for the rental of additional compressors used to accommodate high line pressures in the Wattenberg Field and $0.5 million for expenses incurred on the increasing number of non-operated wells.

Production taxes. Production taxes are directly related to crude oil, natural gas and NGLs sales. The $3.4 million, or 64%, increase in production taxes for the three months ended June 30, 2014 compared to the three months ended June 30, 2013, was primarily related to the 81% increase in crude oil, natural gas and NGLs sales. Similarly, the $5.6 million, or 52%, increase in production taxes for the six months ended June 30, 2014 compared to the six months ended June 30, 2013, was primarily related to the 72% increase in crude oil, natural gas and NGLs sales.

Transportation, gathering and processing expenses. The $0.5 million, or 19%, decrease in transportation, gathering and processing expenses for the three months ended June 30, 2014 compared to the three months ended June 30, 2013 was primarily attributable to a reduction in our unutilized takeaway capacity costs resulting from the divestiture of our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin producing properties. The $0.1 million, or 2%, increase in transportation, gathering and processing expenses for the six months ended June 30, 2014 compared to the six months ended June 30, 2013 was primarily attributable to an increase in Utica gas transportation expenses offset in part by a a reduction in our unutilized takeaway capacity costs resulting from the divestiture of our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin producing properties.

Overhead and other production expenses. Overhead and other production expenses increased $3.0 million during the three months ended June 30, 2014 as compared to the three months ended June 30, 2013. The increase consisted of a $1.5 million increase in wages and employee benefits, mostly attributable to the fact that Utica Shale employee costs moved to production expense from exploration expense and an increase of $1.0 million for the write-off of costs due to changes in our drilling locations. Overhead and other production expenses increased $4.0 million during the six months ended June 30, 2014 as compared to the six months ended June 30, 2013. The increase consisted of a $2.9 million increase in wages and employee benefits, mostly attributable to the fact that Utica Shale employee costs moved to production expense from exploration expense and an increase of $0.9 million for the write-off of costs due to changes in our drilling locations.

Commodity Price Risk Management, Net

Commodity price risk management, net, includes cash settlements upon maturity of our derivative instruments and the change in fair value of unsettled derivatives 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 net settlements and net change in fair value of unsettled derivatives included in commodity price risk management, net:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Commodity price risk management gain (loss), net:				
Net settlements	$(10.4)	$3.9	$(18.7)	$12.4
Net change in fair value of unsettled derivatives	(43.0)	20.8	(61.9)	(10.0)
Total commodity price risk management gain (loss), net	$(53.4)	$24.7	$(80.6)	$2.4

Net settlements for the three and six months ended June 30, 2014 were primarily the result of higher crude oil and natural gas index prices at maturity of our derivative instruments compared to the respective strike prices. For the three and six months ended June 30, 2014, negative settlements on our crude oil positions were $8.5 million and $12.8 million, respectively, and negative settlements for the three and six months ended June 30, 2014 on natural gas positions, exclusive of basis swaps, were $2.2 million and $6 million, respectively. The negative settlements were slightly offset by positive settlements on our basis swap positions of $0.3 million and $0.1 million for the three and six months ended June 30, 2014, respectively. The net change in fair value of unsettled derivatives for the three and six months ended June 30, 2014 includes a $7.9 million and $8.5 million net asset increase, respectively, in the beginning-of-period fair value of derivative instruments that settled during the period. The corresponding impact of settlement of these instruments is included in net settlements for the period as discussed above. The net change in fair value of unsettled derivatives for the three and six months ended June 30, 2014 also includes a $50.9 million and $70.4 million decrease, respectively, in the fair value of unsettled derivatives during the period, primarily related to the upward shift in the crude oil forward curve.

Net settlements for the three and six months ended June 30, 2013 were mainly the result of lower natural gas and crude oil index prices at maturity of our derivative instruments compared to the respective strike prices. Positive settlements for the three and six months ended June 30, 2013 on our natural gas derivatives were $6.4 million and $18.6 million, respectively, and positive settlements were $0.8 million and $1.2 million, respectively, on our crude oil derivatives. The positive settlements on natural gas and crude oil derivatives were offset in part by negative settlements of $3.3 million and $7.4 million, respectively, on our basis swap positions. The net change in fair value of unsettled derivatives for the three and six months ended June 30, 2013 includes a $3.2 million and $9.1 million net asset reduction, respectively, in the beginning-of-period fair value of derivative instruments that settled during the period and a $24 million and $7.8 million decrease, respectively, in the fair value of unsettled derivatives during the period, primarily related to the upward shift in the crude oil and natural gas forward curves.

We use various derivative instruments to manage fluctuations in crude oil and natural gas prices. We have in place a variety of 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 strike price, adjusted for differentials.

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Natural Gas Marketing

Fluctuations in our natural gas marketing's income contribution are primarily due to fluctuations in commodity prices, cash settlements upon maturity of derivative instruments and the change in fair value of unsettled derivatives, 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,	
	2014	2013	2014	2013
	(in millions)			
Natural gas sales revenue	$22.2	$16.7	$50.0	$31.1
Net settlements from derivatives	(0.1)	(0.2)	(0.6)	—
Net change in fair value of unsettled derivatives	0.3	1.6	—	0.6
Other	—	—	—	0.1
Total sales from natural gas marketing	22.4	18.1	49.4	31.8
Costs of natural gas purchases	21.8	16.4	49.2	30.0
Net settlements from derivatives	(0.1)	(0.2)	(0.7)	(0.1)
Net change in fair value of unsettled derivatives	0.3	1.6	—	0.6
Other	0.4	0.3	0.8	1.3
Total costs of natural gas marketing	22.4	18.1	49.3	31.8
Natural gas marketing contribution margin	$—	$—	$0.1	$—

Natural gas sales revenue and cost of natural gas purchases increased in the three and six months ended June 30, 2014 compared to the three and six months ended June 30, 2013, mainly attributable to higher natural gas prices and production volumes.

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.

Exploration Expense

The following table presents the major components of exploration expense:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(in millions)			
Geological and geophysical costs	$—	$—	$—	$0.5
Operating, personnel and other	0.3	1.4	0.6	2.6
Total exploration expense	$0.3	$1.4	$0.6	$3.1

Geological and geophysical costs. Geological and geophysical costs during the six months ended June 30, 2013 were primarily related to costs associated with 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 $1.1 million and $2.0 million decrease during the three and six months ended June 30, 2014 compared to the same prior year period was primarily related to a reduction in Utica Shale personnel costs resulting from the reassignment of former exploration department personnel to other departments.

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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,	
	2014	2013	2014	2013
	(in millions)			
Impairment of proved properties	$—	$—	$—	$45.0
Impairment of individually significant unproved properties	—	0.7	—	0.8
Amortization of individually insignificant unproved properties	0.9	0.8	1.9	2.1
Total impairment of crude oil and natural gas properties	$0.9	$1.5	$1.9	$48.0

Impairment of proved properties. In the first quarter of 2013, we recognized an impairment charge of approximately $45.0 million related to all of our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin producing properties located in West Virginia and Pennsylvania previously 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. 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 these properties, including the closing of the sale of these properties.

General and Administrative Expense

General and administrative expense increased $24.9 million to $40.7 million for the three months ended June 30, 2014 compared to $15.8 million for the three months ended June 30, 2013. The increase was attributable to a $20.8 million charge recorded during the three months ended June 30, 2014 in connection with certain class action litigation (not including a $3.3 million charge recognized in the first quarter of 2014), a $2.2 million increase in payroll and employee benefits, of which $0.5 million was related to stock-based compensation, and a $1.4 million increase in costs for legal and other professional services.

General and administrative expense increased $33.4 million to $64.3 million for the six months ended June 30, 2014 compared to $30.9 million for the six months ended June 30, 2013. The increase was attributable to a $24.1 million charge recorded during the six months ended June 30, 2014 in connection with certain class action litigation, a $5 million increase in payroll and employee benefits, of which $1.6 million was related to stock-based compensation, and a $2.4 million increase in costs for legal and other professional services.

Depreciation, Depletion and Amortization Expense

Crude oil and natural gas properties. 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 $52.3 million and $97.6 million for the three and six months ended June 30, 2014, respectively, compared to $26.6 million and $53.3 million for the three and six months ended June 30, 2013. The increase in our production for the three and six months ended June 30, 2014 contributed $17 million and $28.9 million to these increases, respectively, while higher weighted-average depreciation, depletion and amortization rates contributed $8.7 million and $15.4 million for the three and six months ended June 30, 2014, respectively.

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

Operating Region/Area	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(per Boe)			
Wattenberg Field	$20.55	$17.91	$19.91	$17.45
Utica Shale	26.54	—	29.61	—
Marcellus Shale	9.51	8.07	9.51	10.13
Total weighted-average	19.37	16.14	19.12	16.10

Non-crude oil and natural gas properties. Depreciation expense for non-crude oil and natural gas properties was $1.4 million and $2.8 million for the three and six months ended June 30, 2014, respectively, compared to $1.2 million and $2.4 million for the three and six months ended June 30, 2013, respectively.

Interest Expense

Interest expense decreased $0.6 million to $25.9 million for the six months ended June 30, 2014 compared to $26.4 million for the six months ended June 30, 2013. The year-over-year decrease is primarily comprised of a $0.7 million decrease attributable to an increase in the interest expense capitalized during the six months ended June 30, 2014.

Provision for Income Taxes

See Note 6, Income Taxes, to the accompanying condensed consolidated financial statements included elsewhere in this report for a discussion of the changes in our effective tax rate for the three and six months ended June 30, 2014 compared to the three and six months ended June 30, 2013. The effective tax rate of 42.2% and 42.0% benefit on loss for the three and six months ended June 30, 2014, respectively, are based on forecasted pre-tax income for the year adjusted for permanent differences. The forecasted effective tax rate has been applied to the quarter-to-date and year-to-date pre-tax loss resulting in a tax benefit for the respective periods. 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 actual annual effective tax rate that is determined at the end of the year.

Discontinued Operations

In February 2013, we entered into a purchase and sale agreement pursuant to which we agreed to sell to an unrelated third-party 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 the buyer. In June 2013, this divestiture was completed for total consideration of approximately $177.6 million, with an additional $17.0 million paid to our non-affiliated investor partners in our affiliated partnerships. The sale resulted in a pre-tax loss of $2.3 million. Following the sale, 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 the three and six months ended June 30, 2013. The sale of our other non-core Colorado oil and gas properties did not meet the requirements to be accounted for as discontinued operations.

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.

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

Discontinued Operations	June 30, 2013 Three Months Ended	Six Months Ended
Production		
Crude oil (MBbls)	7.2	14.1
Natural gas (MMcf)	3,059.3	6,643.4
Crude oil equivalent (MBoe)	517.1	1,121.3

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

Net loss for the three months ended June 30, 2014 was $28.2 million compared to net income of $19.9 million for the same prior year period, while net loss for the six months ended June 30, 2014 and June 30, 2013 was $30.3 million and $19.5 million, respectively. Adjusted net loss, a non-U.S. GAAP financial measure, was $1.5 million for the three months ended June 30, 2014 compared to adjusted net income of $7.0 million for the same prior year period. Adjusted net income for the six months ended June 30, 2014 was $8.1 million compared to adjusted net loss of $13.4 million for the six months ended June 30, 2013. The quarter-over-quarter changes in net income (loss) are discussed above, with the most significant changes related to the increase in crude oil, natural gas and NGLs sales, general and administrative expense, DD&A expense and the loss from commodity price risk management activities in the second quarter. The year-over-year changes in net loss are discussed above, with the most significant changes related to the increase in crude oil, natural gas and NGLs sales, general and administrative expense, DD&A expense, and the decrease in impairment of crude oil and natural gas properties and loss from commodity price risk management activities. These same reasons for change similarly impacted adjusted net income (loss), with the exception of the net change in fair value of unsettled derivatives, adjusted for taxes, as this amount is 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 market transactions, asset sales and entrance into joint ventures, such as PDCM. For the six months ended June 30, 2014, our primary sources of liquidity were net cash flows from operating activities of $131.6 million and the remaining cash from the August 2013 equity transaction noted below. In light of our current focus on the Wattenberg Field and the Utica Shale, in July 2014, we signed a definitive agreement pursuant to which we agreed to sell our entire 50% ownership interest in PDCM to an unrelated third-party for aggregate consideration of approximately $250 million, subject to certain purchase price adjustments. See Note 15, Subsequent Events, to our condensed consolidated financial statements included elsewhere in this report for additional information. There can be no assurance we will be successful in closing the transaction. In addition, we may have greater than expected purchase price reductions.

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. 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 restrict us from entering into hedges that would exceed 85% of our expected future production from total proved reserves (proved developed producing, proved developed non-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, 2014, we had a working capital deficit of $167.8 million compared to a surplus of $112.4 million at December 31, 2013. The working capital deficit as of June 30, 2014 is a direct result of the reclassification of our 3.25% convertible senior notes due 2016 (the "Convertible Notes") to current liabilities and a decrease in cash and cash equivalents.

We ended June 2014 with cash and cash equivalents of $40.4 million and availability under our revolving credit facility and our proportionate share of PDCM's credit facility of $443.8 million, for a total liquidity position of $484.2

million, compared to $647.0 million at December 31, 2013. The decrease in liquidity of $162.8 million, or 25.2%, was primarily attributable to capital expenditures of $293.6 million during the six months ended June 30, 2014, offset in part by cash flows provided by operating activities of $131.6 million. With our current liquidity position and expected cash flows from operations, we believe that we have sufficient capital to fund our planned operations in 2014. Additionally, if we are successful in closing on the sale of our entire 50% ownership interest in PDCM, we expect to use the proceeds from the divestiture, along with internally generated cash flow and cash on hand, to fully fund our 2014 capital program and thereby further defer drawing on our revolving credit facility.

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 2014. 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. Pursuant to this shelf registration, we sold 5.2 million shares of our common stock in August 2013 in an underwritten public offering at a price to us of $53.37 per share.

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, change in fair value of unsettled derivatives, 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, 2014, we were in compliance with all debt covenants with a 2.0 times debt to EBITDAX ratio and a 2.0 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, 2014, we were in compliance with all covenants and expect to remain in compliance throughout the next year.

The Convertible Notes were convertible at the option of holders as of June 30, 2014. The conversion right was triggered on June 20, 2014, when the closing sale price of our common stock on the NASDAQ Global Select Market exceeded $55.12 (130% of the applicable conversion price) for the 20th trading day in the 30 consecutive trading days ending on June 30, 2014. As a result, the carrying value of the Convertible Notes, net of discount, was classified as a current liability as of June 30, 2014 in our condensed consolidated balance sheet. 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. In the event that a holder elects to convert its note, we expect to fund the cash settlement of any such conversion from working capital and/or borrowings under our revolving credit facility. The conversion right is not expected to have a material impact on our financial position. Through August 8, 2014, no holders of the Convertible Notes have elected to convert their notes.

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

Cash Flows

Operating Activities. Our net cash flows from operating activities are primarily impacted by commodity prices, production volumes, net settlements from our derivative positions, operating costs and general and administrative expenses. Cash flows from operating activities increased by $89.6 million for the six months ended June 30, 2014 compared to the six months ended June 30, 2013. The increase in cash provided by operating activities was primarily due to the increase in crude oil, natural gas and NGLs sales of $112.8 million and changes in assets and liabilities of $63.6 million related to the timing of cash payments and receipts. The increase was offset in part by the decrease in net settlements from our derivative positions of $31.1 million and increases in general and administrative expense of $33.4 million and production costs of $15.9 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 $26.0 million during the six months ended June 30, 2014 compared to the six months ended June 30, 2013. 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, increased by $23.9 million during the six months ended June 30, 2014 compared to the six months ended June 30, 2013. The increase was primarily the result of the increase in crude oil, natural gas and NGLs sales of $112.8 million, offset in part by the decrease in net settlements on derivatives of $31.1 million and an increase in general and administrative expense of $33.4 million and production costs of $15.9 million. See Reconciliation of Non-U.S. GAAP Financial Measures, below, for a more detailed discussion of non-U.S. GAAP financial measures.

Investing Activities. 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.

Cash flows from investing activities primarily consist of leasehold acquisitions, 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, 2014, our drilling program consisted of five drilling rigs operating in the liquid-rich horizontal Niobrara and Codell plays in our Wattenberg Field and one rig in the Utica Shale play. Net cash used in investing activities of $292.2 million during the six months ended June 30, 2014 was primarily related to cash utilized for our drilling operations of $293.6 million, offset in part by $1.4 million received from the sale of properties and equipment.

Financing Activities. Net cash from financing activities for the six months ended June 30, 2014 increased by approximately $50.4 million compared to the six months ended June 30, 2013. Net cash from financing activities of $7.7 million for the six months ended June 30, 2014 primarily represents our proportionate share of PDCM's draw on its credit facility.

Drilling Activity

The following table presents our net developmental and exploratory drilling activity for the periods shown. 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 or are waiting to be completed and/or for gas pipeline connection during the period.

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	Net Drilling Activity									
	Three Months Ended June 30,					Six Months Ended June 30,				
	2014			2013		2014			2013	
Operating Region/Area	Productive	In-Process	Dry	Productive	In-Process	Productive	In-Process	Dry	Productive	In-Process
Development Wells										
Wattenberg Field	24.5	30.7	1.0 (1)	10.2	15.6	36.2	30.7	1.7 (1)	18.0	15.6
Utica Shale	—	3.5	1.0 (1)	—	—	2.0	3.5	1.0 (1)	—	—
Marcellus Shale (2)	0.5	—	—	—	3.5	2.0	—	—	—	3.5
Total net development wells	25.0	34.2	2.0	10.2	19.1	40.2	34.2	2.7	18.0	19.1
Exploratory Wells										
Utica Shale	—	—	—	—	4.2	—	—	—	1.5	4.2
Total net exploratory wells	—	—	—	—	4.2	—	—	—	1.5	4.2
Total drilling activity	25.0	34.2	2.0	10.2	23.3	40.2	34.2	2.7	19.5	23.3

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(1) Represents two mechanical failures in the Wattenberg Field and one mechanical failure in the Utica Shale that resulted in the plugging and abandonment of the respective wells.
(2) Represents PDCM's drilling activity. On July 29, 2014, we signed a definitive agreement to sell our entire 50% interest in PDCM to an unrelated third-party. See Note 15, Subsequent Events, to our condensed consolidated financial statements included elsewhere in this report for additional information. There can be no assurance we will be successful in closing the transaction. In addition, we may have greater than expected purchase price reductions.

Off-Balance Sheet Arrangements

At June 30, 2014, we had no off-balance sheet arrangements, as defined under SEC rules, that have or are reasonably likely to have a material current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Commitments and Contingencies

See Note 9, Commitments and Contingencies, to the accompanying condensed consolidated financial statements included 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 required 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 2013 Form 10-K filed with the SEC on February 20, 2014.

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 significant 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 loss on commodity derivatives, less gain on commodity derivatives and net settlements on commodity derivatives, each adjusted for tax effect. We believe it is important to consider adjusted net income (loss), as well as net income (loss). We believe this measure often provides more transparency into our operating trends, such as production, prices, operating costs, net settlements from derivatives and related factors, without regard to changes in our net income (loss) from our mark-to-market adjustments resulting from net changes in the fair value of unsettled 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 loss on commodity derivatives, 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 gain on commodity derivatives and net settlements on commodity derivatives. 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), and should not be considered 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:

- operating performance and return on capital as compared to our peers;
- 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 each 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,	
	2014	2013	2014	2013
	(in millions)			
Adjusted cash flows from operations:				
Adjusted cash flows from operations	$55.0	$46.4	$124.7	$98.7
Changes in assets and liabilities	(3.9)	(48.6)	6.9	(56.7)
Net cash from operating activities	$51.1	$(2.2)	131.6	$42.0
Adjusted net income (loss):				
Adjusted net income (loss)	$(1.5)	$7.0	$8.1	$(13.4)
Gain (loss) on commodity derivative instruments	(53.4)	24.8	(80.6)	2.6
Net settlements on commodity derivative instruments	10.4	(4.0)	18.7	(12.5)
Tax effect of above adjustments	16.3	(7.9)	23.5	3.8
Net income (loss)	$(28.2)	$19.9	$(30.3)	$(19.5)
Adjusted EBITDA to net income (loss):				
Adjusted EBITDA	$62.7	$54.1	$139.2	$115.3
Gain (loss) on commodity derivative instruments	(53.4)	24.8	(80.6)	2.6
Net settlements on commodity derivative instruments	10.4	(4.0)	18.7	(12.5)
Interest expense, net	(12.9)	(13.1)	(25.5)	(26.4)
Income tax provision	20.5	(11.4)	21.9	10.0

Impairment of crude oil and natural gas properties	(0.9)	(1.5)	(1.9)	(48.0)
Depreciation, depletion and amortization	(53.7)	(27.8)	(100.4)	(58.0)
Accretion of asset retirement obligations	(0.9)	(1.2)	(1.7)	(2.5)
Net income (loss)	$(28.2)	$19.9	$(30.3)	$(19.5)
Adjusted EBITDA to net cash from operating activities:				
Adjusted EBITDA	$62.7	$54.1	$139.2	$115.3
Interest expense, net	(12.9)	(13.1)	(25.5)	(26.4)
Stock-based compensation	5.0	4.4	8.9	7.0
Amortization of debt discount and issuance costs	1.7	1.7	3.4	3.4
(Gain) loss on sale of properties and equipment	(0.4)	1.1	0.4	1.0
Other	(1.1)	(1.8)	(1.7)	(1.6)
Changes in assets and liabilities	(3.9)	(48.6)	6.9	(56.7)
Net cash from operating activities	$51.1	$(2.2)	$131.6	$42.0

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Ballot Initiative Update

As discussed in the “Risk Factors” section of the 2013 Form 10-K, certain interest groups in Colorado opposed to oil and natural gas development generally, or hydraulic fracturing in particular, have advanced various options for ballot initiatives aimed at significantly limiting or preventing oil and natural gas development. The initiative proponents ultimately submitted signatures for only two such initiatives, which would amend the state constitution to establish, respectively, an “environmental bill of rights,” and a 2000-foot statewide drilling setback from occupied structures. As part of a compromise negotiated by Governor John Hickenlooper, both initiatives were subsequently withdrawn and they will not appear on the November 2014 ballot.

Pursuant to this compromise, Governor Hickenlooper will create a task force charged with crafting recommendations to help minimize land use conflicts relating to the location of oil and gas facilities. The task force will be composed of 18 individuals representing a variety of interests involved in and affected by oil and gas development. The task force will have the power to make recommendations to the state legislature. We cannot predict the outcome of the processes, and proposals to be formulated, by the task force.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market-Sensitive Instruments and Risk Management

We are exposed to market risks associated with interest 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 7.75% senior notes due 2022 and our Convertible 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, 2014, 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, 2014 was $51.1 million with an average interest rate of 0.4%. Based on a sensitivity analysis of our interest bearing deposits as of June 30, 2014, it was estimated that if market interest rates would have increased by 1%, the impact on interest income for the six months ended June 30, 2014 would result in a change of $0.3 million.

As of June 30, 2014, excluding the $11.7 million irrevocable standby letter of credit, we had no outstanding draws on our revolving credit facility and, representing our proportionate share, $47.0 million on PDCM's revolving 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, 2014 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. Pursuant to established policies and procedures, we manage a portion of the risks associated with these market fluctuations using derivative instruments. These instruments help us predict with greater certainty the effective crude oil and natural gas prices we will receive for our hedged production. We believe that our derivative policies and procedures are effective in achieving our risk management objectives.

The following table presents our derivative positions related to crude oil and natural gas sales in effect as of June 30, 2014:

	Collars			Fixed-Price Swaps		Basis Protection Swaps		
Commodity/ Index/ Maturity Period	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted-Average Contract Price		Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted-Average Contract Price	Quantity (BBtu) (1)	Weighted-Average Contract Price	Fair Value June 30, 2014 (2) (in millions)
		Floors	Ceilings					
Natural Gas								
NYMEX								
2014	—	$ —	$ —	9,095.0	$ 4.17	5,020.0	$ (0.19)	$ (2.6)
2015	5,860.0	4.00	4.48	12,950.0	4.10	3,420.0	(0.25)	(1.9)

2016	4,820.0	4.03	4.48	13,000.0	4.00	—	—	(3.1)
2017	1,630.0	4.25	5.00	625.0	4.22	—	—	0.1
CIG								
2014	—	—	—	2,524.0	3.98	—	—	(1.1)
2015	—	—	—	2,730.0	4.01	—	—	0.3
Total Natural Gas	12,310.0			40,924.0		8,440.0		(8.3)
Crude Oil								
NYMEX								
2014	414.0	82.37	101.99	1,804.0	90.77	—	—	(23.2)
2015	686.0	85.63	96.86	4,514.0	89.12	—	—	(35.4)
2016	1,740.0	77.59	97.55	1,080.0	89.87	—	—	(5.5)
Total Crude Oil	2,840.0			7,398.0		—		(64.1)
Total Natural Gas and Crude Oil								$(72.4)

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

(2) Approximately 40.8% of the fair value of our derivative assets and 10% 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 average NYMEX and CIG closing prices for crude oil and natural gas for the periods identified, as well as average sales prices we realized for our crude oil, natural gas and NGLs production:

	Six Months Ended June 30, 2014	Year Ended December 31, 2013
Average Index Closing Price:		
Crude oil (per Bbl)		
NYMEX	$100.84	$97.97
Natural gas (per MMBtu)		
CIG	$4.52	$3.45
NYMEX	4.80	3.65
Average Sales Price Realized:		
Excluding net settlements on derivatives		
Crude oil (per Bbl)	$88.94	$89.92
Natural gas (per Mcf)	4.29	3.29
NGLs (per Bbl)	31.24	27.97

Based on a sensitivity analysis as of June 30, 2014, 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 the fair value of our derivative positions of $110.3 million; whereas a 10% decrease in prices would have resulted in an increase in fair value of $107.1 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. While we believe that our credit risk analysis and monitoring procedures are reasonable, no amount of analysis can assure performance by our counterparties.

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 our credit risk exposure with 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 segment.

Our derivative financial instruments may expose us to the 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 the creditworthiness of our counterparties through our credit committee, which utilizes a number of qualitative and quantitative tools to assess credit risk and takes mitigative actions if deemed necessary. While we believe that our monitoring procedures are reasonable, no amount of analysis can assure performance by a financial institution. In addition, disruption in the credit markets may have a significant adverse impact on a number of financial institutions. To date, we have had no material counterparty default losses from our derivative financial instruments. See Note 4, Derivative Financial Instruments, to our consolidated financial statements included elsewhere in this report for more detail on our derivative financial instruments.

Disclosure of Limitations

Because the information above included only those exposures that existed at June 30, 2014, 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.

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ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of June 30, 2014, 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, 2014.

Changes in Internal Control over Financial Reporting

During the three months ended June 30, 2014, 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

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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 2013 Form 10-K. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

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, 2014	12,611	$62.14
May 1 - 31, 2014	15,662	61.76
June 1 - 30, 2014	8,576	63.57
Total second quarter purchases	36,849	62.31

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

ITEM 3. DEFAULTS UPON SENIOR SECURITIES - None.

ITEM 4. MINE SAFETY DISCLOSURES - Not applicable.

ITEM 5. OTHER INFORMATION - None.

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PDC ENERGY, INC.

ITEM 6. EXHIBITS

		Incorporated by Reference				
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
3.1	Fourth Amended and Restated Articles of Incorporation of PDC Energy, Inc. (the "Company")	8-K	000-07246	3.1	6/10/2014	
10.1	Consulting Agreement with James M. Trimble, Chief Executive Officer and President, dated as of June, 18, 2014.					X
10.2	Purchase and Sale Agreement by and among the Company, LR-Mountaineer Holdings, L.P., PDC Mountaineer, LLC and PDC Mountaineer Holdings, LLC, dated July 29, 2014.	8-K	000-07246	2.1	8/1/2014	
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					X
101.SCH	XBRL Taxonomy Extension Schema Document					X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document					X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document					X
101.LAB	XBRL Taxonomy Extension Label Linkbase Document					X
101.PRE						X

XBRL Taxonomy Extension Presentation Linkbase Document

* Furnished herewith.

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SIGNATURES

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

PDC Energy, Inc.
(Registrant)

Date: August 8, 2014

/s/ James M. Trimble
James M. Trimble
Chief Executive Officer
(principal executive officer)

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

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