PDC ENERGY, INC.
Form 10-Q
November 05, 2015

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 September 30, 2015

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 001-37419
PDC ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	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: 40,107,524 shares of the Company's Common Stock ($0.01 par value) were outstanding as of October 16, 2015.

PDC ENERGY, INC.

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act") and Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") regarding our business, financial condition, results of operations and prospects. All statements other than statements of historical facts included in and incorporated by reference into this report are "forward-looking statements" within the meaning of the safe harbor provisions of the United States ("U.S.") Private Securities Litigation Reform Act of 1995. Words such as expects, anticipates, intends, plans, believes, seeks, estimates and similar expressions or variations of such words are intended to identify forward-looking statements herein. These statements relate to, among other things: estimated future production (including the components of such production), sales, expenses, cash flows and liquidity; estimated crude oil, natural gas and natural gas liquids (“NGLs”) reserves, including 2015 year-end reserves; expected 2015 capital forecast allocations, including revised capital and production forecasts and that we expect to meet or exceed the high end of our range; anticipated increased 2015 capital projects and expenditures; expected year-end exit rates; the impact of prolonged depressed commodity prices; the Utica Shale impairment and other potential future impairments; availability of sufficient funding for our 2015 capital program and sources of that funding; future exploration, drilling and development activities, including our expected rig count in both the Utica Shale and Wattenberg Field; expectation of cash flows in 2015 and 2016; potential additional revisions to our 2015 capital and production forecast; anticipated reductions in our 2015 cost structure; the expiration of certain leases and our current development plan in the Utica Shale; our evaluation method of our customers' and derivative counterparties' credit risk, including certain of our gas marketing customers; our expected positive net settlements on our derivative positions and effect on cash flow in 2015; effectiveness of our derivative program in providing a degree of price stability; the impact of high line pressures and the timing, availability, cost and effect of additional midstream facilities and services going forward; expected differentials; compliance with debt covenants; expected funding sources for anticipated net settlement of our 3.25% convertible senior notes due 2016; the impact of litigation on our results of operations and financial position; that we do not expect to pay dividends in the foreseeable future; 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. Forward-looking statements are always subject to risks and uncertainties, and become subject to greater levels of risk and uncertainty as they address matters further into the future. Throughout this report or accompanying quarterly materials, we may use the terms “outlook,” “projection” or similar terms or expressions, or indicate that we have “modeled” certain future scenarios. We typically use these terms to indicate our current thoughts on possible outcomes relating to our business or the industry in periods beyond the current fiscal year. In addition to being subject to additional levels of uncertainty generally, forward-looking statements regarding such prospective matters do not necessarily reflect the outcomes we view as the most likely to occur, but instead are shown to illustrate aspects of our business in the context of a variety of scenarios we believe to be plausible.

Important factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- 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 and the risk of an extended period of depressed prices;
- 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 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;
- 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, 2014 (the

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"2014 Form 10-K"), filed with the U.S. Securities and Exchange Commission ("SEC") on February 19, 2015, 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 PDC Mountaineer, LLC ("PDCM"), a joint venture owned, until October 2014, 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)

	September 30, 2015	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$3,690	$16,066
Accounts receivable, net	106,776	131,204
Fair value of derivatives	208,144	187,495
Prepaid expenses and other current assets	7,683	5,954
Total current assets	326,293	340,719
Properties and equipment, net	1,873,327	1,800,186
Assets held for sale	2,874	2,874
Fair value of derivatives	73,049	112,819
Other assets	68,767	83,990
Total Assets	$2,344,310	$2,340,588
Liabilities and Shareholders' Equity		
Liabilities		
Current liabilities:		
Accounts payable	$65,337	$130,321
Production tax liability	26,159	21,314
Fair value of derivatives	2,245	570
Funds held for distribution	32,780	27,186
Current portion of long-term debt	112,063	—
Accrued interest payable	19,881	9,109
Deferred income taxes	52,188	59,174
Other accrued expenses	25,146	62,717
Total current liabilities	335,799	310,391
Long-term debt	550,000	664,923
Deferred income taxes	87,907	125,693
Asset retirement obligation	71,616	71,992
Fair value of derivatives	723	197
Other liabilities	18,529	30,033
Total liabilities	1,064,574	1,203,229
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, 40,121,608 and 35,927,985 issued as of September 30, 2015 and December 31, 2014, respectively	401	359
Additional paid-in capital	903,038	689,209

Retained earnings	377,400	448,702
Treasury shares - at cost, 22,418 and 21,643 as of September 30, 2015 and December 31, 2014, respectively	(1,103)	(911)
Total shareholders' equity	1,279,736	1,137,359
Total Liabilities and Shareholders' Equity	$2,344,310	$2,340,588

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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Revenues				
Crude oil, natural gas and NGLs sales	$104,483	$120,526	$275,520	$371,556
Sales from natural gas marketing	2,580	13,297	8,336	62,649
Commodity price risk management gain, net	123,549	90,213	141,170	12,661
Well operations, pipeline income and other	488	520	1,666	1,650
Total revenues	231,100	224,556	426,692	448,516
Costs, expenses and other				
Production costs	25,484	22,754	71,129	64,611
Cost of natural gas marketing	2,781	13,347	8,875	62,645
Exploration expense	252	190	812	773
Impairment of crude oil and natural gas properties	153,535	1,863	158,792	3,621
General and administrative expense	18,528	34,625	55,875	96,549
Depreciation, depletion and amortization	80,947	49,640	206,873	142,165
Accretion of asset retirement obligations	1,594	861	4,742	2,542
(Gain) loss on sale of properties and equipment	(74)	21	(302)	577
Total cost, expenses and other	283,047	123,301	506,796	373,483
Income (loss) from operations	(51,947)	101,255	(80,104)	75,033
Interest expense	(12,092)	(11,821)	(35,384)	(36,199)
Interest income	1,378	39	3,626	309
Income (loss) from continuing operations before income taxes	(62,661)	89,473	(111,862)	39,143
Provision for income taxes	21,167	(35,396)	40,560	(15,852)
Income (loss) from continuing operations	(41,494)	54,077	(71,302)	23,291
Income (loss) from discontinued operations, net of tax	—	(80)	—	392
Net income (loss)	$(41,494)	$53,997	$(71,302)	$23,683
Earnings per share:				
Basic				
Income (loss) from continuing operations	$(1.04)	$1.51	$(1.84)	$0.65
Income (loss) from discontinued operations, net of tax	—	—	—	0.01
Net income (loss)	$(1.04)	$1.51	$(1.84)	$0.66
Diluted				
Income (loss) from continuing operations	$(1.04)	$1.47	$(1.84)	$0.63
Income (loss) from discontinued operations, net of tax	—	—	—	0.01
Net income (loss)	$(1.04)	$1.47	$(1.84)	$0.64
Weighted-average common shares outstanding:				
Basic	40,085	35,834	38,837	35,763

Diluted	40,085	36,828	38,837	36,831

See accompanying Notes to Condensed Consolidated Financial Statements

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

	Nine Months Ended September 30, 2015	2014
Cash flows from operating activities:		
Net income (loss)	$(71,302)	$23,683
Adjustments to net income (loss) to reconcile to net cash from operating activities:		
Net change in fair value of unsettled derivatives	21,322	(34,323)
Depreciation, depletion and amortization	206,873	151,293
Impairment of crude oil and natural gas properties	158,792	4,054
Accretion of asset retirement obligation	4,742	2,582
Stock-based compensation	14,278	13,111
(Gain) loss on sale of properties and equipment	(302)	384
Amortization of debt discount and issuance costs	5,308	5,206
Deferred income taxes	(44,770)	14,981
Non-cash interest income	(3,624)	—
Other	2,241	(759)
Changes in assets and liabilities	(10,552)	21,753
Net cash from operating activities	283,006	201,965
Cash flows from investing activities:		
Capital expenditures	(489,036)	(451,081)
Proceeds from sale of properties and equipment	319	1,587
Net cash from investing activities	(488,717)	(449,494)
Cash flows from financing activities:		
Proceeds from sale of common stock, net of issuance costs	202,851	—
Proceeds from revolving credit facility	325,000	136,750
Repayment of revolving credit facility	(331,000)	(61,000)
Other	(3,516)	(2,726)
Net cash from financing activities	193,335	73,024
Net change in cash and cash equivalents	(12,376)	(174,505)
Cash and cash equivalents, beginning of period	16,066	193,243
Cash and cash equivalents, end of period	$3,690	$18,738
Supplemental cash flow information:		
Cash payments for:		
Interest, net of capitalized interest	$23,467	$24,933
Income taxes	9,936	1,800
Non-cash investing and financing activities:		
Change in accounts payable related to purchases of properties and equipment	$(68,529)	$19,320
Change in asset retirement obligation, with a corresponding change to crude oil and natural gas properties, net of disposals	1,642	500
Purchase of properties and equipment under capital leases	1,479	—

See accompanying Notes to Condensed Consolidated Financial Statements

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PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
September 30, 2015
(Unaudited)

NOTE 1 - NATURE OF OPERATIONS AND BASIS OF PRESENTATION

PDC Energy, Inc. (the "Company," "we," "us," or "our") 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 and the Utica Shale in southeastern Ohio. Our operations in the Wattenberg Field are focused in the horizontal Niobrara and Codell plays and our Ohio operations are focused in the Utica Shale play. As of September 30, 2015, we owned an interest in approximately 2,950 gross wells. We are engaged in two business segments: Oil and Gas Exploration and Production and Gas Marketing. In October 2014, we sold our entire 50% ownership interest in our joint venture, PDCM, to an unrelated third-party.

The accompanying unaudited condensed consolidated financial statements include the accounts of PDC, our wholly-owned subsidiary Riley Natural Gas ("RNG"), our proportionate share of our four affiliated partnerships and, for the three and nine months ended September 30, 2014, our proportionate share of PDCM. 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 2014 Form 10-K. Our results of operations and cash flows for the three and nine months ended September 30, 2015 are not necessarily indicative of the results to be expected for the full year or any other future period.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") and the International Accounting Standards Board 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: (1) identify the contract with the customer, (2) identify the separate performance obligations in the contract, (3) determine the transaction price, (4) allocate the transaction price to separate performance obligations and (5) recognize revenue when (or as) each performance obligation is satisfied. In August 2015, the FASB deferred the effective date of the revenue standard to annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. The revenue standard can be adopted under the full retrospective method or simplified transition method. Entities are permitted to adopt the revenue standard early, beginning with annual reporting periods after December 15, 2016. We are currently evaluating the impact these changes may have on our condensed consolidated financial statements.

In August 2014, the FASB issued a new standard related to the disclosure of uncertainties about an entity's ability to continue as a going concern. The new standard will explicitly require management to assess an entity's ability to continue as a going concern every reporting period and to provide related footnote disclosures in certain circumstances. The new standard will be effective for all entities in the first annual period ending after December 15, 2016, with early adoption permitted. Adoption of this guidance is not expected to have a significant impact on our condensed consolidated financial statements.

In November 2014, the FASB issued an update to accounting for derivatives and hedging instruments. The update clarifies how current accounting guidance should be interpreted in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. Specifically, the accounting update clarifies that an entity should consider all relevant terms and features, including the embedded derivative feature being evaluated for bifurcation, in evaluating the nature of the host contract. Furthermore, the update clarifies that no single term or feature would necessarily determine the economic characteristics and risks of the host contract. Rather, the nature of the host contract depends upon the economic characteristics and risks of the entire hybrid financial instrument. The assessment of the substance of the relevant terms and features should incorporate a consideration of the characteristics of the terms and features themselves, the circumstances under which the hybrid financial instrument was issued or acquired, and the potential outcomes of the hybrid financial instrument, as well as the likelihood of those potential outcomes. The accounting update is effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. We are currently evaluating the impact these changes may have on our condensed consolidated financial statements.

In January 2015, the FASB issued new accounting guidance eliminating from current accounting guidance the concept of extraordinary items, which, among other things, required an entity to segregate extraordinary items considered to be unusual and infrequent from the results of ordinary operations and show the item separately in the income statement, net of tax, after income from continuing operations. This guidance is effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. Adoption of this guidance is not expected to have a significant impact on our condensed consolidated financial statements.

In February 2015, the FASB issued an accounting update modifying existing consolidation guidance for reporting organizations that are required to evaluate whether they should consolidate certain legal entities. The amendments in this update are effective for fiscal years and interim periods within those years beginning after December 15, 2015, and require either a retrospective or a modified retrospective approach to adoption. Early adoption is permitted. Adoption of this guidance is not expected to have a significant impact on our condensed consolidated financial statements.

In April 2015, the FASB issued an accounting update simplifying the presentation of debt issuance costs and requiring that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The update did not affect the recognition and measurement guidance for debt issuance costs. This guidance is effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. Adoption of this guidance is not expected to have a significant impact on our condensed consolidated financial statements.

In July 2015, the FASB issued an accounting update requiring all entities to measure inventory at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This guidance is effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016. Adoption of this guidance is not expected to have a significant impact on our condensed consolidated financial statements.

In September 2015, the FASB issued an accounting update requiring adjustments to provisional amounts that are identified during the measurement period of a business combination to be recognized in the reporting period in which the adjustment amounts are determined. The accounting update also requires an entity to present separately on the face of the income statement, or disclose in the notes, the portion of the amount recorded in current-period earnings, by line item, that would have been recorded in previous reporting periods if the adjustment to the estimated amounts had been recognized as of the acquisition date. This guidance is effective for public entities for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. The accounting update should be applied prospectively to adjustments to provisional amounts that occur after the effective date with earlier application permitted for financial statements that have not been issued. Adoption of this guidance is not expected to have a significant impact 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.

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

Our fixed-price swaps, basis swaps and physical purchases are included in Level 2 and our collars 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:

	September 30, 2015			December 31, 2014		
	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	$197,331	$83,862	$281,193	$237,939	$62,356	$300,295
Basis protection derivative contracts	—	—	—	19	—	19
Total assets	197,331	83,862	281,193	237,958	62,356	300,314
Liabilities:						
Commodity-based derivative contracts	482	—	482	742	—	742
Basis protection derivative contracts	2,486	—	2,486	25	—	25
Total liabilities	2,968	—	2,968	767	—	767
Net asset	$194,363	$83,862	$278,225	$237,191	$62,356	$299,547

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Fair value, net asset (liability), beginning of period	$58,256	$(6,967)	$62,356	$1,111
Changes in fair value included in statement of operations line item:				
Commodity price risk management gain, net	38,085	12,758	42,525	3,961
Sales from natural gas marketing	51	2	51	(24)
Settlements included in statement of operations line items:				
Commodity price risk management gain (loss), net	(12,530)	142	(21,063)	882
Sales from natural gas marketing	—	(3)	(7)	2
Fair value, net asset end of period	$83,862	$5,932	$83,862	$5,932
Net change in fair value of unsettled derivatives included in statement of operations line item:				
Commodity price risk management gain, net	$34,564	$11,831	$31,794	$673

Sales from natural gas marketing	—	1	—	(2)
Total	$34,564	$11,832	$31,794	$671

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. There has been no change in the methodology we apply to measure the fair value 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, excluding the current portion of long-term debt, 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 liability related to this plan, which was included in other liabilities on the condensed consolidated balance sheets, was immaterial as of September 30, 2015 and December 31, 2014.

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

The portion of our long-term debt related to our revolving credit facility approximates fair value due to the variable nature of related interest rates. We have not elected to account for the portion of our debt related to our senior notes under the fair value option; however, as of September 30, 2015, 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 $161.4 million, or 140.3% of par value, and the portion related to our 7.75% senior notes due 2022 to be $496.3 million, or 99.3% of par value. We determined these valuations based upon measurements of trading activity and broker and/or dealer quotes, respectively, which are published market prices, and therefore are Level 2 inputs.

The carrying value of our capital lease obligations approximates fair value as it represents the present value of future lease payments.

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 September 30, 2015, taking into account the estimated likelihood of nonperformance.

The following table presents the counterparties that expose us to credit risk as of September 30, 2015 with regard to our derivative assets:

Counterparty Name	Fair Value of Derivative Assets (in thousands)
JP Morgan Chase Bank, N.A (1)	$77,743
Canadian Imperial Bank of Commerce (1)	72,977
Bank of Nova Scotia (1)	41,354
Wells Fargo Bank, N.A. (1)	38,973
NATIXIS (1)	32,941
Key Bank N.A. (1)	11,163
Other lenders in our revolving credit facility	6,042
Total	$281,193

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(1)Major lender in our revolving credit facility. See Note 7, Long-Term Debt.

Note Receivable. The following table presents information regarding our note receivable outstanding as of September 30, 2015:

	Amount (in thousands)
Note receivable:	
Principal outstanding, December 31, 2014	$39,707
Paid-in-kind interest	2,430

Principal outstanding, September 30, 2015	$42,137

In October 2014, we sold our entire 50% ownership interest in PDCM to an unrelated third-party. See Note 13, Assets Held for Sale, Divestitures and Discontinued Operations, for additional information regarding the sale. As part of the consideration, we received a promissory note (the “Note”) for a principal sum of $39.0 million, bearing interest at varying rates beginning at 8%, and increasing annually. Pursuant to the Note agreement, interest shall be paid quarterly, in arrears, commencing in December 2014 and continuing on the last business day of each fiscal quarter thereafter. At the option of the issuer of the Note, an unrelated third-party, interest can be paid-in-kind (the “PIK Interest”) and any such PIK Interest will be added to the outstanding principal amount of the Note. As of September 30, 2015, the issuer of the Note had elected the PIK Interest option. The principal and any unpaid interest shall be due and payable in full in September 2020 and can be prepaid in whole or in part at any time, and in certain circumstances must be repaid prior to maturity. Any such prepayment will be made without premium or penalty. The Note is secured by a pledge of stock in certain subsidiaries of the unrelated third-party, debt securities and other assets.

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Under the effective interest method, we recognized $1.1 million and $3.4 million of interest income for the three and nine months ended September 30, 2015, respectively, of which $0.8 million and $2.4 million, respectively, was PIK Interest. As of September 30, 2015, the $42.1 million outstanding balance on the Note was included in the condensed consolidated balance sheet line item other assets.

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 September 30, 2015, 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 2018 for a total of 73,176 BBtu of natural gas and 6,701 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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PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following table presents the balance sheet location and fair value amounts of our derivative instruments on the condensed consolidated balance sheets:

Derivative instruments:		Balance sheet line item	Fair Value September 30, 2015 (in thousands)	December 31, 2014
Derivative assets:	Current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	$207,731	$186,886
	Related to natural gas marketing	Fair value of derivatives	413	590
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	—	19
			208,144	187,495
	Non-current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	72,950	112,599
	Related to natural gas marketing	Fair value of derivatives	99	220
			73,049	112,819
Total derivative assets			$281,193	$300,314
Derivative liabilities:	Current			
	Commodity contracts			
	Related to natural gas marketing	Fair value of derivatives	$393	$545
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	1,852	25
			2,245	570
	Non-current			
	Commodity contracts			
	Related to natural gas marketing	Fair value of derivatives	89	197
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	634	—
			723	197
Total derivative liabilities			$2,968	$767

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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Commodity price risk management gain, net				
Net settlements	$67,993	$(4,459)	$162,454	$(21,511)
Net change in fair value of unsettled derivatives	55,556	94,672	(21,284)	34,172
Total commodity price risk management gain, net	$123,549	$90,213	$141,170	$12,661
Sales from natural gas marketing				
Net settlements	$165	$210	$561	$(376)
Net change in fair value of unsettled derivatives	(5)	170	(298)	123
Total sales from natural gas marketing	$160	$380	$263	$(253)
Cost of natural gas marketing				
Net settlements	$(157)	$(182)	$(531)	$502
Net change in fair value of unsettled derivatives	(5)	(191)	260	(199)
Total cost of natural gas marketing	$(162)	$(373)	$(271)	$303

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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 September 30, 2015	Derivative 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	$281,193	$(2,548)	$278,645
Liability derivatives:			
Derivative instruments, at fair value	$2,968	$(2,548)	$420

As of December 31, 2014	Derivative 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	$300,314	$(29)	$300,285
Liability derivatives:			
Derivative instruments, at fair value	$767	$(29)	$738

NOTE 5 - PROPERTIES AND EQUIPMENT

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

	September 30, 2015	December 31, 2014
	(in thousands)	
Properties and equipment, net:		
Crude oil and natural gas properties		
Proved	$2,712,759	$2,267,165
Unproved	82,280	188,206
Total crude oil and natural gas properties	2,795,039	2,455,371
Equipment and other	32,119	29,562
Land and buildings	9,016	9,015

Construction in progress	99,008	137,937
Properties and equipment, at cost	2,935,182	2,631,885
Accumulated DD&A	(1,061,855)	(831,699)
Properties and equipment, net	$1,873,327	$1,800,186

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Continuing operations:				
Impairment of proved and unproved properties	$150,344	$—	$150,344	$—
Amortization of individually insignificant unproved properties	3,191	1,085	8,448	2,843
Other	—	778	—	778
Total continuing operations	153,535	1,863	158,792	3,621
Discontinued operations:				
Amortization of individually insignificant unproved properties	—	274	—	433
Total impairment of crude oil and natural gas properties	$153,535	$2,137	$158,792	$4,054

Due to a significant decline in commodity prices and a decrease in net-back realizations, we experienced a triggering event that required us to assess our crude oil and natural gas properties for possible impairment during the third quarter of 2015. As a result of our assessment, we recorded an impairment charge of $150.3 million to write-down our Utica Shale proved and unproved properties. Of this impairment charge, $24.7 million was recorded to write-down certain capitalized well costs on our Utica Shale proved producing properties. This impairment charge represented the amount by which the carrying value of these crude oil and natural gas properties exceeded the estimated fair value. The estimated fair value of approximately $27.9 million, excluding estimated salvage value, was determined based on estimated future discounted net cash flows, a Level 3 input, using estimated production and prices at which we reasonably expect the crude oil and natural gas will be sold. Additionally, as a result of the current outlook for future commodity prices, we recorded an impairment charge of $125.6 million to write-down all of our Utica Shale lease acquisition costs and pad development costs for pads not in production. These impairment charges were included in the condensed consolidated statements of operations line item impairment of crude oil and natural gas properties.

NOTE 6 - INCOME TAXES

We evaluate and update our estimated annual effective income tax rate on a quarterly basis based on current and forecasted operating results and tax laws. 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 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 nine months ended September 30, 2015 was a 33.8% and 36.3% benefit on loss, respectively, compared to a 39.6% and 40.5% provision on income for the three and nine months ended September 30, 2014, respectively.

The effective tax rates for the three and nine months ended September 30, 2015 include discrete tax expense of $0.3 million. This discrete tax expense arose based upon the final actual 2014 tax return expense differing from the previous year's estimated tax provision amount and the loss of a state deferred tax asset due to ceasing operations within that state. The effective rate for the three and nine months ended September 30, 2015 would have been 34.2% and 36.5%, respectively, without the inclusion of discrete items. This effective rate is based upon a full year forecasted tax benefit on loss and is greater than the statutory rate, primarily due to state taxes, percentage depletion and domestic production deduction, partially offset by nondeductible expenses that consist primarily of officers' compensation and government lobbying expenses.

The effective tax rates for the three and nine months ended September 30, 2014 include discrete tax expense of $0.6 million. This discrete tax expense arose based upon the final actual 2013 tax return expense differing from the previous year's estimated tax provision amount. The effective rate for the three and nine months ended September 30, 2014 would have been 38.8% and 38.9%, respectively, without the inclusion of discrete items. This effective tax rate is based upon a full year forecasted tax provision on income and is greater than the statutory rate primarily due to state taxes and nondeductible officers' compensation, partially offset by percentage depletion and domestic production deduction.

As of September 30, 2015, we had no liability for unrecognized tax benefits. 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 any state income tax examinations. We continue voluntary participation in the Internal Revenue Service's ("IRS") Compliance Assurance Program for the 2014 and 2015 tax years. We have received a partial acceptance "no change" notice from the IRS for our filed 2014 federal tax return and expect to receive a full acceptance notice after the IRS's post filing review is completed.

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NOTE 7 - LONG-TERM DEBT

Long-term debt consists of the following:

	September 30, 2015	December 31, 2014
	(in thousands)	
Senior notes:		
3.25% Convertible senior notes due 2016:		
Principal amount	$115,000	$115,000
Unamortized discount	(2,937)	(6,077)
3.25% Convertible senior notes due 2016, net of discount	112,063	108,923
7.75% Senior notes due 2022	500,000	500,000
Total senior notes	612,063	608,923
Revolving credit facility	50,000	56,000
Total debt	662,063	664,923
Less current portion of long-term debt	112,063	—
Long-term debt	$550,000	$664,923

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 Convertible 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 Convertible Notes using an effective interest rate of 7.4%. As the stated maturity for payment of principal is May 2016, 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 September 30, 2015.

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. Per the terms of the Convertible Notes, we have currently elected the 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 not convertible at the option of holders as of September 30, 2015. Notwithstanding the inability to convert, the “if-converted” value of the Convertible Notes as of September 30, 2015 exceeded the aggregate principal amount by approximately $28.8 million.

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 2022 Senior Notes contains customary restrictive incurrence covenants. Capitalized debt issuance costs are being amortized as interest expense over the life of the 2022 Senior Notes using the effective interest method.

As of September 30, 2015, 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 Facility

Revolving Credit Facility. In September 2015, we entered into a Second Amendment to 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 extends the maturity of the revolving credit facility to May 2020. 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 September 30, 2015, the fall 2015 semi-annual redetermination resulted in the reaffirmation of our borrowing base at $700 million; however, we have elected to maintain the aggregate commitment at $450 million. The borrowing base is based on, among other things, the loan value assigned to the proved reserves attributable to our crude oil and natural gas interests, excluding proved reserves attributable to 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. Our affiliated partnerships are not guarantors of our obligations under the revolving credit facility.

We had $50.0 million outstanding on our revolving credit facility as of September 30, 2015, compared to $56.0 million outstanding as of December 31, 2014. The weighted-average interest rate on the outstanding balance on our revolving credit facility, exclusive of fees on the unused commitment and the letter of credit noted below, was 2.7% and 4.1% per annum as of September 30, 2015 and December 31, 2014, respectively.

As of September 30, 2015, RNG 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 currently expires in September 2016 and is automatically extended annually in accordance with the letter of credit's terms and conditions. The letter of credit reduces the amount of available funds under our revolving credit facility by an amount equal to the letter of credit. As of September 30, 2015, the available funds under our revolving credit facility, including the reduction for the $11.7 million letter of credit, was $388.3 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 September 30, 2015, we were in compliance with all the revolving credit facility covenants and expect to remain in compliance throughout the next 12-month period.

NOTE 8 - CAPITAL LEASES

Beginning in the first quarter of 2015, we entered into non-cancelable lease agreements for vehicles utilized by our operations and field personnel. Each lease agreement has a term of three years and is being accounted for as a capital lease, as the present value of minimum monthly lease payments, including the residual value guarantee, exceeds 90% of the fair value of the leased vehicles at inception of the lease.

The following table presents leased vehicles under capital leases as of September 30, 2015:

	Amount (in thousands)
Vehicles	$1,479
Accumulated depreciation	(121)
	$1,358

Future minimum lease payments by year and in the aggregate, under non-cancelable capital leases with terms of one year or more, consist of the following:

For the Twelve Months Ending September 30,	Amount (in thousands)
2016	$447
2017	454
2018	743
	1,644
Less executory cost	(72)
Less amount representing interest	(215)
Present value of minimum lease payments	$1,357

Short-term capital lease obligations	$315
Long-term capital lease obligations	1,042
	$1,357

Short-term capital lease obligations are included in other accrued expenses on the condensed consolidated balance sheets. Long-term capital lease obligations are included in other liabilities on the condensed consolidated balance sheets.

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NOTE 9 - ASSET RETIREMENT OBLIGATIONS

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

	Amount (in thousands)
Balance at beginning of period, January 1, 2015	$73,855
Obligations incurred with development activities	1,642
Accretion expense	4,742
Obligations discharged with asset retirements	(3,163)
Balance end of period, September 30, 2015	77,076
Less current portion	(5,460)
Long-term portion	$71,616

Short-term asset retirement obligations are included in other accrued expenses on the condensed consolidated balance sheets.

NOTE 10 - COMMITMENTS AND CONTINGENCIES

Firm Transportation, Processing and Sales Agreements. We enter into contracts that provide firm transportation, sales and processing agreements on pipeline systems through which we transport or sell crude oil and natural gas. Satisfaction of the volume requirements includes volumes produced by us, purchased from third parties and produced by our affiliated partnerships 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. As commodity prices continue to remain depressed, certain customers under our Gas Marketing segment have begun and will continue to experience financial distress, which has led to certain contractual defaults. To date, we have had no material counterparty default losses.

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

	For the Twelve Months Ending September 30,						
Area	2016	2017	2018	2019	2020 and Through Expiration	Total	Expiration Date
Natural gas (MMcf)							
Appalachian Basin	7,136	7,117	7,117	7,117	20,480	48,967	August 31, 2022
Utica Shale	2,745	2,738	2,737	2,738	10,500	21,458	July 22, 2023
Total	9,881	9,855	9,854	9,855	30,980	70,425	
Crude oil (MBbls)							
Wattenberg Field	2,420	2,413	2,413	2,413	1,813	11,472	June 30, 2020
	$17,623	$17,473	$16,326	$16,326	$21,312	$89,060	

Dollar commitment (in thousands)

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.

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 unit holders of 12 former limited partnerships, related to its repurchase of the 12 partnerships, which were formed beginning in late 2002 through 2005. The mergers were completed in 2010 and 2011. The action was filed in U.S. District Court for the Central District of California and was titled Schulein v. Petroleum Development Corp. The complaint primarily alleged 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.

In October 2014, the Company and plaintiffs’ counsel reached a settlement agreement. That settlement agreement was signed in December 2014 and was given final court approval in March 2015. Under this settlement agreement, the plaintiffs received a cash payment of $37.5 million in January 2015, of which the Company paid $31.5 million and insurers paid $6 million. In March 2015, the class action was dismissed with prejudice and all class claims were released. As of December 31, 2014, the Company accrued a liability of $37.5 million related to this litigation, which was included in other accrued expenses in the condensed consolidated balance sheet.

Environmental. Due to the nature of the natural gas and oil industry, we are exposed to environmental risks. We have various policies and procedures to minimize and mitigate the risks from environmental contamination. We conduct periodic reviews to identify changes in our environmental risk profile. Liabilities are recorded when environmental damages resulting from past events are probable and the costs can be reasonably estimated. As of September 30, 2015 and December 31, 2014, we had accrued environmental liabilities in the amount of $4.4 million and $0.8 million, respectively, included in other accrued expenses on the condensed consolidated balance sheets. We are not aware of any environmental claims existing as of September 30, 2015 which have not been provided for or would otherwise have a material impact on our financial statements; however, there can be no assurance that current regulatory requirements will not change or that unknown past non-compliance with environmental laws will not be discovered on our properties.

In August 2015, we received a Clean Air Act Section 114 Information Request (the "Information Request") from the United States Environmental Protection Agency ("EPA"). The Information Request seeks, among other things, information related to the design, operation, and maintenance of our production facilities in the DJ Basin of Colorado. The Information Request focuses primarily on 46 of our production facilities and asks that we conduct certain sampling and analyses at the identified 46 facilities. We are currently scheduled to respond to the Information Request in January 2016. We cannot predict the outcome of this matter at this time.

In 2014, we experienced a loss of well control while drilling an oil and gas well in Morgan County, Ohio. The event resulted in a release of well fluids, including oil based drilling mud. We have completed the appropriate remediation to address the release. In August 2015, the EPA issued us a Notice of Intent seeking civil penalties. We and the EPA recently agreed in principle to settle this matter for a civil fine of approximately $152,000, although settlement is subject to the parties entering into a definitive settlement agreement.

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

NOTE 11 - COMMON STOCK

Sale of Equity Securities

In March 2015, we completed a public offering of 4,002,000 shares of our common stock, par value $0.01 per share, at a price to us of $50.73 per share. Net proceeds of the offering were $202.9 million, after deducting offering expenses and underwriting discounts, of which $40,020 is included in common shares-par value and $202.8 million is included in additional paid-in capital on the September 30, 2015 condensed consolidated balance sheet. The shares were issued pursuant to an effective shelf registration statement on Form S-3 filed with the SEC in March 2015.

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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Stock-based compensation expense	$4,813	$4,232	$14,278	$13,111
Income tax benefit	(1,828)	(1,482)	(5,423)	(4,856)
Net stock-based compensation expense	$2,985	$2,750	$8,855	$8,255

Stock Appreciation Rights ("SARs")

The SARs vest ratably over a three-year period and may be exercised at any point after vesting through ten 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 2015, the Compensation Committee awarded 68,274 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:

	Nine Months Ended September 30,	
	2015	2014
Expected term of award	6 years	6 years
Risk-free interest rate	1.6 %	2.1 %
Expected volatility	59.4 %	65.6 %
Weighted-average grant date fair value per share	$21.99	$29.96

The expected term of the award was estimated using historical stock option exercise behavior data. The risk-free interest rate was based on the U.S. Treasury yields approximating the expected life of the award in effect at the time of grant. 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 for the periods presented:

	Nine Months Ended September 30,							
	2015				2014			
	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,	279,011	$ 38.77			190,763	$ 33.77		
Awarded	68,274	39.63			88,248	49.57		
Outstanding at September 30,	347,285	38.94	7.5	$ 4,888	279,011	38.77	8.0	$ 3,215
Vested and expected to vest at September 30,	341,423	38.89	7.5	4,821	270,589	38.56	8.0	3,173
Exercisable at September 30,	191,149	35.68	6.6	3,312	109,920	32.71	7.1	1,933

Total compensation cost related to SARs granted, net of estimated forfeitures, and not yet recognized in our condensed consolidated statement of operations as of September 30, 2015 was $2.4 million. The cost is expected to be recognized over a weighted-average period of 1.7 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 anniversary following the grant date that a participant is continuously employed.

In January 2015, the Compensation Committee awarded to our executive officers a total of 80,707 time-based restricted shares that vest ratably over a three-year period ending in January 2018.

The following table presents the changes in non-vested time-based awards to all employees, including executive officers, for the nine months ended September 30, 2015:

	Shares	Weighted-Average Grant-Date Fair Value
Non-vested at December 31, 2014	564,332	$46.02
Granted	295,694	48.58
Vested	(258,555)	40.36
Forfeited	(17,457)	54.51
Non-vested at September 30, 2015	584,014	49.56

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The following table presents the weighted-average grant date fair value per share and related information as of/for the periods presented:

	As of/for the Nine Months Ended September 30,	
	2015	2014
	(in thousands, except per share data)	
Total intrinsic value of time-based awards vested	$13,061	$15,840
Total intrinsic value of time-based awards non-vested	30,959	31,996
Market price per common share as of September 30,	53.01	50.29
Weighted-average grant date fair value per share	48.58	56.64

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 September 30, 2015 was $19.2 million. This cost is expected to be recognized over a weighted-average period of 1.9 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 three 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 2015, the Compensation Committee awarded a total of 29,398 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 group of peer companies. The shares are measured over a three-year period ending on December 31, 2017 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:

	Nine Months Ended September 30,			
	2015		2014	
Expected term of award	3 years		3 years	
Risk-free interest rate	0.9	%	0.8	%
Expected volatility	53.0	%	55.2	%
Weighted-average grant date fair value per share	$57.35		$56.87	

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 the nine months ended September 30, 2015:

	Shares	Weighted-Average Grant-Date Fair Value per Share
Non-vested at December 31, 2014	83,721	$52.98
Granted	29,398	57.35
Non-vested at September 30, 2015	113,119	54.12

The following table presents the weighted-average grant date fair value per share and related information as of/for the periods presented:

	As of/for the Nine Months Ended September 30,	
	2015	2014
	(in thousands, except per share data)	
Total intrinsic value of market-based awards non-vested	$5,996	$5,746
Market price per common share as of September 30,	53.01	50.29
Weighted-average grant date fair value per share	57.35	56.87

Total compensation cost related to non-vested market-based awards, net of estimated forfeitures, and not yet recognized in our condensed consolidated statements of operations as of September 30, 2015 was $2.4 million. This cost is expected to be recognized over a weighted-average period of 1.7 years.

NOTE 12 - 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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Weighted-average common shares outstanding - basic	40,085	35,834	38,837	35,763
Dilutive effect of:				
Restricted stock	—	259	—	287
SARs	—	56	—	45
Stock options	—	1	—	1
Non-employee director deferred compensation	—	6	—	5
Convertible notes	—	672	—	730
Weighted-average common shares and equivalents outstanding - diluted	40,085	36,828	38,837	36,831

We reported a net loss for the three and nine months ended September 30, 2015. As a result, our basic and diluted weighted-average common shares outstanding were the same because 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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Weighted-average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:				
Restricted stock	816	4	836	—
SARs	83	11	87	30
Stock options	4	—	4	—
Non-employee director deferred compensation	8	—	6	—
Convertible notes	468	—	505	—
Total anti-dilutive common share equivalents	1,379	15	1,438	30

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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 diluted 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 nine months ended September 30, 2015 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 and nine months ended September 30, 2014, as the average market price during the period exceeded the conversion price.

NOTE 13 - ASSETS HELD FOR SALE, DIVESTITURES AND DISCONTINUED OPERATIONS

In October 2014, we completed the sale of our entire 50% ownership interest in PDCM to an unrelated third-party for aggregate consideration, after our share of PDCM's debt repayment and other working capital adjustments, of approximately $192 million, comprised of approximately $153 million in net cash proceeds and a promissory note due in 2020 of approximately $39 million. The transaction included the buyer's assumption of our share of the firm transportation commitment related to the assets owned by PDCM, as well as our share of PDCM's natural gas hedging positions for the years 2014 through 2017. The divestiture resulted in a pre-tax gain of $76.3 million. Proceeds from the divestiture were used to reduce outstanding borrowings on our revolving credit facility and to fund a portion of our 2014 capital budget. The divestiture represented a strategic shift that will have a major effect on our operations, in that our organizational structure no longer has joint venture partners or dry gas assets. Therefore, our proportionate share of PDCM's Marcellus Shale results of operations have been separately reported as discontinued operations in the condensed consolidated statements of operations for the three and nine months ended September 30, 2014.

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

The following table presents condensed consolidated statement of operations data related to discontinued operations:

Condensed consolidated statements of operations - discontinued operations	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014
	(in thousands)	
Revenues		
Crude oil, natural gas and NGLs sales	$5,411	$24,149
Commodity price risk management income (loss), net	1,929	(1,085)
Well operations, pipeline income and other	—	48
Total revenues	7,340	23,112
Costs, expenses and other		
Production costs	1,020	7,120
Impairment of crude oil and natural gas properties	273	433
Depreciation, depletion and amortization	1,272	9,128
Other	1,061	3,445
Gain on sale of properties and equipment	(1)	(193)
Total costs, expenses and other	3,625	19,933
Interest expense	(709)	(2,222)
Interest income	62	194
Income from discontinued operations	3,068	1,151
Provision for income taxes	(3,148)	(759)
Income (loss) from discontinued operations, net of tax	$(80)	$392

The following table presents supplemental cash flows information related to our 50% ownership interest in PDCM, which is classified as discontinued operations:

Supplemental cash flows information - discontinued operations	Nine Months Ended September 30, 2014
	(in thousands)
Cash flows from investing activities:	
Capital expenditures	$(17,253)
Significant non-cash investing items:	
Change in accounts payable related to purchases of properties and equipment	(5,727)

Assets held for sale of $2.9 million as of September 30, 2015 and December 31, 2014 represents the carrying value of approximately 12 acres of land located adjacent to our Bridgeport, West Virginia, regional headquarters.

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 and 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.

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

The following tables present our segment information:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Segment revenues:				
Oil and gas exploration and production	$228,520	$211,259	$418,356	$385,867
Gas marketing	2,580	13,297	8,336	62,649
Total revenues	$231,100	$224,556	$426,692	$448,516
Segment income (loss) before income taxes:				
Oil and gas exploration and production	$(32,046)	$136,886	$(20,309)	$174,612
Gas marketing	(201)	(51)	(539)	3
Unallocated	(30,414)	(47,362)	(91,014)	(135,472)
Income (loss) before income taxes	$(62,661)	$89,473	$(111,862)	$39,143

	September 30, 2015	December 31, 2014
	(in thousands)	
Segment assets:		
Oil and gas exploration and production	$2,261,164	$2,254,751
Gas marketing	4,266	6,979
Unallocated	76,006	75,984
Assets held for sale	2,874	2,874
Total assets	$2,344,310	$2,340,588

NOTE 15 - SUBSEQUENT EVENT

On October 26, 2015, we announced that Gysle Shellum, Chief Financial Officer, will retire effective June 30, 2016. He will remain the Chief Financial Officer until a successor is appointed and will thereafter assist with transitional and other assigned matters through his retirement date.

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PDC ENERGY, INC.

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

Production volumes from continuing operations increased substantially to 4.3 MMboe and 10.6 MMboe for the three and nine months ended September 30, 2015, respectively, representing an increase of 84% and 58%, as compared to the three and nine months ended September 30, 2014. The increase in production volumes was primarily attributable to our successful horizontal Niobrara and Codell drilling program in the Wattenberg Field and, to a lesser extent, the completion of two four-well pads in the Utica Shale in late 2014 and early 2015. Crude oil production from continuing operations increased 87% and 53% for the three and nine months ended September 30, 2015, respectively, while NGLs production from continuing operations increased 72% and 48%, respectively, compared to the same prior year periods. Crude oil production comprised approximately 46% of total production from continuing operations during both the three and nine months ended September 30, 2015. Natural gas production from continuing operations increased 86% and 69% during the three and nine months ended September 30, 2015, respectively, compared to the same prior year periods, due to our recent focus on developmental drilling in the gassier inner and middle core areas of the Wattenberg Field.

Crude oil, natural gas and NGLs sales from continuing operations, coupled with the impact of settlement of derivatives, increased during the three and nine months ended September 30, 2015. Increased production and positive net settlements on derivative positions more than offset the effect of declines in commodity prices during the quarter. Lower crude oil and natural gas index prices during the three and nine months ended September 30, 2015 were the primary reason for significant positive net settlements on derivative positions of $68.0 million and $162.5 million, respectively, compared to negative net settlements of $4.5 million and $21.5 million during the three and nine months ended September 30, 2014, respectively. Crude oil, natural gas and NGLs sales, including the impact of net settlements on derivatives, were $172.5 million and $438.0 million during the three and nine months ended September 30, 2015, respectively, compared to $116.0 million and $350.1 million during the three and nine months ended September 30, 2014, respectively. This represents increases of 49% and 25%, respectively, in the three and nine months ended September 30, 2015, compared to the same prior year periods.

Significant changes impacting our results of operations for the three months ended September 30, 2015 include the following:

- Crude oil, natural gas and NGLs sales from continuing operations decreased to $104.5 million during the three months ended September 30, 2015 compared to $120.5 million in the same prior year period, due to a 53% decrease in the weighted-average realized prices of crude oil, natural gas and NGLs, offset in part by an 84% increase in production;
- Positive net settlements on derivatives increased to $68.0 million during the three months ended September 30, 2015 compared to negative net settlements on derivatives of $4.5 million in the same prior year period, due to lower crude oil and natural gas index settlement prices;
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- Positive net change in the fair value of unsettled derivative positions during the three months ended September 30, 2015 was $55.5 million compared to a positive net change in the fair value of unsettled derivative positions of $94.7 million during the same prior year period, primarily attributable to the downward shift in the crude oil forward curve that occurred in both periods;
- General and administrative expense decreased to $18.5 million for the three months ended September 30, 2015 compared to $34.6 million in the same prior year period, primarily attributable to $16.2 million recorded during the three months ended September 30, 2014 in connection with certain partnership-related class action litigation and estimates relating to litigation arising from bankruptcy proceedings of certain affiliated partnerships;
- Impairment of crude oil and natural gas properties increased to $153.5 million for the three months ended September 30, 2015 compared to $1.9 million in the same prior year period, primarily related to the $150.3 million write-down of our Utica Shale producing and non-producing crude oil and natural gas properties to their estimated fair value; and
- Depreciation, depletion and amortization expense increased to $80.9 million during the three months ended September 30, 2015 compared to $49.6 million in the same prior year period, primarily due to increased production, offset in part by lower weighted-average depreciation, depletion and amortization rates.

Significant changes impacting our results of operations for the nine months ended September 30, 2015 include the following:

- Crude oil, natural gas and NGLs sales from continuing operations decreased to $275.5 million during the nine months ended September 30, 2015 compared to $371.6 million in the same prior year period, due to a 53% decrease in the weighted-average realized prices of crude oil, natural gas and NGLs, offset in part by a 58% increase in production;
- Positive net settlements on derivatives increased to $162.5 million during the nine months ended September 30, 2015 compared to negative net settlements on derivatives of $21.5 million in the same prior year period, due to lower crude oil and natural gas index settlement prices;
- Negative net change in the fair value of unsettled derivative positions during the nine months ended September 30, 2015 was $21.3 million compared to a positive net change in the fair value of unsettled derivative positions of $34.2 million during the

same prior year period, primarily attributable to crude oil and natural gas derivatives that settled during the nine months ended September 30, 2015;

- General and administrative expense decreased to $55.9 million for the nine months ended September 30, 2015 compared to $96.5 million in the same prior year period, primarily attributable to $40.3 million recorded during the nine months ended September 30, 2014 in connection with certain partnership-related class action litigation and estimates relating to litigation arising from bankruptcy proceedings of certain affiliated partnerships;
- Impairment of crude oil and natural gas properties increased to $158.8 million for the nine months ended September 30, 2015 compared to $3.6 million in the same prior year period, primarily related to the $150.3 million write-down of our Utica Shale producing and non-producing crude oil and natural gas properties to their estimated fair value; and
- Depreciation, depletion and amortization expense increased to $206.9 million during the nine months ended September 30, 2015 compared to $142.2 million in the same prior year period, primarily due to increased production, offset in part by lower weighted-average depreciation, depletion and amortization rates.

Due to a significant decline in commodity prices and a decrease in net-back realizations, we experienced a triggering event that required us to assess our crude oil and natural gas properties for possible impairment during the third quarter of 2015. As a result of our assessment, we recorded an impairment charge of $150.3 million to write-down our Utica Shale proved and unproved properties. Of this impairment charge, $24.7 million was recorded to write-down certain capitalized well costs on our Utica Shale proved producing properties. Additionally, as a result of the current outlook for future commodity prices, we recorded an impairment charge of $125.6 million to write-down all of our Utica Shale lease acquisition costs and pad development costs for pads not in production. We had no proved undeveloped reserves in the Utica Shale in our December 31, 2014 reserve report. Therefore, we do not believe that there will be a material change in our estimated reserve quantities at December 31, 2015 as a result of these impairments.

Despite the current commodity price environment, we have not materially altered the company-wide development plan utilized in our December 31, 2014 reserve report due to drilling efficiencies and a reduction in our well development costs. See our 2014 Form 10-K for a sensitivity analysis on how changes in commodity prices would have impacted our estimated reserves quantities at December 31, 2014. Due to these factors, we believe the projected SEC commodity prices to be used in the 2015 year-end reserve report will not cause a material reduction in the quantity of our estimated proved reserves. However, we expect these factors will cause the pre-tax present value using the projected SEC commodity prices for future net revenues (“PV-10”) to significantly decrease at December 31, 2015. The actual impact on December 31, 2015 SEC reserve quantities and their PV-10 value will depend upon the facts and circumstances at year-end.

Available liquidity as of September 30, 2015 was $392.0 million compared to $398.4 million as of December 31, 2014. Available liquidity as of September 30, 2015 is comprised of $3.7 million of cash and cash equivalents and $388.3 million available for borrowing under our revolving credit facility. These amounts exclude an additional $250 million available under our revolving credit facility, subject to certain terms and conditions of the agreement. In September 2015, we completed the semi-annual redetermination of the borrowing base under our revolving credit facility, which resulted in the reaffirmation of the borrowing base at $700 million. We have elected to maintain the aggregate commitment level at $450 million.

In March 2015, we completed a public offering of 4,002,000 shares of our common stock for net proceeds of approximately $203 million, after deducting offering expenses and underwriting discounts. We used a portion of the proceeds of the offering to repay all amounts then outstanding on our revolving credit facility, and used the remaining amounts to fund a portion of our capital program. With our current derivative position, available liquidity and expected cash flows from operations, we believe we have sufficient liquidity to allow us to execute our expected capital program through the remainder of 2015.

Operational Overview

Drilling Activities. During the nine months ended September 30, 2015, we continued to execute our strategic plan of increasing production, reserves and cash flows from drilling operations in the Wattenberg Field in Colorado and completion activities in the Utica Shale play in southeastern Ohio. In the Wattenberg Field, we are currently running five automated drilling rigs and expect to decrease our rig count to four in the fourth quarter of 2015 due to the increases in our drilling rig efficiencies. During the nine months ended September 30, 2015, we spud 130 horizontal wells and turned-in-line 93 horizontal wells in the Wattenberg Field. We also participated in 38 gross, 4.7 net, horizontal non-operated wells that were spud and 24 gross, 5.4 net, horizontal non-operated wells which were turned-in-line. We began implementing several well-recovery enhancements in 2015, including tighter spacing between frac intervals on all wells and drilling 40% of our wells with extended reach laterals of 6,500 feet to 7,000 feet. We have been able to improve our drilling time due to several factors, including the use of automated drilling rigs that minimize downtime, improved drilling team cohesion and utilizing analytics to improve drilling efficiencies. In the Utica Shale, we completed and turned-in-line a four-well pad during the first half of 2015. As a result of the four-well pads turned-in-line at the end of 2014 and the second quarter of 2015, production volumes from the Utica Shale increased 57% and 48% during the three and nine months ended September 30, 2015, respectively, compared to the same prior year periods.

2015 Operational Outlook

We expect to meet or slightly exceed the high end of our prior 2015 production guidance range of 15.0 MMBoe, while maintaining our previously provided capital guidance range of $520 million to $550 million. Through the nine months ended September 30, 2015, we have invested approximately $421 million, or 77% to 81%, of our capital forecast. Crude oil is expected to comprise 47% of our revised production and we expect a year-end exit rate exceeding 48,000 Boe per day. We expect to direct the remaining capital primarily to our drilling program in the Wattenberg Field, where we have reduced our per well development costs for both standard and extended reach laterals. Further, due to improved drilling techniques and reduced drilling time, the number of horizontal Niobrara or Codell horizontal wells expected to be spud and turned-in-line in 2015 is approximately 176 and 137, respectively. During the third quarter of 2015, our cash flows from operations approximated our cash flows from investing activities and we expect the same for the remainder of 2015.

Wattenberg Field. We expect to spud approximately 176 and turn-in-line 133 horizontal Niobrara or Codell wells in 2015, of which approximately 40% are expected to be extended reach laterals of approximately 6,500 feet to 7,000 feet. During the three months ended September 30, 2015, we spud 53 horizontal wells and turned-in-line 33 operated horizontal wells. Approximately 75% of the wells are expected to target the Niobrara formation, with the remainder targeting the Codell formation. We expect to participate in approximately 54 gross, 8.5 net, non-operated horizontal opportunities in 2015. During the nine months ended September 30, 2015, we invested approximately $395 million in the Wattenberg Field.

Utica Shale. Based upon current low commodity prices and large natural gas price differentials in Appalachia, we elected to temporarily cease drilling in the Utica Shale in early 2015 in favor of allocating more of our 2015 capital program to our higher return projects in the Wattenberg Field's inner and middle core areas. In 2015, we directed our investment in the Utica Shale to complete and turn-in-line the four-well pad that was in-process as of December 31, 2014 and for lease maintenance, exploration and other expenditures. During the nine months ended September 30, 2015, we invested approximately $23 million in the Utica Shale, the majority of which was for completion activities on the four-well pad. In the fourth quarter of 2015, we expect to make a moderate capital investment in our Washington County acreage so as to provide further support for future drilling on our southern acreage in the Utica Shale.

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PDC ENERGY, INC.

Results of Operations

Summary Operating Results

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2015	2014	Percentage Change	2015	2014	Percentage Change
	(dollars in millions, except per unit data)					
Production (1)						
Crude oil (MBbls)	2,007.8	1,072.3	87.2 %	4,895.9	3,192.3	53.4 %
Natural gas (MMcf)	9,148.9	4,910.1	86.3 %	22,997.0	13,611.1	69.0 %
NGLs (MBbls)	793.0	461.7	71.8 %	1,858.5	1,252.2	48.4 %
Crude oil equivalent (MBoe) (2)	4,325.6	2,352.3	83.9 %	10,587.3	6,713.0	57.7 %
Average MBoe per day	47.0	25.6	83.9 %	38.8	24.6	57.7 %
Crude Oil, Natural Gas and NGLs Sales						
Crude oil	$78.3	$90.8	(13.8)%	$206.7	$279.4	(26.0)%
Natural gas	18.8	17.2	9.3 %	49.4	55.0	(10.2)%
NGLs	7.4	12.5	(40.8)%	19.4	37.2	(47.8)%
Total crude oil, natural gas and NGLs sales	$104.5	$120.5	(13.3)%	$275.5	$371.6	(25.9)%
Net Settlements on Derivatives (3)						
Natural gas	$7.3	$0.3	*	$20.1	$(3.9)	*
Crude oil	60.7	(4.8)	*	142.4	(17.6)	*
Total net settlements on derivatives	$68.0	$(4.5)	*	$162.5	$(21.5)	*
Average Sales Price (excluding net settlements on derivatives)						
Crude oil (per Bbl)	$38.98	$84.67	(54.0)%	$42.22	$87.51	(51.8)%
Natural gas (per Mcf)	2.05	3.50	(41.4)%	2.15	4.04	(46.8)%
NGLs (per Bbl)	9.40	27.15	(65.4)%	10.45	29.73	(64.9)%
Crude oil equivalent (per Boe)	24.15	51.24	(52.9)%	26.02	55.35	(53.0)%
Average Lease Operating Expenses (per Boe) (4)						
Wattenberg Field	$3.00	$4.73	(36.6)%	$4.06	$4.67	(13.1)%
Utica Shale	1.17	2.68	(56.3)%	1.49	1.79	(16.8)%
Weighted-average	2.87	4.56	(37.1)%	3.85	4.42	(12.9)%
Natural Gas Marketing Contribution Margin (5)	$(0.2)	$—	*	$(0.6)	$—	*
Other Costs and Expenses						
Exploration expense	$0.3	$0.2	32.6 %	$0.8	$0.8	5.0 %
Impairment of crude oil and natural gas properties	153.5	1.9	*	158.8	3.6	*
General and administrative expense	18.5	34.6	(46.5)%	55.9	96.5	(42.1)%

Depreciation, depletion and amortization	80.9	49.6	63.1	%	206.9	142.2	45.5	%
Interest expense	$12.1	$11.8	2.3	%	$35.4	$36.2	(2.3	)%

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

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(1) Production is net and determined by multiplying the gross production volume of properties in which we have an interest by 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:

	Three Months Ended September 30,			Nine Months Ended September 30,		
Production by Operating Region	2015	2014	Percentage Change	2015	2014	Percentage Change
Crude oil (MBbls)						
Wattenberg Field	1,868.6	1,012.0	84.6 %	4,509.5	2,973.1	51.7 %
Utica Shale	139.2	60.3	130.8 %	386.4	219.2	76.3 %
Total	2,007.8	1,072.3	87.2 %	4,895.9	3,192.3	53.4 %
Natural gas (MMcf)						
Wattenberg Field	8,478.3	4,318.6	96.3 %	21,040.7	11,971.8	75.8 %
Utica Shale	670.6	591.5	13.4 %	1,956.3	1,639.3	19.3 %
Total	9,148.9	4,910.1	86.3 %	22,997.0	13,611.1	69.0 %
NGLs (MBbls)						
Wattenberg Field	730.6	421.1	73.5 %	1,692.5	1,151.3	47.0 %
Utica Shale	62.4	40.6	53.7 %	166.0	100.9	64.5 %
Total	793.0	461.7	71.8 %	1,858.5	1,252.2	48.4 %
Crude oil equivalent (MBoe)						
Wattenberg Field	4,012.3	2,152.9	86.4 %	9,708.8	6,119.7	58.6 %
Utica Shale	313.3	199.4	57.1 %	878.5	593.3	48.1 %
Total	4,325.6	2,352.3	83.9 %	10,587.3	6,713.0	57.7 %

Amounts may not recalculate due to rounding.

	Three Months Ended September 30,			Nine Months Ended September 30,		
Average Sales Price by Operating Region (excluding net settlements on derivatives)	2015	2014	Percentage Change	2015	2014	Percentage Change
Crude oil (per Bbl)						
Wattenberg Field	$38.90	$84.56	(54.0)%	$42.13	$87.41	(51.8)%
Utica Shale	40.02	86.56	(53.8)%	43.28	88.87	(51.3)%
Weighted-average price	38.98	84.67	(54.0)%	42.22	87.51	(51.8)%
Natural gas (per Mcf)						
Wattenberg Field	$2.11	$3.65	(42.2)%	$2.17	$4.10	(47.1)%
Utica Shale	1.36	2.45	(44.5)%	1.92	3.60	(46.7)%
Weighted-average price	2.05	3.50	(41.4)%	2.15	4.04	(46.8)%
NGLs (per Bbl)						
Wattenberg Field	$9.62	$25.89	(62.8)%	$10.36	$28.17	(63.2)%
Utica Shale	6.80	40.13	(83.1)%	11.40	47.58	(76.0)%
Weighted-average price	9.40	27.15	(65.4)%	10.45	29.73	(64.9)%
Crude oil equivalent (per Boe)						
Wattenberg Field	$24.32	$52.13	(53.3)%	$26.07	$55.78	(53.3)%
Utica Shale	22.04	41.58	(47.0)%	25.47	51.17	(50.2)%
Weighted-average price	24.15	51.24	(52.9)%	26.02	55.35	(53.0)%

Amounts may not recalculate due to rounding.

For the three and nine months ended September 30, 2015, crude oil, natural gas and NGLs sales revenue decreased compared to the three and nine months ended September 30, 2014 due to the following (in millions):

	September 30, 2015	
	Three Months Ended	Nine Months Ended
Decrease in average crude oil price	$(91.7)	(221.8)
Decrease in average natural gas price	(13.3)	(43.5)
Decrease in average NGLs price	(14.1)	(35.8)
Increase in production	103.1	205.0
Total decrease in crude oil, natural gas and NGLs sales revenue	$(16.0)	$(96.1)

Production from continuing operations for the third quarter of 2015 was 4.3 million Boe, up from 2.4 million Boe in the third quarter of 2014. Year-to-date, production from continuing operations was 10.6 million Boe, up from 6.7 million Boe in the first nine months of 2014. Production increased as a result of continued drilling and completion activities as discussed in Operational Overview. We continued to experience high line pressures on the midstream system in the Wattenberg Field in the first half of the year, but the Lucerne II processing plant and additional new compressor stations on the gathering system began initial operations in June 2015, resulting in immediate reductions in line pressures. We have experienced further line pressure reductions in the third quarter of 2015. Further, we expect sustained relief of gathering system pressure on our primary gatherer's system through 2016, depending upon the impact of reduced drilling activity in the field going forward. However, due to continued low commodity prices, our secondary midstream service provider, which currently gathers and processes approximately 30% of our Wattenberg Field gas, has indicated it may have limitations on its capital program in 2016, which may result in a curtailment of certain of our projected 2016 volumes. 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. The price of crude oil decreased during the third quarter of 2015 compared to the first half of 2015 amid continuing concerns regarding high U.S. inventories and slowing global demand for crude oil. Natural gas prices during the third quarter of 2015 remained at the low levels seen throughout 2015, and were at significantly lower levels than the comparable periods of 2014. NGL prices declined significantly during the first nine months of 2015 and, while they have stabilized with the prospect of cooler weather and crop drying season, also remain at low levels relative to those experienced in the comparable periods of 2014.

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, primarily 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. We began delivering crude oil in accordance with our long term commitment to the White Cliffs Pipeline, LLC ("White Cliffs") pipeline at the beginning of July 2015. This facilitates deliveries of a significant portion of our crude oil to the Cushing, Oklahoma, market. In addition, we have signed a long-term agreement for gathering of crude oil at the wellhead by pipeline from several of our pads in the Wattenberg Field, with a view toward minimizing truck traffic, increasing reliability and reducing the overall physical footprint of our well pads. We expect to deliver crude oil into this pipeline during the fourth quarter of 2015. We continue to evaluate crude oil takeaway options to determine the benefits of additional longer term commitments to deliver to competitive markets and, as a result, have entered into some three-month and six-month agreements that have resulted in significantly improved deductions compared to earlier in the year. In the Utica Shale, crude oil and condensate is sold to a local purchaser at each individual well site based on NYMEX pricing, adjusted for quality 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 and local utility prices, adjusted for certain deductions, while natural gas produced in the Utica Shale is based on TETCO M-2 pricing with a portion of our volumes currently receiving an increase in price relative to the index based upon delivery to the Chicago/Midwest market. Our sale of a significant portion of our Utica Shale gas to the Midwest market has helped to reduce the impact of the significant differentials that exist between the TETCO M-2 realizations and the NYMEX gas price. We anticipate that the significant Appalachian pipeline differentials that impact our Utica Shale natural gas will continue at least into 2016.

Our price for NGLs produced in the Wattenberg Field is based on a combination of prices from 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 to various markets. Due to an oversupply and growing inventories of nearly all domestic NGLs products, our realized sales price for NGLs declined significantly during the first three quarters of 2015 and, while these prices have stabilized, we expect pricing to remain at depressed levels well into 2016 and perhaps beyond.

Our crude oil, natural gas and NGLs sales are recorded under either the “net-back” or "gross" method of accounting, depending upon the transportation method used. We use the "net-back" method of accounting for natural gas and NGLs, as well as a portion of our crude oil production, from the Wattenberg Field and for 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. We use the "gross" method of accounting for Wattenberg Field crude oil delivered through the White Cliffs pipeline and for natural gas and NGLs sales related to production from the Utica Shale as the purchasers do not provide transportation, gathering or processing services. Under this method, we recognize revenues based on the gross selling price and recognize transportation, gathering and processing expenses as a component of production costs. As a result of the White Cliffs agreement, during the three months ended September 30, 2015, our Wattenberg Field crude oil average sales price increased approximately $1.28 per barrel attributable to recognizing these costs for transportation on the White Cliffs pipeline as an increase in transportation expense, rather than a deduction from revenues.

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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Lease operating expenses	$12.4	$10.7	$40.7	$29.7
Production taxes	5.5	8.8	13.2	22.7
Transportation, gathering and processing expenses	3.9	1.2	6.6	3.3
Overhead and other production expenses	3.7	2.1	10.6	9.0
Total production costs	$25.5	$22.8	$71.1	$64.7
Total production costs per Boe	$5.89	$9.67	$6.72	$9.62

Lease operating expenses. The $1.7 million increase in lease operating expenses during the three months ended September 30, 2015 compared to the three months ended September 30, 2014 was primarily due to an increase of $0.8 million for environmental remediation and regulatory compliance projects and $0.8 million for additional wages and employee benefits, including costs for additional contract labor. The $11.0 million increase in lease operating expenses during the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014 was primarily due to an increase of $5.4 million for environmental remediation and regulatory compliance projects, an increase of $2.7 million for additional wages and employee benefits, including costs for additional contract labor, $1.3 million for lease operating expenses incurred on the increasing number of non-operated wells in the Wattenberg Field and $0.7 million for additional costs pertaining to water hauling and disposal.

Production taxes. Production taxes are directly related to crude oil, natural gas and NGLs sales. The $3.3 million, or 38%, decrease in production taxes for the three months ended September 30, 2015 compared to the three months ended September 30, 2014, was primarily related to the 13% decrease in crude oil, natural gas and NGLs sales and lower production tax rates. Similarly, the $9.5 million, or 42%, decrease in production taxes for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014, was primarily related to the 26% decrease in crude oil, natural gas and NGLs sales and lower production tax rates.

Transportation, gathering and processing expenses. The $2.7 million and $3.3 million increases during the three and nine months ended September 30, 2015, respectively, compared to the three and nine months ended September 30, 2014 was mainly attributable to oil transportation cost on the White Cliffs pipeline as we began delivering crude oil at the beginning of July 2015. We expect to continue to incur these oil transportation costs pursuant to our long-term firm transportation agreement.

Overhead and other production expenses. The $1.6 million increase during the three months ended September 30, 2015 compared to the three months ended September 30, 2014 was mainly attributable to an increase of $0.8 million in adjustments to the value of our crude oil inventory at the lower of cost and net realizable value, the majority of which was attributable to the value of inventory for the White Cliffs pipeline line fill and an increase of $0.4 million in expired prepaid well costs. The $1.6 million increase during the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014 was mainly attributable to an increase of $1.1 million in expired prepaid well costs and an increase of $0.3 million in adjustments to value our crude oil inventory at the lower of cost and net realizable value.

Commodity Price Risk Management, Net

We use various derivative instruments to manage fluctuations in natural gas and crude oil prices. We have in place a variety of collars, fixed-price swaps and basis swaps on a portion of our estimated natural gas and crude oil production. Because we sell all of our natural gas and crude oil production 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, before contract fees, related to our collars of no less than the floor and no more than the ceiling and, for our commodity swaps, we ultimately realize the fixed price related to our swaps.

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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.

Net settlements are primarily the result of crude oil and natural gas index prices at maturity of our derivative instruments compared to the respective strike prices. Net change in fair value of unsettled derivatives is comprised of the net asset increase or decrease in the beginning-of-period fair value of derivative instruments that settled during the period and the net change in fair value of unsettled derivatives during the period. The corresponding impact of settlement of the derivative instruments that settled during the period is included in net settlements for the period as discussed above. Net change in fair value of unsettled derivatives during the period is primarily related to shifts in the crude oil and natural gas forward curves and changes in certain differentials.

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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Commodity price risk management gain, net:				
Net settlements:				
Crude oil	$60.7	$(4.8)	$142.4	$(17.6)
Natural gas	7.3	0.3	20.1	(3.9)
Total net settlements	68.0	(4.5)	162.5	(21.5)
Change in fair value of unsettled derivatives:				
Reclassification of settlements included in prior period changes in fair value of derivatives	(48.1)	12.8	(140.2)	11.2
Crude oil fixed price swaps	50.4	63.5	51.4	16.5
Crude oil collars	28.5	10.2	28.6	3.3
Natural gas fixed price swaps	19.5	6.5	31.0	2.4
Natural gas basis swaps	(1.0)	—	(2.4)	—
Natural gas collars	6.2	1.7	10.3	0.8
Net change in fair value of unsettled derivatives	55.5	94.7	(21.3)	34.2
Total commodity price risk management gain, net	$123.5	$90.2	$141.2	$12.7

Natural Gas Marketing

Fluctuations in our natural gas marketing segment'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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions)			

Natural gas sales revenue	$2.4	$12.9	$8.0	$62.9
Net settlements from derivatives	0.2	0.2	0.6	(0.4)
Net change in fair value of unsettled derivatives	—	0.2	(0.3)	0.1
Total sales from natural gas marketing	2.6	13.3	8.3	62.6
Costs of natural gas purchases	2.4	12.6	8.0	61.8
Net settlements from derivatives	0.2	0.2	0.5	(0.5)
Net change in fair value of unsettled derivatives	—	0.2	(0.3)	0.2
Other	0.2	0.3	0.7	1.1
Total costs of natural gas marketing	2.8	13.3	8.9	62.6
Natural gas marketing contribution margin	$(0.2)	$—	$(0.6)	$—

Natural gas sales revenue and cost of natural gas purchases decreased in the three and nine months ended September 30, 2015 compared to the three and nine months ended September 30, 2014, as our Gas Marketing segment has scaled down following the divestiture of our Appalachian Basin natural gas properties. Our Gas Marketing segment sold approximately 1.1 Bcf of natural gas at an average price of $1.14 per Mcf during the three months ended September 30, 2015, compared to approximately 5.0 Bcf of natural gas at an average price of $2.35 per Mcf during the three months ended September 30, 2014. Our Gas Marketing segment sold approximately 3.3 Bcf of natural gas at an average price of $1.42 per Mcf during the nine months ended September 30, 2015, compared to approximately 16.5 Bcf of natural gas at an average price of $3.62 per Mcf during the nine months ended September 30, 2014.

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.

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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Impairment of proved and unproved properties	$150.3	$—	$150.3	$—
Amortization of individually insignificant unproved properties	3.2	1.1	8.5	2.8
Other	—	0.8	—	0.8
Total impairment of crude oil and natural gas properties	$153.5	$1.9	$158.8	$3.6

Impairment of proved and unproved properties. Due to a significant decline in commodity prices and a decrease in net-back realizations, we experienced a triggering event that required us to assess our crude oil and natural gas properties for possible impairment during the third quarter of 2015. As a result of our assessment, we recorded an impairment charge of $150.3 million to write-down our Utica Shale proved and unproved properties. Of this impairment charge, $24.7 million was recorded to write-down certain capitalized well costs on our Utica Shale proved producing properties. The impairment charge represented the amount by which the carrying value of these crude oil and natural gas properties exceeded the estimated fair value. The estimated fair value of approximately $27.9 million was determined based on estimated future discounted net cash flows, a Level 3 input, using estimated production and prices at which we reasonably expect the crude oil and natural gas will be sold. Additionally, as a result of the current outlook for future commodity prices, we recorded an impairment charge of $125.6 million to write-down all of our Utica Shale lease acquisition costs and pad development costs for pads not in production. Further deterioration of commodity prices could result in additional impairment charges to our crude oil and natural gas properties.

Amortization of individually insignificant unproved properties. The period-over-period increases were primarily related to a higher number of insignificant leases that were subject to amortization, primarily in the Utica Shale where we have altered drilling plans due to lower crude oil prices and, as a result, expect certain leases to expire.

General and Administrative Expense

General and administrative expense decreased $16.1 million to $18.5 million for the three months ended September 30, 2015 compared to $34.6 million for the three months ended September 30, 2014. The decrease was primarily attributable to $16.2 million recorded during the three months ended September 30, 2014 in connection with certain partnership-related class action litigation and estimates relating to litigation arising from bankruptcy proceedings of certain affiliated partnerships.

General and administrative expense decreased $40.6 million to $55.9 million for the nine months ended September 30, 2015 compared to $96.5 million for the nine months ended September 30, 2014. The decrease was primarily attributable to $40.3 million recorded during the nine months ended September 30, 2014 in connection with certain partnership-related class action litigation and estimates relating to litigation arising from bankruptcy proceedings of certain affiliated partnerships and a $3.0 million decrease in costs for legal and other professional services during the nine months ended September 30, 2015. The decreases were offset in part by a $2.5 million increase in payroll and employee benefits during the nine months ended September 30, 2015.

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 $79.8 million and $203.5 million for the three and nine months ended September 30, 2015, respectively, compared to $48.7 million and $139.1 million for the three and nine months ended September 30, 2014. The period-over-period increases were comprised of increases of $40.8 million and $80.5 million due to higher production during the three and nine months ended September 30, 2015, respectively, offset in part by decreases of $9.7 million and $16.1 million due to lower weighted-average depreciation, depletion and amortization rates during the three and nine months ended September 30, 2015, respectively.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
Operating Region/Area	2015	2014	2015	2014
	(per Boe)			
Wattenberg Field	$19.10	$19.56	$19.92	$19.78
Utica Shale	10.08	32.98	11.49	30.75
Total weighted-average	18.44	20.70	19.22	20.73

The decrease in the Utica Shale DD&A expense rate during the three and nine months ended September 30, 2015 compared to the three and nine months ended September 30, 2014 was primarily due to the effect of an impairment recorded in December 2014 to write-down certain capitalized well costs on our Utica Shale proved producing properties, which lowered the net book value of the properties by approximately $112.6 million.

Non-crude oil and natural gas properties. Depreciation expense for non-crude oil and natural gas properties was $1.2 million and $3.4 million for the three and nine months ended September 30, 2015, respectively, compared to $1.0 million and $3.1 million for the three and nine months ended September 30, 2014, respectively.

Interest Income

Interest income increased to $1.4 million for the three months ended September 30, 2015, mainly attributable to $1.1 million of non-cash interest income recognized during the three months ended September 30, 2015 on a promissory note received as part of the consideration for the sale of our entire 50% ownership interest in PDCM, of which $0.8 million was paid-in-kind and added to the principal amount of the promissory note.

Interest income increased to $3.6 million for the nine months ended September 30, 2015 compared to $0.3 million for the nine months ended September 30, 2014, mainly attributable to $3.4 million of non-cash interest income recognized during the nine months ended September 30, 2015 on the above-mentioned promissory note, of which $2.4 million was paid-in-kind and added to the principal amount of the promissory note.

Interest Expense

Interest expense increased $0.3 million to $12.1 million for the three months ended September 30, 2015 compared to $11.8 million for the three months ended September 30, 2014. The increase is primarily comprised of a $0.2 million increase due to higher average borrowings on our revolving credit facility during the three months ended September 30, 2015.

Interest expense decreased $0.8 million to $35.4 million for the nine months ended September 30, 2015 compared to $36.2 million for the nine months ended September 30, 2014. The decrease is primarily comprised of a $2.0 million decrease attributable to an increase in capitalized interest, offset in part by a $0.9 million increase due to higher average borrowings on our revolving credit facility during the nine months ended September 30, 2015.

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 nine months ended September 30, 2015 compared to the three and nine months ended September 30, 2014. The effective tax rate of 33.8% and 36.3% benefit on loss from continuing operations for the three and nine months ended September 30, 2015, respectively, are based on forecasted pre-tax loss for the year adjusted for permanent differences. The forecasted full year 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 or loss 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 October 2014, we completed the sale of our entire 50% ownership interest in PDCM to an unrelated third-party for aggregate consideration, after our share of PDCM's debt repayment and other working capital adjustments, of approximately $192 million, comprised of approximately $153 million in net cash proceeds and a promissory note due in 2020 of approximately $39 million. The transaction included the buyer's assumption of our share of the firm transportation commitment related to the assets owned by PDCM, as well as our share of PDCM's natural gas hedging positions for the years 2014 through 2017. The divestiture resulted in a pre-tax gain of $76.3 million. The divestiture represented a strategic shift in our operations. Accordingly, our proportionate share of PDCM's Marcellus Shale results of operations have been separately reported as discontinued operations in the condensed consolidated statement of operations for the three and nine months ended September 30, 2014.

See Note 13, 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 ownership interest in PDCM.

The table below presents production data related to PDCM's Marcellus Shale assets that have been divested and that are classified as discontinued operations:

	September 30, 2014	
Discontinued Operations	Three Months Ended	Nine Months Ended
Production		
Natural gas (MMcf)	2,097.4	6,557.9
Crude oil equivalent (MBoe)	349.6	1,093.0

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

Net loss for the three and nine months ended September 30, 2015 was $41.5 million and $71.3 million compared to net income of $54.0 million and $23.7 million for the three and nine months ended September 30, 2014. Adjusted net loss, a non-U.S. GAAP financial measure, was $75.9 million for the three months ended September 30, 2015 compared to adjusted net loss of $5.7 million for the same prior year period. Adjusted net loss was $58.1 million for the nine months ended September 30, 2015 compared to adjusted net income of $2.4 million for the same prior year period. The quarter-over-quarter and year-over-year changes in net income are discussed above, with the most significant changes related to the increases in impairment of crude oil and natural gas properties, DD&A expense and commodity price risk management activity income and the decrease in crude oil, natural gas and NGLs sales and general and administrative expense. 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 and asset sales. For the nine months ended September 30, 2015, our primary sources of liquidity were net cash flows from operating activities of $283.0 million and the proceeds received from the March 2015 public offering of our common stock of approximately $203 million. We used a portion of the proceeds of the offering to repay all amounts then outstanding on our revolving credit facility and used the remaining amounts to fund a portion of our capital program.

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 for such related time period (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 us from entering into hedges that would exceed 85% of our expected future production from proved developed producing properties during that time period. In addition, we may choose not to hedge the maximum amounts permitted under our covenants. 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. Given current commodity prices and our hedge position, we expect that positive net settlements on our derivative positions will continue to be a significant positive component of our 2015 cash flows from operations.

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 September 30, 2015, we had a working capital deficit of $9.5 million compared to a surplus of $30.3 million at December 31, 2014. The decrease in working capital to a deficit as of September 30, 2015 is primarily the result of classifying as a current liability the carrying value of the Convertible Notes, net of discount, as the stated maturity of the Convertible Notes is May 2016.

We ended September 2015 with cash and cash equivalents of $3.7 million and availability under our revolving credit facility of $388.3 million, for a total liquidity position of $392.0 million, compared to $398.4 million at December 31, 2014. These amounts exclude an additional $250 million available under our revolving credit facility, subject to certain terms and conditions of the agreement. The decrease in liquidity of $6.4 million, or 1.6%, was primarily attributable to capital expenditures of $489.0 million during the nine months ended September 30, 2015, which was financed by approximately $203 million received from the public offering of our common stock and cash flows provided by operating activities of $283.0 million. Our revised forecast estimates our adjusted cash flows from operations will range from $400 million to $420 million in 2015, based on estimated NYMEX crude oil and natural gas prices, before the effects of differentials or hedges, of $48.98 per barrel of crude oil, $2.87 per Mcf of natural gas and $9.61 per barrel of NGLs. Due to the derivative hedges in place as of September 30, 2015, a $10 per barrel change in the price of crude oil would change our estimated adjusted cash flows from operations for the remainder of 2015 by approximately $4 million to $8 million. Based on our current commodity mix and hedge position, we estimate that a decline in the price of natural gas will not have a material impact on our adjusted cash flows from operations in 2015. With our current derivative position, liquidity position and expected cash flows from operations, we believe that we have sufficient capital to fund our development plan.

In March 2015, 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 approximately four million shares of our common stock in March 2015 in an underwritten public offering at a price to us of approximately $50.73 per share.

In recent periods, including the nine months ended September 30, 2015, we have been able to access borrowings under our revolving credit facility and to obtain proceeds from the issuance of securities. We cannot, however, assure this will continue to be the case in the future. In light of recent weakened commodity prices, we continue to monitor market conditions and their potential impact on each of our revolving credit facility lenders, many of which are counterparties in our derivative transactions. Our 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. In September 2015, we completed the semi-annual redetermination of our revolving credit facility, which resulted in the reaffirmation of our borrowing base at $700 million. Further, we entered into a Second Amendment to Third Amended and Restated Credit Agreement that extended the maturity date of our revolving credit facility to May 2020. However, we have elected to maintain the aggregate commitment at $450 million. We had $50.0 million outstanding on our revolving credit facility as of September 30, 2015. While we have added and expect to continue to add producing reserves through our drilling operations, the effect of any such reserve additions on our borrowing base could be offset by other factors including, among other things, a prolonged period of depressed commodity prices or regulatory pressure on lenders to reduce their exposure to exploration and production companies.

Our revolving credit facility contains financial maintenance covenants. The covenants require that we maintain: (i) total debt of less than 4.25 times the trailing 12 months 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 September 30, 2015, we were in compliance with all debt covenants with a 1.6 times debt to EBITDAX ratio and a 1.5 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 September 30, 2015, we were in compliance with all covenants and expect to remain in compliance throughout the next year.

The conversion rights on our Convertible Notes could be triggered prior to the maturity date. We have currently 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. The Convertible Notes were not convertible at the option of holders as of the date of this filing.

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 $81.0 million for the nine months ended September 30, 2015, compared to the nine months ended September 30, 2014. The increase in cash provided by operating activities was primarily due to the increase in net settlements from our derivative positions of $183.9 million and a decrease in general and administrative expense of $40.7 million. The increase was partially offset by the decrease in crude oil, natural gas and NGLs sales of $96.1 million, changes in assets and liabilities of $32.3 million related to the timing of cash payments and receipts and a $9.6 million decrease in cash flows from discontinued operating activities. 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 $113.4 million during the nine months ended September 30, 2015, compared to the nine months ended September 30, 2014. 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 $109.8 million during the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014. The increase was primarily the result of the increase in net settlements from our derivative positions of $183.9 million and a decrease in general and administrative expense of $40.7 million. The increase was partially offset by the decrease in crude oil, natural gas and NGLs sales of $96.1 million, a $12.6 million decrease in contribution margins from discontinued operations and a $6.5 million increase in production costs. 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 for a prolonged period 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 the acquisition, exploration and development of crude oil and natural gas properties, net of dispositions of crude oil and natural gas properties. During the nine months ended September 30, 2015, our drilling program consisted of five drilling rigs operating in the horizontal Niobrara and Codell plays in our Wattenberg Field. Net cash used in investing activities of $488.7 million during the nine months ended September 30, 2015 was primarily related to cash utilized for our drilling operations. During the third quarter of 2015, our cash flows from operations approximated our cash flows from investing activities and we expect the same for the remainder of 2015.

Financing Activities. Net cash from financing activities for the nine months ended September 30, 2015 increased by approximately $120.3 million compared to the nine months ended September 30, 2014. Net cash from financing activities of $193.3 million for the nine months ended September 30, 2015 was primarily related to the $202.9 million received from the issuance of our common stock in March 2015, partially offset by net payments of approximately $6.0 million to pay down amounts borrowed under our revolving credit facility.

Drilling Activity

The following table presents our net developmental drilling activity for the periods shown. Productive wells consist of wells spud, turned-in-line and producing during the period. In-process wells represent wells that have been spud, drilled or are waiting to be completed and/or for gas pipeline connection during the period.

	Net Drilling Activity										
	Three Months Ended September 30,					Nine Months Ended September 30,					
	2015			2014		2015			2014		
Operating Region/Area	Productive	In-Process	Dry (1)	Productive	In-Process	Productive	In-Process	Dry (1)	Productive	In-Process	Dry (1)
Development Wells											
Wattenberg Field	27.7	57.7	1.1	12.1	48.9	80.4	57.7	2.1	48.3	48.9	1.7
Utica Shale	—	—	—	2.0	3.7	3.0	—	—	4.0	3.7	1.0
Marcellus Shale (2)	—	—	—	—	—	—	—	—	2.0	—	—
Total drilling activity	27.7	57.7	1.1	14.1	52.6	83.4	57.7	2.1	54.3	52.6	2.7

(1) Represents mechanical failures that resulted in the plugging and abandonment of the respective wells.
(2) Represents PDCM's drilling activity. On October 14, 2014, we closed the sale of our entire 50% ownership interest in PDCM to an unrelated third-party. See Note 13, Assets Held for Sale, Divestitures and Discontinued Operations to our condensed consolidated financial statements included elsewhere in this report for additional information.

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Off-Balance Sheet Arrangements

At September 30, 2015, 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 10, 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 2014 Form 10-K filed with the SEC on February 19, 2015.

Reconciliation of 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.

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 operating 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.

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PDC ENERGY, INC.

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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Adjusted cash flows from operations:				
Adjusted cash flows from operations	$122.7	$55.5	$293.6	$180.2
Changes in assets and liabilities	13.8	14.9	(10.6)	21.8
Net cash from operating activities	$136.5	$70.4	$283.0	$202.0
Adjusted net income (loss):				
Adjusted net income (loss)	$(75.9)	$(5.7)	$(58.1)	$2.4
Gain on commodity derivative instruments	123.5	92.2	141.2	11.6
Net settlements on commodity derivative instruments	(68.0)	4.1	(162.5)	22.7
Tax effect of above adjustments	(21.1)	(36.6)	8.1	(13.0)
Net income (loss)	$(41.5)	$54.0	$(71.3)	$23.7
Adjusted EBITDA to net income (loss):				
Adjusted EBITDA	$128.6	$62.6	$311.6	$201.8
Gain on commodity derivative instruments	123.5	92.2	141.2	11.6
Net settlements on commodity derivative instruments	(68.0)	4.1	(162.5)	22.7
Interest expense, net	(10.7)	(12.4)	(31.8)	(37.9)
Income tax provision	21.2	(38.5)	40.6	(16.6)
Impairment of crude oil and natural gas properties	(153.5)	(2.2)	(158.8)	(4.0)
Depreciation, depletion and amortization	(81.0)	(50.9)	(206.9)	(151.3)
Accretion of asset retirement obligations	(1.6)	(0.9)	(4.7)	(2.6)
Net income (loss)	$(41.5)	$54.0	$(71.3)	$23.7
Adjusted EBITDA to net cash from operating activities:				
Adjusted EBITDA	$128.6	$62.6	$311.6	$201.8
Interest expense, net	(10.7)	(12.4)	(31.8)	(37.9)
Stock-based compensation	4.8	4.2	14.3	13.1
Amortization of debt discount and issuance costs	1.8	1.8	5.3	5.2
(Gain) loss on sale of properties and equipment	(0.1)	—	(0.3)	0.4
Other	(1.7)	(0.7)	(5.5)	(2.4)
Changes in assets and liabilities	13.8	14.9	(10.6)	21.8
Net cash from operating activities	$136.5	$70.4	$283.0	$202.0

Amounts above include results from continuing and discontinued operations.

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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 September 30, 2015, 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 September 30, 2015 was $0.7 million with an average interest rate of 0.1%. Based on a sensitivity analysis of our interest bearing deposits as of September 30, 2015, it was estimated that if market interest rates would have increased 1%, the impact on interest income for the nine months ended September 30, 2015 would have been insignificant.

As of September 30, 2015, excluding the $11.7 million irrevocable standby letter of credit, we had a $50.0 million outstanding balance on our revolving credit facility. It was estimated that if market interest rates would have increased or decreased 1%, our interest expense for the nine months ended September 30, 2015 would have changed by approximately $0.4 million.

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 September 30, 2015:

	Collars			Fixed-Price Swaps		Basis Protection Swaps		
Commodity/ Index/ Maturity Period	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted-Average Contract Price Floors	Weighted-Average Contract Price Ceilings	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted-Average Contract Price	Quantity (BBtu) (1)	Weighted-Average Contract Price	Fair Value September 30, 2015 (2) (in millions)
Natural Gas								
NYMEX								
2015	2,830.0	$ 3.92	$ 4.30	2,970.0	$ 3.98	4,800.0	$ (0.29)	$ 7.1
2016	7,820.0	3.88	4.24	21,930.0	3.93	22,800.0	(0.30)	31.5

2017	7,920.0	3.59	4.13	23,090.0	3.67	9,600.0	(0.29)	20.7
2018	1,230.0	3.00	3.67	4,830.0	3.37	—	—	1.7
CIG								
2015	—	—	—	556.0	4.02	—	—	0.9
Total Natural Gas	19,800.0			53,376.0		37,200.0		61.9
Crude Oil								
NYMEX								
2015	234.0	86.79	96.63	1,187.0	89.42	—	—	61.1
2016	1,740.0	77.59	97.55	2,400.0	90.37	—	—	147.4
2017	960.0	54.06	73.77	180.0	61.15	—	—	7.8
Total Crude Oil	2,934.0			3,767.0		—		216.3
Total Natural Gas and Crude Oil								$278.2

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

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

	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2015	Year Ended December 31, 2014
Average Index Closing Price:			
Crude oil (per Bbl)			
NYMEX	$46.43	$51.00	$92.91
Natural gas (per MMBtu)			
NYMEX	$2.77	$2.80	$4.42
CIG	2.52	2.54	4.17
TETCO M-2 (1)	1.21	1.55	3.35
Average Sales Price Realized:			
Excluding net settlements on derivatives			
Crude oil (per Bbl)	$38.98	$42.22	$80.67
Natural gas (per Mcf)	2.05	2.15	3.87
NGLs (per Bbl)	9.40	10.45	27.39

(1) TETCO M-2 is an index price upon which a majority of our natural gas produced in the Utica Shale is sold.

Based on a sensitivity analysis as of September 30, 2015, 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 $49.4 million, whereas a 10% decrease in prices would have resulted in an increase in fair value of $50.0 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. We monitor the creditworthiness of significant 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 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. As commodity prices continue to remain depressed, certain customers under our Gas Marketing segment have begun and will continue to experience financial distress, which has led to certain contractual defaults. To date, we have had no material counterparty default losses relating to customers in either segment.

We primarily use financial institutions which are lenders in our revolving credit facility as counterparties for our derivative financial instruments. Disruption in the credit markets, changes in commodity prices and other factors 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 condensed 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 September 30, 2015, it does not consider those exposures or positions which could arise after that date. As a result, our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, our commodity price risk management strategies at the time, and interest rates and commodity prices at the time.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of September 30, 2015, 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 September 30, 2015.

Changes in Internal Control over Financial Reporting

During the three months ended September 30, 2015, 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 10, Commitments and Contingencies – Litigation, to our condensed consolidated financial statements included elsewhere in this report.

ITEM 1A. RISK FACTORS

We face many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock are described under Item 1A, Risk Factors, of our 2014 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
July 1 - 31, 2015	15,237	$51.36
August 1 - 31, 2015	330	46.95
September 1 - 30, 2015	—	—
Total third quarter purchases	15,567	51.27

(1) Purchases 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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ITEM 6. EXHIBITS

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
10.1	Second Amendment to Third Amended and Restated Credit Agreement dated as of September 30, 2015, among PDC Energy, Inc. as the Borrower, the Lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent for the Lenders.	8-K	001-37419	10.1	10/2/2015	
10.2*	Retirement Agreement with Gysle R. Shellum, Chief Financial Officer, dated October, 26, 2015.	8-K	000-07246	10.1	10/27/2015	
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.					
99.1	Certificate of Conversion, effective June 5, 2015.	8-K12B	000-07246	99.1	6/8/2015	
99.2	Articles of Conversion, effective June 5, 2015.	8-K12B	000-07246	99.2	6/8/2015	
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