PDC ENERGY, INC.
Form 10-Q
August 09, 2016
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2016

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 x No o

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 x No o

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 o (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 o No x

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 47,154,493 shares of the Company's Common Stock ($0.01 par value) were outstanding as of July 18, 2016.

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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: the closing of pending transactions and the effects of such transactions, including the fact that the transactions contemplated by the Noble exchange agreements are subject to continuing diligence between the parties and accordingly, may not occur within the expected timeframe or at all; estimated future production (including the components of such production), sales, expenses, cash flows, liquidity and balance sheet attributes; estimated crude oil, natural gas and natural gas liquids (“NGLs”) reserves; the impact of prolonged depressed commodity prices, including potentially reduced production and associated cash flow; anticipated capital projects, expenditures and opportunities, including our expectation that 2016 cash flows from operations will approximate cash flows from investing activities; expected capital budget allocations; our operational flexibility and ability to revise our development plan, either upward or downward; availability of sufficient funding and liquidity for our capital program and sources of that funding; expected positive net settlements on derivatives in the second half of 2016; that we expect quarter-over-quarter production growth; future exploration, drilling and development activities, including non-operated activity, the number of drilling rigs we expect to run and lateral lengths of wells; expected 2016 production and cash flow ranges and timing of turn-in-lines; our evaluation method of our customers' and derivative counterparties' credit risk; effectiveness of our derivative program in providing a degree of price stability; potential for future impairments; expected sustained relief of gathering system pressure; compliance with debt and senior notes covenants; impact of litigation on our results of operations and financial position; that we do not expect to pay dividends in the foreseeable future; our belief that certain proposed initiatives in Colorado may not qualify to be included on the ballot in 2016; 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 materials, we may use the terms “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. Because such statements relate to events or conditions further in the future, they are subject to increased levels of uncertainty.

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;
- reductions in the borrowing base under our revolving credit facility;
- 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;

- declines in the value of our crude oil, natural gas and NGLs properties resulting in further 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;
- 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;
- 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, 2015 (the "2015 Form 10-K"), filed with the U.S. Securities and Exchange Commission ("SEC") on February 22, 2016, and our other filings with the SEC

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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. See Note 1, Nature of Operations and Basis of Presentation, to our condensed consolidated financial statements included elsewhere in this report for a description of our consolidated subsidiaries.

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PART I - FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

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

	June 30, 2016	December 31, 2015
Assets		
Current assets:		
Cash and cash equivalents	$109,099	$850
Accounts receivable, net	107,350	104,274
Fair value of derivatives	98,839	221,659
Prepaid expenses and other current assets	3,847	5,266
Total current assets	319,135	332,049
Properties and equipment, net	1,930,595	1,940,552
Fair value of derivatives	12,745	44,387
Other assets	9,195	53,555
Total Assets	$2,271,670	$2,370,543
Liabilities and Shareholders' Equity		
Liabilities		
Current liabilities:		
Accounts payable	$64,234	$92,613
Production tax liability	19,261	26,524
Fair value of derivatives	22,824	1,595
Funds held for distribution	49,965	29,894
Current portion of long-term debt	—	112,940
Accrued interest payable	8,557	9,057
Other accrued expenses	22,358	28,709
Total current liabilities	187,199	301,332
Long-term debt	492,997	529,437
Deferred income taxes	41,133	143,452
Asset retirement obligation	81,583	84,032
Fair value of derivatives	26,830	695
Other liabilities	17,363	24,398
Total liabilities	847,105	1,083,346
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, 47,162,446 and 40,174,776 issued as of June 30, 2016 and December 31, 2015, respectively	472	402
Additional paid-in capital	1,211,876	907,382
Retained earnings	213,442	380,422
Treasury shares - at cost, 23,822 and 20,220 as of June 30, 2016 and December 31, 2015, respectively	(1,225)	(1,009)

Total shareholders' equity	1,424,565	1,287,197
Total Liabilities and Shareholders' Equity	$2,271,670	$2,370,543

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

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Revenues				
Crude oil, natural gas and NGLs sales	$110,841	$96,928	$186,208	$171,037
Sales from natural gas marketing	1,879	2,523	4,050	5,756
Commodity price risk management gain (loss), net	(92,801)	(49,041)	(81,745)	17,621
Well operations, pipeline income and other	178	550	2,415	1,178
Total revenues	20,097	50,960	110,928	195,592
Costs, expenses and other				
Lease operating expenses	13,675	12,639	29,005	28,924
Production taxes	6,043	3,837	10,114	7,730
Transportation, gathering and processing expenses	4,465	1,308	8,506	2,646
Cost of natural gas marketing	2,125	2,836	4,703	6,094
Exploration expense	237	275	447	560
Impairment of properties and equipment	4,170	4,404	5,171	7,176
General and administrative expense	23,579	20,728	46,358	41,773
Depreciation, depletion and amortization	107,014	70,106	204,402	125,926
Provision for uncollectible notes receivable	—	—	44,738	—
Accretion of asset retirement obligations	1,811	1,588	3,623	3,148
(Gain) loss on sale of properties and equipment	260	(207)	176	(228)
Total cost, expenses and other	163,379	117,514	357,243	223,749
Loss from operations	(143,282)	(66,554)	(246,315)	(28,157)
Interest expense	(10,672)	(11,567)	(22,566)	(23,292)
Interest income	177	1,135	1,735	2,248
Loss before income taxes	(153,777)	(76,986)	(267,146)	(49,201)
Provision for income taxes	58,327	30,116	100,166	19,393
Net loss	$(95,450)	$(46,870)	$(166,980)	$(29,808)
Earnings per share:				
Basic	$(2.04)	$(1.17)	$(3.78)	$(0.78)
Diluted	$(2.04)	$(1.17)	$(3.78)	$(0.78)
Weighted-average common shares outstanding:				
Basic	46,742	40,035	44,175	38,202
Diluted	46,742	40,035	44,175	38,202

See accompanying Notes to Condensed Consolidated Financial Statements

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

	Six Months Ended June 30,	
	2016	2015
Cash flows from operating activities:		
Net loss	$(166,980)	$(29,808)
Adjustments to net loss to reconcile to net cash from operating activities:		
Net change in fair value of unsettled derivatives	201,825	76,869
Depreciation, depletion and amortization	204,402	125,926
Provision for uncollectible notes receivable	44,738	—
Impairment of properties and equipment	5,171	7,176
Accretion of asset retirement obligation	3,623	3,148
Stock-based compensation	11,126	9,465
(Gain) loss on sale of properties and equipment	176	(228)
Amortization of debt discount and issuance costs	3,077	3,521
Deferred income taxes	(102,319)	(22,630)
Non-cash interest income	(1,194)	(2,247)
Other	(93)	(402)
Changes in assets and liabilities	(5,754)	(24,333)
Net cash from operating activities	197,798	146,457
Cash flows from investing activities:		
Capital expenditures	(235,707)	(358,135)
Proceeds from sale of properties and equipment	4,903	243
Net cash from investing activities	(230,804)	(357,892)
Cash flows from financing activities:		
Proceeds from sale of equity, net of issuance cost	296,575	202,851
Proceeds from revolving credit facility	85,000	272,000
Repayment of revolving credit facility	(122,000)	(275,000)
Redemption of convertible notes	(115,000)	—
Other	(3,320)	(3,106)
Net cash from financing activities	141,255	196,745
Net change in cash and cash equivalents	108,249	(14,690)
Cash and cash equivalents, beginning of period	850	16,066
Cash and cash equivalents, end of period	$109,099	$1,376
Supplemental cash flow information:		
Cash payments for:		
Interest, net of capitalized interest	$22,462	$22,828
Income taxes	167	9,936
Non-cash investing and financing activities:		
Change in accounts payable related to purchases of properties and equipment	$(28,999)	$(41,490)
Change in asset retirement obligation, with a corresponding change to crude oil and natural gas properties, net of disposals	843	1,395
Purchase of properties and equipment under capital leases	1,074	950

See accompanying Notes to Condensed Consolidated Financial Statements

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PDC ENERGY, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2016
(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 June 30, 2016, we owned an interest in approximately 3,000 gross wells. We are engaged in two business segments: Oil and Gas Exploration and Production and Gas Marketing.

The accompanying unaudited condensed consolidated financial statements include the accounts of PDC, our wholly-owned subsidiary Riley Natural Gas ("RNG") and our proportionate share of our four affiliated partnerships. Pursuant to the proportionate consolidation method, our accompanying condensed consolidated financial statements include our pro rata share of assets, liabilities, revenues and expenses of the entities which we proportionately consolidate. All material intercompany accounts and transactions have been eliminated in consolidation.

In our opinion, the accompanying condensed consolidated financial statements contain all adjustments (consisting of only normal recurring adjustments) necessary for a fair statement of our financial statements for interim periods in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the SEC. Accordingly, pursuant to such rules and regulations, certain notes and other financial information included in audited financial statements have been condensed or omitted. The December 31, 2015 condensed consolidated balance sheet data was derived from audited statements, but does not include disclosures required by U.S. GAAP. 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 2015 Form 10-K. Our results of operations and cash flows for the three and six months ended June 30, 2016 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 March 2016, the FASB issued an update to the standard intended to improve the operability and understandability of the implementation guidance on principal versus agent considerations when recognizing revenue. The revenue standard is effective for 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 requires management to assess an entity's ability to continue as a going concern at the end of 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. We expect to adopt this standard in the fourth quarter of 2016. Adoption of this standard is not expected to have a significant impact on our condensed consolidated financial statements.

In February 2016, the FASB issued an accounting update aimed at increasing the transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet and disclosing key information about related leasing arrangements. For leases with terms of more than 12 months, the accounting update requires lessees to recognize an asset for its right to use the underlying asset and a lease liability for the corresponding lease obligation. Both the lease asset and liability will initially be measured at the present value of the future minimum lease payments over the lease term. Subsequent measurement, including the presentation of expenses and cash flows, will depend upon the classification of the lease as either a finance or operating lease. The guidance is effective for fiscal years beginning after December 15, 2018, and interim periods within those years, with early adoption permitted, and is to be applied as of the beginning of the earliest period presented using a modified retrospective approach. We are currently evaluating the impact these changes may have on our condensed consolidated financial statements.

In March 2016, the FASB issued an accounting update on stock-based compensation intended to simplify several aspects of the accounting for employee share-based payment award transactions. Areas of simplification include income tax consequences, classification of the awards as either equity or liabilities and the classification on the statement of cash flows. The guidance is effective for fiscal years beginning after December 15, 2016, and interim periods within those years, with early adoption permitted. We expect to adopt this standard in the fourth quarter of 2016. Adoption of this standard is not expected to have a significant impact on our condensed consolidated financial statements.

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NOTE 3 - FAIR VALUE OF 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 upon a pricing model that utilizes market-based inputs, including, but not limited to, the contractual price of the underlying position, current market prices, crude oil and natural gas forward curves, discount rates such as the LIBOR curve for a similar duration of each outstanding position, volatility factors and nonperformance risk. Nonperformance risk considers the effect of our credit standing on the fair value of derivative liabilities and the effect of our counterparties' credit standings on the fair value of derivative assets. Both inputs to the model are based on published credit default swap rates and the duration of each outstanding derivative position.

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

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

	June 30, 2016			December 31, 2015		
	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	$74,823	$ 36,761	$111,584	$174,657	$ 91,288	$265,945
Basis protection derivative contracts	—	—	—	101	—	101
Total assets	74,823	36,761	111,584	174,758	91,288	266,046
Liabilities:						
Commodity-based derivative contracts	38,518	9,476	47,994	738	—	738
Basis protection derivative contracts	1,660	—	1,660	1,552	—	1,552
Total liabilities	40,178	9,476	49,654	2,290	—	2,290
Net asset	$34,645	$ 27,285	$61,930	$172,468	$ 91,288	$263,756

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)			
Fair value, net asset beginning of period	$73,105	$74,817	$91,288	$62,356
Changes in fair value included in statement of operations line item:				
Commodity price risk management gain (loss), net	(26,422)	(10,749)	(20,257)	4,440
Sales from natural gas marketing	—	(1)	(20)	—
Settlements included in statement of operations line items:				
Commodity price risk management gain (loss), net	(19,398)	(5,809)	(43,656)	(8,534)
Sales from natural gas marketing	—	(3)	(70)	(7)
Fair value, net asset end of period	$27,285	$58,255	$27,285	$58,255
Net change in fair value of unsettled derivatives included in statement of operations line item:				
Commodity price risk management gain (loss), net	$(18,210)	$(10,056)	$(13,105)	$3,629

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 during the periods covered by this report.

Non-Derivative Financial Assets and Liabilities

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

We utilize fair value on a nonrecurring basis to review our crude oil and natural gas properties for possible impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such properties. The fair value of the properties is determined based upon estimated future discounted cash flow, a Level 3 input, using estimated production and prices at which we reasonably expect the crude oil and natural gas will be sold.

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 June 30, 2016 and December 31, 2015.

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 June 30, 2016, we estimate the fair value of the portion of our long-term debt related to our 7.75% senior notes due 2022 to be $521.3 million, or 104.3% 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 due to the variable nature of the imputed interest rates and the duration of the related vehicle lease.

Concentration of Risk

Derivative Counterparties. Our derivative arrangements expose us to credit risk of nonperformance by our counterparties. We primarily use financial institutions who are also lenders under our revolving credit facility as counterparties to our derivative contracts. To date, we have had no counterparty default losses relating to our derivative arrangements. We have evaluated the credit risk of our derivative assets from our counterparties using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the potential impact of nonperformance of our counterparties on the fair value of our derivative instruments was not significant at June 30, 2016, taking into account the estimated likelihood of nonperformance.

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

The following table presents the counterparties that expose us to credit risk as of June 30, 2016 with regard to our derivative assets:

Counterparty Name	Fair Value of Derivative Assets (in thousands)
Canadian Imperial Bank of Commerce (1)	$ 33,559
JP Morgan Chase Bank, N.A (1)	29,011
Bank of Nova Scotia (1)	22,676
Wells Fargo Bank, N.A. (1)	13,351
NATIXIS (1)	10,418
Other lenders in our revolving credit facility	2,329
Various (2)	240
Total	$ 111,584

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

Notes Receivable. The following table presents information regarding a note receivable outstanding as of June 30, 2016:

	Amount (in thousands)	
Note receivable:		
Principal outstanding, December 31, 2015	$ 43,069	
Paid-in-kind interest	969	
Principal outstanding, June 30, 2016	44,038	
Allowance for uncollectible notes receivable	(44,038	)
Note receivable, net	$ —	

In October 2014, we sold our entire 50% ownership interest in PDCM to an unrelated third-party. 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 is payable 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 June 30, 2016, the issuer of the Note had elected the PIK Interest option. The principal and any unpaid interest is due and payable in full in September 2020 and can be prepaid in whole or in part at any time without premium or penalty. If an event of default occurs under the Note agreement, the Note must be repaid prior to maturity. The Note is secured by a pledge of stock in certain subsidiaries of the unrelated third-party, debt securities and other assets.

On a quarterly basis, we examine the Note for evidence of impairment, evaluating factors such as the creditworthiness of the issuer of the Note and the value of the underlying assets that secure the Note. We performed our quarterly evaluation and cash flow analysis as of March 31, 2016 and, based upon the unaudited year-end financial statements and reserve report of the issuer of the Note received by us in late March 2016 and existing market conditions, determined that collection of the Note and PIK Interest was not reasonably assured. As a result, we recognized a provision and recorded an allowance for uncollectible notes receivable for the $44.0 million outstanding balance as of March 31, 2016, which was included in the condensed consolidated balance sheet line item other assets.

Under the effective interest method, we recognized $1.2 million of interest income related to the Note for the three months ended March 31, 2016, of which $1.0 million was PIK Interest, and we recognized $1.1 million and $2.2 million of interest income related to the Note for the three and six months ended June 30, 2015, respectively, of which $0.8 million and $1.6 million, respectively, was PIK Interest.

Additionally, we recorded a $0.7 million provision and allowance for uncollectible notes receivable to impair a promissory note related to a previous divestiture as collection of the promissory note is not reasonably assured based on the analysis we performed as of March 31, 2016.

As of June 30, 2016, there has been no change to our assessment of the collectibility of the notes or related interest since March 31, 2016.
Commencing in the second quarter of 2016, we have ceased recognizing interest income on the notes and are accounting for the notes under the cash basis method.

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NOTE 4 - DERIVATIVE FINANCIAL INSTRUMENTS

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

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

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

We believe our derivative instruments continue to be effective in achieving the risk management objectives for which they were intended. As of June 30, 2016, 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 71,560 BBtu of natural gas and 9,214 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 not elected to designate any of our derivative instruments as hedges, and therefore do not qualify for use of hedge accounting. Accordingly, changes in the fair value of our derivative instruments are recorded in the statements of operations. Changes in the fair value of derivative instruments related to our Oil and Gas Exploration and Production segment are recorded in commodity price risk management, net. Changes in the fair value of derivative instruments related to our Gas Marketing segment are recorded in sales from and cost of natural gas marketing.

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

			Fair Value	
Derivative instruments:		Balance sheet line item	June 30, 2016	December 31, 2015
			(in thousands)	
Derivative assets:	Current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	$98,526	$221,161
	Related to natural gas marketing	Fair value of derivatives	313	441
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	—	57
			98,839	221,659
	Non-current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	12,673	44,292
	Related to natural gas marketing	Fair value of derivatives	72	51
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	—	44
			12,745	44,387
Total derivative assets			$111,584	$266,046
Derivative liabilities:	Current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	$21,179	$—
	Related to natural gas marketing	Fair value of derivatives	251	417
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	1,394	1,178
			22,824	1,595
	Non-current			
	Commodity contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	26,509	275
	Related to natural gas marketing	Fair value of derivatives	54	46
	Basis protection contracts			
	Related to crude oil and natural gas sales	Fair value of derivatives	267	374
			26,830	695
Total derivative liabilities			$49,654	$2,290

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

	Three Months Ended June 30,		Six Months Ended June 30,	
Condensed consolidated statement of operations line item	2016	2015	2016	2015
	(in thousands)			
Commodity price risk management gain (loss), net				

Net settlements	$53,301	$44,049	$120,132	$94,461
Net change in fair value of unsettled derivatives	(146,102)	(93,090)	(201,877)	(76,840)
Total commodity price risk management gain (loss), net	$(92,801)	$(49,041)	$(81,745)	$17,621
Sales from natural gas marketing				
Net settlements	$53	$165	$298	$396
Net change in fair value of unsettled derivatives	(299)	(124)	(519)	(293)
Total sales from natural gas marketing	$(246)	$41	$(221)	$103
Cost of natural gas marketing				
Net settlements	$(49)	$(157)	$(277)	$(375)
Net change in fair value of unsettled derivatives	346	115	571	264
Total cost of natural gas marketing	$297	$(42)	$294	$(111)

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

The following table reflects the impact of netting agreements on gross derivative assets and liabilities:

As of June 30, 2016	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	$111,584	$(30,404)	$81,180
Liability derivatives:			
Derivative instruments, at fair value	$49,654	$(30,404)	$19,250

As of December 31, 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	$266,046	$(1,921)	$264,125
Liability derivatives:			
Derivative instruments, at fair value	$2,290	$(1,921)	$369

NOTE 5 - PROPERTIES AND EQUIPMENT

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

	June 30, 2016	December 31, 2015

	(in thousands)	
Properties and equipment, net:		
Crude oil and natural gas properties		
Proved	$3,067,916	$2,881,189
Unproved	61,202	60,498
Total crude oil and natural gas properties	3,129,118	2,941,687
Equipment and other	31,566	30,098
Land and buildings	9,040	12,667
Construction in progress	117,190	113,115
Properties and equipment, at cost	3,286,914	3,097,567
Accumulated DD&A	(1,356,319)	(1,157,015)
Properties and equipment, net	$1,930,595	$1,940,552

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)			
Impairment of proved and unproved properties	$1,084	$1,631	$2,053	$1,919
Amortization of individually insignificant unproved properties	54	2,773	86	5,257
Impairment of crude oil and natural gas properties	1,138	4,404	2,139	7,176
Land and buildings	3,032	—	3,032	—
Impairment of properties and equipment	$4,170	$4,404	$5,171	$7,176

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 the three and six months ended June 30, 2016 was a 37.9% and 37.5% benefit on loss compared to a 39.1% and 39.4% benefit on loss for the three and six months ended June 30, 2015. The effective tax rate for the three and six months ended June 30, 2016 is based upon a full year forecasted tax benefit on loss and is greater than the statutory federal tax rate, primarily due to state taxes and percentage depletion, partially offset by nondeductible officers’ compensation and nondeductible lobbying expenses. The effective tax rate for the three and six months ended June 30, 2015 differs from the statutory rate primarily due to state taxes and nondeductible officers' compensation, partially offset by percentage depletion and domestic production deduction. There were no significant discrete items recorded during the three and six months ended June 30, 2016 or June 30, 2015.

As of June 30, 2016, there is 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 to voluntarily participate in the Internal Revenue Service's ("IRS") Compliance Assurance Program for the 2015 and 2016 tax years. With respect to the 2014 tax year, we have agreed to a post filing adjustment with the IRS which resulted in an immaterial tax payment for the 2014 tax year. The IRS has fully accepted the 2014 federal return, as adjusted.

NOTE 7 - LONG-TERM DEBT

Long-term debt consisted of the following as of:

	June 30, 2016	December 31, 2015
	(in thousands)	
Senior notes:		

3.25% Convertible senior notes due 2016:		
Principal amount	$—	$115,000
Unamortized discount	—	(1,852)
Unamortized debt issuance costs	—	(208)
3.25% Convertible senior notes due 2016, net of discount and unamortized debt issuance costs	—	112,940
7.75% Senior notes due 2022:		
Principal amount	500,000	500,000
Unamortized debt issuance costs	(7,003)	(7,563)
7.75% Senior notes due 2022, net of unamortized debt issuance costs	492,997	492,437
Total senior notes	492,997	605,377
Revolving credit facility	—	37,000
Total debt, net of discount and unamortized debt issuance costs	492,997	642,377
Less current portion of long-term debt	—	112,940
Long-term debt	$492,997	$529,437

Senior Notes

3.25% Convertible Senior Notes Due 2016. In November 2010, we issued $115 million aggregate principal amount of 3.25% convertible senior notes due 2016 (the "Convertible Notes") in a private placement to qualified institutional buyers. The maturity for the payment of principal was May 15, 2016. At December 31, 2015, our indebtedness included the Convertible Notes. Upon settlement in May 2016, we paid the aggregate principal amount of the Convertible Notes, plus cash for fractional shares, totaling approximately $115.0 million, utilizing proceeds from our March 2016 equity offering. Additionally, we issued 792,406 shares of common stock for the $47.9 million excess conversion value. See Note 11, Common Stock, for more information.

7.75% Senior Notes Due 2022. In October 2012, we issued $500 million aggregate principal amount of 7.75% senior notes due October 15, 2022 (the “2022 Senior Notes”) in a private placement to qualified institutional buyers. The 2022 Senior Notes accrue interest from the date of issuance and interest is payable semi-annually in arrears on 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 June 30, 2016, we were in compliance with all covenants related to the 2022 Senior Notes and expect to remain in compliance throughout the next 12-month period.

Credit Facility

Revolving Credit Facility. We are party to a Third Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A. as administrative agent, and other lenders party thereto (sometimes referred to as the "revolving credit facility"). The revolving credit facility matures in May 2020 and 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. In May 2016, we completed the semi-annual redetermination of our revolving credit facility by the lenders, which 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 mortgages of certain producing crude oil and natural gas properties. Our affiliated partnerships are not guarantors of our obligations under the revolving credit facility.

We had no outstanding balance on our revolving credit facility as of June 30, 2016, compared to $37.0 million outstanding as of December 31, 2015. 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 2.6% per annum as of December 31, 2015.

As of June 30, 2016, 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 June 30, 2016, the available funds under our revolving credit facility, including the reduction for the $11.7 million letter of credit, was $438.3 million. In addition to our currently elected commitment of $450 million, we have an additional $250 million of borrowing base availability under the revolving credit facility, subject to certain terms and conditions of the agreement.

The revolving credit facility contains covenants customary for agreements of this type, with the most restrictive being certain financial tests on a quarterly basis. The financial tests, as defined per the revolving credit facility, include requirements to: (a) maintain a minimum current ratio of 1.00 to 1.00 and (b) not exceed a maximum leverage ratio of 4.25 to 1.00. As of June 30, 2016, we were in compliance with all the revolving credit facility covenants and expect to remain in compliance throughout the next 12-month period.

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NOTE 8 - CAPITAL LEASES

We periodically enter into non-cancelable lease agreements for vehicles utilized by our operations and field personnel. These leases are being accounted for as capital leases, 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 June 30, 2016:

	Amount (in thousands)
Vehicles	$ 2,674
Accumulated depreciation	(464)
	$ 2,210

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 June 30,	Amount (in thousands)
2017	$ 820
2018	1,075
2019	734
	2,629
Less executory cost	(105)
Less amount representing interest	(305)
Present value of minimum lease payments	$ 2,219
Short-term capital lease obligations	$ 606
Long-term capital lease obligations	1,613
	$ 2,219

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.

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, 2016	$ 89,492

Obligations incurred with development activities	843
Accretion expense	3,623
Obligations discharged with disposal of properties and asset retirements	(5,475)
Balance end of period, June 30, 2016	88,483
Less current portion	(6,900)
Long-term portion	$ 81,583

Our estimated asset retirement obligation liability is based on historical experience in plugging and abandoning wells, estimated economic lives and estimated plugging and abandonment cost considering federal and state regulatory requirements in effect. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. In 2016, the credit-adjusted risk-free rates used to discount our plugging and abandonment liabilities ranged from 7.6% to 8.0%. In periods subsequent to initial measurement of the liability, we must recognize period-to-period changes in the liability resulting from the passage of time, revisions to either the amount of the original estimate of undiscounted cash flows or changes in inflation factors and changes to our credit-adjusted risk-free rate as market conditions warrant. 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 natural gas prices continue to remain depressed, certain third-party producers under our Gas Marketing segment have begun and continue to experience financial distress, which has led to certain contractual defaults and litigation; however, to date, we have had no material counterparty default losses. As of June 30, 2016, we have recorded an allowance for doubtful accounts of approximately $0.9 million. We have initiated several legal actions for breach of contract, collection, and related claims against certain third-party producers that are delinquent in their payment obligations, which have to date resulted in one default judgment. There have been no collections received to date and and some of the third-party producers have shut-in their wells.

A group of independent West Virginia natural gas producers has filed, but not served on RNG, a complaint in Marshall County, West Virginia, naming Dominion Transmission, Inc. (“Dominion”), certain entities affiliated with Dominion, and RNG as defendants, alleging various contractual, fiduciary and related claims against the defendants, all of which are associated with firm transportation contracts entered into by plaintiffs and relating to pipelines owned and operated by Dominion and its affiliates. RNG is aware of this lawsuit filing but has not received formal service of process which commences the litigation against RNG. Furthermore, at this time, RNG is unable to estimate any potential damages associated with the claims, but believes the complaint is without merit and intends to vigorously pursue its defenses.

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

Area	For the Twelve Months Ending June 30, 2017	2018	2019	2020	2021 and Through Expiration	Total	Expiration Date
Natural gas (MMcf)							
Gas Marketing segment	7,117	7,117	7,117	7,136	15,138	43,625	August 31, 2022
Utica Shale	2,738	2,738	2,738	2,745	8,444	19,403	July 22, 2023
Total	9,855	9,855	9,855	9,881	23,582	63,028	
Crude oil (MBbls)							
Wattenberg Field	2,413	2,413	2,413	2,421	—	9,660	June 30, 2020
Dollar commitment (in thousands)	$17,573	$16,536	$16,324	$16,369	$ 9,052	$75,854	

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.

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 and simulated drills to identify changes in our environmental risk profile. Liabilities are recorded when environmental damages resulting from past events that require remediation are probable to require remediation and the costs can be reasonably estimated. As of June 30, 2016 and December 31, 2015, we had accrued environmental liabilities in the amount of $4.0 million and $4.1 million, respectively, included in other accrued expenses on the condensed consolidated balance sheets. We are not aware of any environmental claims existing as of June 30, 2016 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 U.S. Environmental Protection Agency ("EPA"). The Information Request sought, among other things, information related to the design, operation, and maintenance of our production facilities in the Denver-Julesburg Basin of Colorado. The Information Request focused on historical operation and design information for 46 of our production facilities and asks that we conduct sampling and analyses at the identified 46 facilities. We responded to

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the Information Request in January 2016. We continue to meet with the EPA and provide additional information, but cannot predict the outcome of this matter at this time.

In addition, in December 2015, we received a Compliance Advisory pursuant to C.R.S. § 25-7-115(2) from the Colorado Department of Public Health and Environment's Air Quality Control Commission's Air Pollution Control Division alleging that we failed to design, operate, and maintain certain condensate collection, storage, processing and handling operations to minimize leakage of volatile organic compounds to the maximum extent possible at 65 facilities consistent with applicable standards under Colorado law. We are in the process of responding to the advisory, and working with the agency on specific response processes, but cannot predict the outcome of this matter at this time.

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 2016, we completed a public offering of 5,922,500 shares of our common stock, par value $0.01 per share, at a price to us of $50.11 per share. Net proceeds of the offering were $296.6 million, after deducting offering expenses and underwriting discounts, of which $59,225 is included in common shares-par value and $296.5 million is included in additional paid-in capital ("APIC") on the June 30, 2016 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. Upon maturity of our Convertible Notes in May 2016, we paid the aggregate principal amount, plus cash for fractional shares, totaling approximately $115.0 million, utilizing proceeds from the offering. Additionally, we issued 792,406 shares of common stock for the premium in excess of the conversion price of $42.40 per share.

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 APIC on the condensed consolidated balance sheets. The shares were issued pursuant to the 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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)			
Stock-based compensation expense	$6,444	$5,097	$11,126	$9,465

Income tax benefit	(2,452)	(1,936)	(4,233)	(3,595)
Net stock-based compensation expense	$3,992	$3,161	$6,893	$5,870

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.

In January 2016, the Compensation Committee awarded 58,709 SARs to our executive officers. The fair value of each SAR award was estimated on the date of grant using a Black-Scholes pricing model using the following assumptions:

	Six Months Ended June 30,	
	2016	2015
Expected term of award	6.0 years	5.2 years
Risk-free interest rate	1.8 %	1.4 %
Expected volatility	54.5 %	58.0 %
Weighted-average grant date fair value per share	$26.96	$22.23

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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 all periods presented:

	Six Months Ended June 30,							
	2016				2015			
	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,	326,453	$ 38.99			279,011	$ 38.77		
Awarded	58,709	51.63			68,274	39.63		
Exercised	(114,853)	38.71		$ 2,488	—	—		
Outstanding at June 30,	270,309	41.86	7.4	4,258	347,285	38.94	7.8	$ 5,107
Vested and expected to vest at June 30,	263,546	41.70	7.4	4,193	339,980	38.88	7.7	5,019
Exercisable at June 30,	162,895	38.31	6.4	3,144	191,149	35.68	6.9	3,433

Total compensation cost related to SARs granted, net of estimated forfeitures, and not yet recognized in our condensed consolidated statement of operations as of June 30, 2016 was $2.0 million. The cost is expected to be recognized over a weighted-average period of 2.1 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 generally vest ratably on each anniversary following the grant date provided that a participant is continuously employed.

In January 2016, the Compensation Committee awarded to our executive officers a total of 61,634 time-based restricted shares that vest ratably over a three-year period ending in January 2019.

The following table presents the changes in non-vested time-based awards to all employees, including executive officers, for the six months ended June 30, 2016:

	Shares	Weighted-Average Grant Date Fair Value
Non-vested at December 31, 2015	525,081	$ 50.23
Granted	267,379	57.11

Vested	(233,269)	49.74
Forfeited	(12,306)	55.27
Non-vested at June 30, 2016	546,885	53.69

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 Six Months Ended June 30,	
	2016	2015
	(in thousands, except per share data)	
Total intrinsic value of time-based awards vested	$13,314	$10,126
Total intrinsic value of time-based awards non-vested	31,506	34,556
Market price per common share as of June 30,	57.61	53.64
Weighted-average grant date fair value per share	57.11	48.54

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - Continued

Total compensation cost related to non-vested time-based awards, net of estimated forfeitures, and not yet recognized in our condensed consolidated statements of operations as of June 30, 2016 was $21.7 million. This cost is expected to be recognized over a weighted-average period of 2.1 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 2016, the Compensation Committee awarded a total of 24,280 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, 2018 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 was computed using the Monte Carlo pricing model using the following assumptions:

	Six Months Ended June 30,	
	2016	2015
Expected term of award	3 years	3 years
Risk-free interest rate	1.2 %	0.9 %
Expected volatility	52.3 %	53.0 %
Weighted-average grant date fair value per share	$72.54	$66.16

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 six months ended June 30, 2016:

	Shares	Weighted-Average Grant Date Fair Value per Share
Non-vested at December 31, 2015	71,549	$ 63.60
Granted	24,280	72.54
Vested	(11,283)	98.50
Non-vested at June 30, 2016	84,546	61.51

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 Six Months Ended June 30,	
	2016	2015
	(in thousands, except per share data)	
Total intrinsic value of market-based awards vested	$ 1,174	$ —
Total intrinsic value of market-based awards non-vested	4,871	6,068
Market price per common share as of June 30,	57.61	53.64
Weighted-average grant date fair value per share	72.54	66.16

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 June 30, 2016 was $2.2 million. This cost is expected to be recognized over a weighted-average period of 2.0 years.

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

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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)			
Weighted-average common shares outstanding - basic	46,742	40,035	44,175	38,202
Weighted-average common shares and equivalents outstanding - diluted	46,742	40,035	44,175	38,202

We reported a net loss for the three and six months ended June 30, 2016 and 2015, respectively. 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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)			
Weighted-average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:				
Restricted stock	768	871	745	832
Convertible notes	358	677	478	523
Other equity-based awards	103	118	105	99
Total anti-dilutive common share equivalents	1,229	1,666	1,328	1,454

In November 2010, we issued our Convertible Notes, which gave 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 matured in May 2016. See Note 7, Long-Term Debt, for additional information. Prior to maturity, the Convertible Notes were included in the diluted earnings per share calculation using the treasury stock method if the average market share price exceeded the $42.40 conversion price during the period presented. Shares issuable upon conversion of the Convertible Notes were excluded from the diluted earnings per share calculation for the three and six months ended June 30, 2016 and 2015 as the effect would be anti-dilutive to our earnings per share.

NOTE 13 - 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 properties and equipment, 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 unrelated third-parties. 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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)			
Segment revenues:				
Oil and gas exploration and production	$18,218	$48,437	$106,878	$189,836
Gas marketing	1,879	2,523	4,050	5,756
Total revenues	$20,097	$50,960	$110,928	$195,592
Segment income (loss) before income taxes:				
Oil and gas exploration and production	$(118,508)	$(44,364)	$(152,541)	$16,161
Gas marketing	(246)	(313)	(653)	(338)
Unallocated	(35,023)	(32,309)	(113,952)	(65,024)
Loss before income taxes	$(153,777)	$(76,986)	$(267,146)	$(49,201)

	June 30, 2016	December 31, 2015
	(in thousands)	
Segment assets:		
Oil and gas exploration and production	$2,244,799	$ 2,294,288
Gas marketing	4,117	4,217
Unallocated	22,754	72,038
Total assets	$2,271,670	$ 2,370,543

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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 increased substantially to 5.2 MMboe and 9.8 MMboe for the three and six months ended June 30, 2016, respectively, representing increases of 54% and 56%, respectively, as compared to the three and six months ended June 30, 2015. The increase in production volumes was primarily attributable to our successful horizontal Niobrara and Codell drilling program in the Wattenberg Field. Crude oil production increased 26% and 35% for the three and six months ended June 30, 2016, respectively, compared to the same prior year periods. Crude oil production comprised approximately 38% and 40% of total production in the three and six months ended June 30, 2016. Our ratio of crude oil production to total production decreased as expected as we shifted our focus to the higher gas to oil ratio inner core area of the Wattenberg Field. We expect our ratio of crude oil to total production to increase during the second half of 2016 as we move drilling operations back toward the middle core area of the Wattenberg Field. Natural gas production increased 73% and 69% in the three and six months ended June 30, 2016, respectively, compared to the three and six months ended June 30, 2015. NGL production increased 93% and 85% for the three and six months ended June 30, 2016, respectively, compared to the same prior year periods. Our inner core wells have shown stronger wet gas production than anticipated, which has contributed to the growth of gas and NGL production. The majority of our wells turned-in-line during the three months ended March 31, 2016 occurred toward the end of the quarter, while wells turned-in-line during the three months ended June 30, 2016 occurred more evenly throughout the period. As expected, this drove our quarter-over-quarter production increase of approximately 0.6 Mboe, or 14%. We expect the timing of the wells to be turned-in-line during the three months ended September 30, 2016 to be relatively even, similar to the timing for the three months ended June 30, 2016. We expect a modest increase in production for the third quarter as compared to the second quarter. For the month ended June 30, 2016, our average production rate was 58 MBoe per day, up from 42 MBoe per day for the month ended June 30, 2015.

Crude oil, natural gas and NGLs sales, coupled with the impact of settled derivatives, increased during the three and six months ended June 30, 2016 relative to the same prior year periods. Crude oil, natural gas and NGLs sales increased to $110.8 million and $186.2 million during the three and six months ended June 30, 2016 compared to $96.9 million and $171.0 million in the same prior year periods due to 54% and 56% increases in production, respectively, offset in part by 26% and 30% decreases, respectively, in the realized price per barrel of crude oil equivalent ("Boe"). The realized prices per Boe were $21.33 and $19.07 for the three and six months ended June 30, 2016, respectively, compared to $28.79 and $27.32, respectively, for the same prior year periods. Positive net settlements on derivatives increased to $53.3 million and $120.1 million during the three and six months ended June 30, 2016, respectively, compared to positive net settlements on derivatives of $44.1 million and $94.5 million in the same prior year periods, due to lower crude oil and natural gas index settlement prices. As a result of these increases, crude oil, natural gas and NGLs sales and the impact of net settled derivatives totaled $164.1 million and $306.3 million during the three and six months ended June 30, 2016, respectively, compared to $141.0 million and $265.5 million during the three and six months ended June 30, 2015, respectively. This represents increases of 16% and 15% during the three and six months ended June 30, 2016, respectively, compared to the same prior year periods. The realized prices per Boe, including the impact of net settlements on derivatives, were $31.58 and $31.36 for the three and six months ended June 30, 2016, respectively, compared to $41.88 and $42.40 for the same prior year periods, respectively.

Additional significant changes impacting our results of operations for the three months ended June 30, 2016 include the following:

- Negative net change in the fair value of unsettled derivative positions during the three months ended June 30, 2016 was $146.1 million compared to a negative net change in the fair value of unsettled derivative positions of $93.1 million during the same prior year period. The decrease in fair value of unsettled derivative positions was primarily attributable to a more significant upward shift in the crude oil and natural gas forward curves that occurred during the current quarter as compared to the three months ended June 30, 2015; and
- Depreciation, depletion and amortization expense increased to $107.0 million during the three months ended June 30, 2016 compared to $70.1 million in the same prior year period, primarily due to increased production.

Additional significant changes impacting our results of operations for the six months ended June 30, 2016 include the following:

- Negative net change in the fair value of unsettled derivative positions during the six months ended June 30, 2016 was $201.8 million compared to a negative net change in the fair value of unsettled derivative positions of $76.8 million during the same prior year period. The decrease in fair value of unsettled derivative positions was primarily attributable to a higher beginning-of-period fair value of derivatives instruments that settled during the six months ended June 30, 2016 and an upward shift in the crude oil and natural gas forward curves that occurred during the second quarter of 2016;
- Depreciation, depletion and amortization expense increased to $204.4 million during the six months ended June 30, 2016 compared to $125.9 million in the same prior year period, primarily due to increased production and, to a lesser extent, a higher weighted-average depreciation, depletion and amortization rate; and
- During the first quarter of 2016, we determined that collection of two third-party notes receivable arising from the sale of our interest in properties in the Marcellus Shale was not reasonably assured based upon current market conditions and new information

made available to us. As a result, we recognized a provision and recorded an allowance for uncollectible notes receivable for the $44.7 million outstanding balance as of March 31, 2016. As of June 30, 2016, there has been no change to our assessment of the collectibility of the notes. See Note 3, Fair Value of Financial Instruments - Notes Receivable, to our condensed consolidated financial statements included elsewhere in this report for additional information.

In March 2016, we completed a public offering of 5,922,500 shares of our common stock at a price to us of $50.11 per share. Net proceeds of the offering were $296.6 million, after deducting offering expenses and underwriting discounts. We used a portion of the net proceeds of the offering to repay all amounts then outstanding on our revolving credit facility, the principal amount owed upon the maturity of the Convertible Notes in May 2016 and retained the remainder for general corporate purposes.

The Convertible Notes matured in May 2016. We paid the aggregate principal amount, plus cash for fractional shares, totaling approximately $115 million, utilizing proceeds from the offering. Additionally, we issued 792,406 shares of common stock for the excess conversion value.

In June 2016, we entered into definitive agreements with Noble Energy, Inc. and certain of its subsidiaries ("Noble") to consolidate certain acreage positions in the core area of the Wattenberg Field. Pursuant to the terms of the agreements, this strategic trade includes leasehold acreage only, and does not include production or wellbores. We expect to receive approximately 13,500 net acres in exchange for approximately 11,700 net acres, subject, in each case, to title examination and other customary adjustments. The difference in net acres is primarily due to variances in net revenue interests. This acreage trade is expected to increase opportunities for longer horizontal laterals with significantly increased working interests, while minimizing potential surface impact. We anticipate closing this transaction early in the fourth quarter of 2016.

Available liquidity as of June 30, 2016 was $547.4 million compared to $402.2 million as of December 31, 2015. Available liquidity as of June 30, 2016 is comprised of $109.1 million of cash and cash equivalents and $438.3 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 May 2016, we completed the semi-annual redetermination of our revolving credit facility by the lenders, which resulted in the reaffirmation of the borrowing base at $700 million. We have elected to maintain the aggregate commitment level at $450 million. With our current derivative position, available liquidity and expected cash flows from operations, we believe we have sufficient liquidity to allow us to fund our operations and execute our expected 2016 development program.

Operational Overview

Drilling Activities. During the six months ended June 30, 2016, we continued to execute our strategic plan to grow production while preserving our financial strength and liquidity by managing our capital spending to approximate our cash flows from operations. Through July 2016, we ran four automated drilling rigs in the Wattenberg Field. During the six months ended June 30, 2016, we spud 76 horizontal wells and turned-in-line 81 horizontal wells in the Wattenberg Field. We also participated in 24 gross, 6.5 net, horizontal non-operated wells that were spud and 12 gross, 3.2 net, horizontal non-operated wells which were turned-in-line. During the six months ended June 30, 2016, we drilled and completed five wells in the Utica Shale, three of which were turned-in-line during the period. Of these three wells, one is a 10,000 foot lateral well located in Guernsey County and two are 6,000 foot lateral wells located in Washington County. We plan to turn-in-line the two remaining wells over the next several months.

2016 Operational Outlook

We are raising the mid-point of our production range and now expect our production for 2016 to be between 21.0 MMBoe and 22.0 MMBoe and that our production rate will average approximately 58,000 to 60,000 Boe per day. Our revised 2016 capital forecast of $400 million to $420 million is focused on continuing to provide value-driven production growth by exploiting our substantial inventory of reasonable rate-of-return projects in the Wattenberg Field.

Wattenberg Field. As a result of increased working interests in planned wells resulting from the anticipated acreage exchange with Noble, we reduced the number of rigs in the Wattenberg Field drilling plan to three beginning in August 2016. With the reduction from four drilling rigs to three in the Wattenberg Field, our 2016 capital forecast has been slightly reduced to approximately $375 million in the field, comprised of approximately $340 million for our operated drilling program and approximately $20 million for non-operated projects. The remainder of the Wattenberg Field capital is expected to be used for leasing, workover projects and other capital improvements. We plan to spud 128 and turn-in-line 140 horizontal Niobrara or Codell wells and participate in approximately 15 gross, 4.0 net, non-operated horizontal opportunities in 2016. During the six months ended June 30, 2016, we invested approximately $182 million, or approximately 49%, of our 2016 capital forecast for the Wattenberg Field.

Utica Shale. As of June 30, 2016, all of our drilling and completion activity in the Utica Shale for 2016 has been completed as described above. We plan to turn-in-line the two remaining wells during the second half of 2016 once midstream pipeline facilities are available for connection. Additionally, we plan to perform modest amounts of drill site preparation and to pursue infill leasing opportunities. During the six months ended June 30, 2016, we have invested approximately $25 million of our total 2016 capital forecast for the Utica Shale of approximately $30 million.

2016 Operational Flexibility

In December 2015, the Board of Directors approved our 2016 development plan. This plan, which primarily focuses on the drilling program in the Wattenberg Field, was based upon our goal to preserve our balance sheet by managing our capital spending to approximate our cash flows from operations. Additionally, with the proceeds from our March 2016 equity offering and settlement of our convertible notes in May 2016, we believe we have further strengthened our balance sheet, while concurrently increasing production and cash flows.

We maintain significant operational flexibility to reduce the pace of our capital spending. We will continue to monitor future commodity prices, and should prices remain depressed or further deteriorate, we believe an adjustment to our development plan may be appropriate. We believe we have ample opportunities to reduce capital spending, including but not limited to: working with our vendors to achieve further cost reductions; reducing the number of rigs being utilized in our drilling program; and/or managing our completion schedule. The production impact of reduced 2016 capital spending would be felt primarily in 2017 and thereafter, as our anticipated long-term production growth would likely be reduced. This operational flexibility is maintained with little exposure to incurring additional costs, given that all of our acreage in the Wattenberg Field is held by production, a reduction in rigs would not cause us to incur substantial idling costs as our rig commitments are short term (30 to 90 days), and we do not anticipate having additional material unfulfilled transportation commitment fees.

Ballot Initiative Update

Certain interest groups in Colorado opposed to oil and natural gas development generally, and hydraulic fracturing in particular, have advanced various alternatives for ballot initiatives which would result in significantly limiting or preventing oil and natural gas development in the state. Proponents of two such initiatives have submitted signatures in an effort to qualify the initiatives to appear on the ballot in November 2016. The signatures are subject to a verification process to be conducted by the Colorado Secretary of State. This process could take up to 30 days. We do not know what the outcome of this process will be. However, based on unofficial reports regarding the number of signatures submitted and the expectation that some signatures will be invalidated, we believe there is a substantial likelihood that the initiatives will not qualify for the ballot. If the initiatives qualify and are approved by the voters of Colorado, the proposals will take effect by the end of 2016.

One of the initiatives that could appear on the ballot, which we refer to as the “local control” initiative, would amend the state constitution to give city, town and county governments the right to regulate, or to ban, oil and gas development and production within their boundaries, notwithstanding rules and approvals to the contrary at the state level. The other initiative, which we refer to as the “setback” initiative, would amend the state constitution to require all new oil and gas development facilities to be located at least 2,500 feet away from any occupied structure or “area of special concern,” broadly defined to include public and community drinking water sources, lakes, rivers, perennial or intermittent streams, creeks, irrigation canals, riparian areas, playgrounds, permanent sports fields, amphitheaters, public parks and public open space. The current minimum required setback between oil and gas wells and occupied structures is generally 500 feet. If implemented, the 2,500 foot setback proposal would effectively prohibit the vast majority of our planned future drilling activities and would therefore make it impossible to pursue our current development plans. The local control proposal would potentially have a similar effect, depending on the nature and extent of regulations implemented by relevant local governmental authorities.

Because substantially all of our current operations and reserves are located in Colorado, the risks we face with respect to these proposals, and possible similar future proposals, are greater than those of our competitors with more geographically diverse operations. We cannot predict the outcome of the potentially pending initiatives or possible future regulatory developments.

See Part II, Item1A, Risk Factors, for additional information regarding the ballot initiatives.

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PDC ENERGY, INC.

Results of Operations

Summary Operating Results

The following table presents selected information regarding our operating results:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Percentage Change	2016	2015	Percentage Change
	(dollars in millions, except per unit data)					
Production (1)						
Crude oil (MBbls)	1,992.6	1,581.4	26.0 %	3,900.4	2,888.1	35.1 %
Natural gas (MMcf)	12,672.8	7,323.7	73.0 %	23,350.8	13,848.1	68.6 %
NGLs (MBbls)	1,092.5	565.0	93.4 %	1,974.7	1,065.5	85.3 %
Crude oil equivalent (MBoe) (2)	5,197.1	3,367.1	54.3 %	9,766.8	6,261.7	56.0 %
Average MBoe per day	57.1	37.0	54.3 %	53.7	34.6	56.0 %
Crude Oil, Natural Gas and NGLs Sales						
Crude oil	$80.4	$76.4	5.2 %	$134.4	$128.4	4.7 %
Natural gas	17.4	14.9	16.8 %	32.3	30.6	5.6 %
NGLs	13.0	5.6	132.1 %	19.5	12.0	62.5 %
Total crude oil, natural gas and NGLs sales	$110.8	$96.9	14.3 %	$186.2	$171.0	8.9 %
Net Settlements on Derivatives (3)						
Crude oil	$38.7	$37.0	4.6 %	$92.0	$81.7	12.6 %
Natural gas	14.6	7.1	105.6 %	28.1	12.8	119.5 %
Total net settlements on derivatives	$53.3	$44.1	20.9 %	$120.1	$94.5	27.1 %
Average Sales Price (excluding net settlements on derivatives)						
Crude oil (per Bbl)	$40.37	$48.31	(16.4)%	$34.46	$44.47	(22.5)%
Natural gas (per Mcf)	1.37	2.03	(32.5)%	1.38	2.21	(37.6)%
NGLs (per Bbl)	11.93	10.01	19.2 %	9.89	11.23	(11.9)%
Crude oil equivalent (per Boe)	21.33	28.79	(25.9)%	19.07	27.32	(30.2)%
Average Lease Operating Expenses (per Boe) (4)						
Wattenberg Field	$2.66	$3.92	(32.1)%	$3.00	$4.80	(37.5)%
Utica Shale	2.08	1.55	34.2 %	2.28	1.67	36.5 %
Weighted-average	2.63	3.71	(29.1)%	2.97	4.52	(34.3)%
Natural Gas Marketing Contribution Margin (5)	$(0.2)	$(0.3)	(33.3)%	$(0.6)	$(0.3)	(100.0)%
Other Costs and Expenses						
Production taxes	$6.0	$3.8	57.5 %	$10.1	$7.7	30.8 %
Transportation, gathering and processing expenses	4.5	1.3	241.4 %	8.5	2.6	221.5 %
Impairment of properties and equipment	4.2	4.4	(5.3)%	5.2	7.2	(27.9)%
General and administrative expense	23.6	20.7	13.8 %	46.4	41.8	11.0 %
Depreciation, depletion and amortization	107.0	70.1	52.6 %	204.4	125.9	62.3 %
Provision for uncollectible notes receivable	—	—	*	44.7	—	*

Interest expense	$10.7	$11.6	(7.7)%	$22.6	$23.3	(3.1)%

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

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

Crude Oil, Natural Gas and NGLs Sales

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

	Three Months Ended June 30,			Six Months Ended June 30,		
Production by Operating Region	2016	2015	Percentage Change	2016	2015	Percentage Change
Crude oil (MBbls)						
Wattenberg Field	1,894.0	1,449.7	30.6 %	3,712.2	2,640.9	40.6 %
Utica Shale	98.6	131.7	(25.1)%	188.2	247.2	(23.9)%
Total	1,992.6	1,581.4	26.0 %	3,900.4	2,888.1	35.1 %
Natural gas (MMcf)						
Wattenberg Field	12,097.8	6,651.1	81.9 %	22,268.2	12,562.4	77.3 %
Utica Shale	575.0	672.6	(14.5)%	1,082.6	1,285.7	(15.8)%
Total	12,672.8	7,323.7	73.0 %	23,350.8	13,848.1	68.6 %
NGLs (MBbls)						
Wattenberg Field	1,047.3	509.9	105.4 %	1,887.4	961.8	96.2 %
Utica Shale	45.2	55.1	(18.0)%	87.3	103.7	(15.8)%
Total	1,092.5	565.0	93.4 %	1,974.7	1,065.5	85.3 %
Crude oil equivalent (MBoe)						
Wattenberg Field	4,957.5	3,068.2	61.6 %	9,310.9	5,696.5	63.4 %
Utica Shale	239.6	298.9	(19.8)%	455.9	565.2	(19.3)%
Total	5,197.1	3,367.1	54.3 %	9,766.8	6,261.7	56.0 %

Amounts may not recalculate due to rounding.

	Three Months Ended June 30,			Six Months Ended June 30,		
Average Sales Price by Operating Region (excluding net settlements on derivatives)	2016	2015	Percentage Change	2016	2015	Percentage Change
Crude oil (per Bbl)						
Wattenberg Field	$40.41	$48.09	(16.0)%	$34.51	$44.41	(22.3)%
Utica Shale	39.57	50.78	(22.1)%	33.44	45.12	(25.9)%
Weighted-average price	40.37	48.31	(16.4)%	34.46	44.47	(22.5)%
Natural gas (per Mcf)						
Wattenberg Field	$1.36	$2.03	(33.0)%	$1.38	$2.21	(37.6)%
Utica Shale	1.58	2.06	(23.3)%	1.51	2.22	(32.0)%
Weighted-average price	1.37	2.03	(32.5)%	1.38	2.21	(37.6)%
NGLs (per Bbl)						
Wattenberg Field	$11.87	$10.01	18.6 %	$9.78	$10.91	(10.4)%
Utica Shale	13.27	9.95	33.4 %	12.29	14.17	(13.3)%
Weighted-average price	11.93	10.01	19.2 %	9.89	11.23	(11.9)%
Crude oil equivalent (per Boe)						
Wattenberg Field	$21.27	$28.78	(26.1)%	$19.03	$27.31	(30.3)%
Utica Shale	22.59	28.86	(21.7)%	19.75	27.38	(27.9)%
Weighted-average price	21.33	28.79	(25.9)%	19.07	27.32	(30.2)%

Amounts may not recalculate due to rounding.

For the three and six months ended June 30, 2016, crude oil, natural gas and NGLs sales revenue increased compared to the three and six months ended June 30, 2015 due to the following:

	June 30, 2016	
	Three Months Ended	Six Months Ended
	(in millions)	
Increase in production	$36.0	$ 76.2
Decrease in average crude oil price	(15.8)	(39.0)
Decrease in average natural gas price	(8.4)	(19.4)
Increase (decrease) in average NGLs price	2.1	(2.6)
Total increase in crude oil, natural gas and NGLs sales revenue	$13.9	$ 15.2

Production for the second quarter of 2016 was 5.2 million Boe, up from 3.4 million Boe in the second quarter of 2015. Year-to-date, production was 9.8 million Boe, up from 6.3 million Boe in the first six months of 2015. Production increased as a result of continued drilling and completion activities as discussed in Operational Overview. Gathering system line pressures decreased following the commissioning of DCP's Lucerne II plant in the summer of 2015, down to levels that were consistent with our projections. We continued to experience 24% lower line pressures in the second quarter of 2016 as compared to the comparable period of 2015 on our primary service provider's system. Line pressures averaged 225 pounds per square inch gage ("psig") during the second quarter of 2015 and averaged 170 psig during the second quarter of 2016. Line pressures began to build during the quarter as system volumes increased and the region experienced warmer weather. Other contributing factors to the increase in line pressures were our primary service provider experiencing significant unexpected downtime during the quarter on some of its major plants, as well as performing extensive scheduled maintenance on one of its higher capacity gas plants. As a result of the increased line pressures, we experienced a curtailment of our legacy vertical well gas production of approximately 1.2 MMcf per day, or 6% of our vertical production, at the end of June, representing approximately 0.5% of our total Wattenberg Field gas production, along with associated oil production. The 170 psig average line pressure experienced during the quarter had negligible impact on our horizontal production. We expect the gathering system pressures on the primary service provider's system to stabilize and then decrease as cooler weather arrives by the end of the third quarter of 2016.

Our secondary midstream service provider, which currently gathers and processes approximately 36% of our Wattenberg Field gas, has limited its capital program in 2016, which has resulted in a curtailment of approximately 10 MMcf per day of our 2016 volumes. To help mitigate the impact of this curtailment, we have elected to contribute upfront capital of $0.6 million to our secondary midstream service provider to facilitate timely connection of certain of our well pads. We expect to be reimbursed by our secondary midstream service provider for this amount during the fourth quarter of 2016. With continued pressure on commodity prices impacting their revenue, we have seen more requests for upfront capital contributions by our third-party midstream service providers in order to ensure well connections are completed in a timely manner. We expect this trend to continue, and we will evaluate these requests on an individual basis. 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. Falling commodity prices have resulted in reduced investment in midstream facilities by some third parties, increasing the risk that sufficient midstream infrastructure will not be available in future periods.

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

NGL prices are among the most volatile of all commodity prices. While the price of crude oil decreased during the first half of 2016 compared to the first half of 2015, prices increased substantially during the second quarter of 2016 as compared to the first quarter of 2016 as the number of U.S. crude oil rigs and inventories declined. Natural gas prices decreased during the first half of 2016 when compared to the same prior year period. Although we did experience improved pricing by the end of the second quarter of 2016, due to an oversupply of nearly all domestic NGLs products, our average realized sales price for NGLs during the first half of 2016 reflected the same low levels seen during the last quarter of 2015. With the initiation of ethane exports and increased demand for NGLs, we are starting to see NGL prices trend upward.

Crude oil pricing is predominately driven by the physical market, supply and demand, financial markets and national and international politics. In the Wattenberg Field, crude oil is sold under various purchase contracts with monthly and longer term pricing provisions based on NYMEX pricing, adjusted for differentials. We have entered into longer term commitments ranging from three months to six months to deliver crude oil to competitive markets and these agreements have resulted in significantly improved deductions compared to the comparable period in 2015. We continue to pursue various alternatives with respect to oil transportation, particularly in the Wattenberg Field, with a view toward further improving pricing and limiting our use of trucking of production. We began delivering crude oil in accordance with our long term commitment to the White Cliffs Pipeline, LLC ("White Cliffs") pipeline in July 2015. This is one of several agreements we have entered into to facilitate deliveries of a 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 began delivering crude oil into this pipeline during the fourth quarter of 2015 and the system was fully operational on certain wells in the first half of 2016. In the Utica Shale, crude oil and condensate is sold to local purchasers at each individual pad based on NYMEX pricing, adjusted for differentials, and is typically transported by the purchasers via truck to local refineries, rail facilities or barge loading terminals on the Ohio River.

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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. We anticipate that the significant Appalachian pipeline differentials that impact our Utica Shale natural gas will continue through 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. While NGL prices had been declining, we have seen a stabilization of prices in the second quarter of 2016. We expect NGL prices to remain stable amid indications that prices could increase later in 2016.

Our crude oil, natural gas and NGLs sales are recorded under either the “net-back” or "gross" method of accounting, depending upon the related purchase agreement. We use the "net-back" method of accounting for natural gas and NGLs, as well as the majority 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 and Saddle Butte pipelines 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 result of the White Cliffs and Saddle Butte agreements, during the six months ended June 30, 2016, our Wattenberg Field crude oil average sales price increased approximately $1.65 per barrel because we recognized the costs for transportation on the White Cliffs and Saddle Butte pipelines as an increase in transportation expense, rather than as a deduction from revenues.

Lease Operating Expenses

The $1.0 million increase in lease operating expenses during the three months ended June 30, 2016 compared to the three months ended June 30, 2015 was primarily due to an increase of $0.4 million in contract labor, $0.3 million in leased generators and $0.9 million in other lease operating expenses, offset in part by a decrease of $0.5 million in regulatory compliance projects. Lease operating expenses during the six months ended June 30, 2016 were comparable to the six months ended June 30, 2015. Lease operating expenses per Boe decreased 29% and 34% to $2.63 and $2.97 during the three and six months ended June 30, 2016, respectively, compared to $3.71 and $4.52 during the three and six months ended June 30, 2015, respectively. The significant decreases in lease operating expense per Boe were the result of production growth of 54% and 56%, respectively.

Production Taxes

Production taxes are directly related to crude oil, natural gas and NGLs sales. The $2.2 million and $2.4 million increases in production taxes during the three and six months ended June 30, 2016, respectively, compared to the three and six months ended June 30, 2015 were primarily related to the 14% and 9% increases in crude oil, natural gas and NGLs sales, respectively, and 2015 production taxes reflecting downward adjustments related to ad valorem rates for production in 2014 and 2015.

Transportation, Gathering and Processing Expenses

The $3.2 million and $5.9 million increases in transportation, gathering and processing expenses during the three and six months ended June 30, 2016, respectively, compared to the three and six months ended June 30, 2015 were mainly attributable to oil transportation cost on the White Cliffs and Saddle Butte pipelines as we began delivering crude oil on these pipelines in July 2015 and December 2015, respectively. We expect to continue to incur these oil transportation costs pursuant to our long-term transportation agreements.

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, less deductions. See Note 4, Derivative Financial Instruments, to our condensed consolidated financial statements included elsewhere in this report for a detailed presentation of our derivative positions as of June 30, 2016.

Commodity price risk management, net, includes cash settlements upon maturity of our derivative instruments and the change in fair value of unsettled derivatives related to our crude oil and natural gas production. Commodity price risk management, net, does not include derivative transactions related to our natural gas marketing, which are included in sales from and cost of natural gas marketing. See Note 3, Fair Value of Financial Instruments, and Note 4, Derivative Financial Instruments, to our condensed consolidated financial statements included elsewhere in this report for additional details of our derivative financial instruments.

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. See Note 4, Derivative Financial Instruments, to our consolidated financial statements included elsewhere in this report for a detailed description of net settlements on our various derivatives.

The following table presents net settlements and net change in fair value of unsettled derivatives included in commodity price risk management, net:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in millions)			
Commodity price risk management gain (loss), net:				
Net settlements:				
Crude oil	$38.7	$37.0	$92.0	$81.7
Natural gas	14.6	7.1	28.1	12.7
Total net settlements	53.3	44.1	120.1	94.4
Change in fair value of unsettled derivatives:				
Reclassification of settlements included in prior period changes in fair value of derivatives	(60.8)	(54.3)	(115.5)	(89.4)
Crude oil fixed price swaps	(38.2)	(24.5)	(43.9)	(1.5)
Crude oil collars	(19.6)	(8.8)	(18.9)	(0.5)
Natural gas fixed price swaps	(23.1)	(2.2)	(19.4)	12.1
Natural gas basis swaps	—	(2.5)	(0.4)	(2.0)
Natural gas collars	(4.4)	(0.8)	(3.7)	4.5
Net change in fair value of unsettled derivatives	(146.1)	(93.1)	(201.8)	(76.8)
Total commodity price risk management gain (loss), net	$(92.8)	$(49.0)	$(81.7)	$17.6

Impairment of Properties and Equipment

The following table sets forth the major components of our impairment of properties and equipment expense:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in millions)			
Impairment of proved and unproved properties	$1.1	$1.6	$2.1	$1.9
Amortization of individually insignificant unproved properties	0.1	2.8	0.1	5.3
Impairment of crude oil and natural gas properties	1.2	4.4	2.2	7.2
Land and buildings	3.0	—	3.0	—
Impairment of properties and equipment	$4.2	$4.4	$5.2	$7.2

Impairment of proved and unproved properties. Amounts represent the write-down of certain capitalized well costs on our properties as the expected development date for these locations are beyond the limits of the SEC five-year rule. 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. Amounts relate to insignificant leases that were subject to amortization. The decreases in amortization during the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015, were due to an impairment in the third quarter of 2015 that significantly reduced the carrying value of our Utica Shale leases.

Land and buildings. The impairment charge represents the excess of the carrying value over the estimated fair value, less the cost to sell, of a field operating facility in Greeley, Colorado, and 12 acres of land located adjacent to our Bridgeport, West Virginia, regional headquarters. The fair values of these assets were determined based upon estimated future cash flows from unrelated third-party bids, a Level 3 input.

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General and Administrative Expense

General and administrative expense increased $2.9 million to $23.6 million for the three months ended June 30, 2016 compared to $20.7 million for the three months ended June 30, 2015. The increase was primarily attributable to a $2.7 million increase in payroll and employee benefits, of which $1.3 million was stock-based compensation.

General and administrative expense increased $4.6 million to $46.4 million for the six months ended June 30, 2016 compared to $41.8 million for the six months ended June 30, 2015. The increase was primarily attributable to a $3.3 million increase in payroll and employee benefits, of which $1.6 million was stock-based compensation, a $0.7 million increase in costs for consulting and other professional services and a $0.4 million increase in marketing and government relations activities.

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 $106.1 million and $202.4 million for the three and six months ended June 30, 2016 compared to $69.0 million and $123.7 million for the three and six months ended June 30, 2015. The period-over-period change in DD&A expense related to crude oil and natural gas properties was primarily due to the following:

	June 30, 2016	
	Three Months Ended	Six Months Ended
	(in millions)	
Increase in production	$39.0	$ 72.8
Increase (decrease) in weighted-average depreciation, depletion and amortization rates	(1.9)	5.9
Total increase in DD&A expense related to crude oil and natural gas properties	$37.1	$ 78.7

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

	Three Months Ended June 30,		Six Months Ended June 30,	
Operating Region/Area	2016	2015	2016	2015
	(per Boe)			
Wattenberg Field	$20.73	$21.09	$21.19	$20.50
Utica Shale	13.84	14.23	11.16	12.27
Total weighted-average	20.41	20.48	20.72	19.76

The weighted-average DD&A expense rates for the three and six months ended June 30, 2016 were comparable to the three and six months ended June 30, 2015.

Non-crude oil and natural gas properties. Depreciation expense for non-crude oil and natural gas properties was $0.9 million and $2.0 million for the three and six months ended June 30, 2016, respectively, compared to $1.1 million and $2.2 million for the three and six months ended June 30, 2015, respectively.

Provision for Uncollectible Notes Receivable

A provision for uncollectible notes receivable of $44.7 million was recorded during the six months ended June 30, 2016 to impair two third-party notes receivable whose collection is not reasonably assured. See Note 3, Fair Value of Financial Instruments - Notes Receivable, to our condensed consolidated financial statements included elsewhere in this report for additional information.

Interest Expense

Interest expense decreased $0.9 million and $0.7 million during the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015. The decreases were primarily attributable to decreases in interest on the Convertible Notes as they matured in May 2016.

Interest Income

Interest income decreased $1.0 million and $0.5 million during the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015, as we ceased recognizing non-cash interest income on two third-party notes receivable.

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Provision for Income Taxes

See Note 6, Income Taxes, to the accompanying condensed consolidated financial statements included elsewhere in this report for a discussion of the changes in our effective tax rate for the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015. The effective tax rate of 37.9% and 37.5% benefit on loss for the three and six months ended June 30, 2016, respectively, is 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 pre-tax loss resulting in a tax benefit for the period. 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.

Net deferred income tax liability at June 30, 2016 decreased $102.3 million compared to December 31, 2015. This decrease is primarily attributable to the significant positive net settlements from derivatives during the six months ended June 30, 2016 and the significant negative net change in fair value of unsettled derivatives held at June 30, 2016.

Net Loss/Adjusted Net Income (Loss)

Net loss for the three and six months ended June 30, 2016 was $95.5 million and $167.0 million compared to net loss of $46.9 million and $29.8 million for the three and six months ended June 30, 2015. Adjusted net loss, a non-U.S. GAAP financial measure, was $5.1 million and $41.9 million for the three and six months ended June 30, 2016 compared to adjusted net income of $10.8 million and $17.9 million for the same prior year periods. The quarter-over-quarter changes in net loss are discussed above, with the most significant changes related to the decrease in commodity price risk management activity income and the increase in crude oil, natural gas and NGLs sales and DD&A expense. The year-over-year changes in net loss are discussed above, with the most significant changes related to the decrease in commodity price risk management activity income and the increase in crude oil, natural gas and NGLs sales, DD&A expense and provision for uncollectible notes receivable. These changes similarly impacted adjusted net income (loss), with the exception of the tax effected net change in fair value of unsettled derivatives. 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 six months ended June 30, 2016, our primary sources of liquidity were the net proceeds received from the March 2016 public offering of our common stock of $296.6 million and net cash flows from operating activities of $197.8 million. We used a portion of the net proceeds of the offering to repay all amounts then outstanding on our revolving credit facility, the principal amounts owed upon the maturity of the Convertible Notes in May 2016, and retained the remainder for general corporate purposes.

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 derivative instruments. 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. 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 2016 cash flows from operations. As of June 30, 2016, the fair value of our derivatives was a net asset of $61.9 million. Based on the forward pricing strip at June 30, 2016, we would expect positive net settlements totaling approximately $75.9 million during the second half of 2016. However, based upon our current hedge position and assuming current strip pricing, during periods subsequent to 2016 our derivatives may no longer be a significant source of cash flow, and may result in cash outflows. For the six months ended June 30, 2016 and 2015, net settled derivatives comprised approximately 61% and 65%, respectively, of our cash flows from operating activities. See Part I, Item 3, Quantitative and Qualitative Disclosures about Market Risk, included elsewhere in this report for additional information regarding our derivatives positions by year of maturity.

Our working capital fluctuates for various reasons, including, but not limited to, changes in the fair value of our commodity derivative instruments and changes in our cash and cash equivalents due to our practice of utilizing excess cash to reduce the outstanding borrowings under our revolving credit facility. At June 30, 2016, we had working capital of $131.9 million compared to $30.7 million at December 31, 2015. The increase in working capital as of June 30, 2016 is primarily the result of an increase in cash and cash equivalents and the repayment of the Convertible Notes in May 2016, offset in part by a decrease in the fair value of unsettled derivatives.

In recent periods, including the first half of 2016, we have been able to access borrowings under our revolving credit facility and to obtain proceeds from the issuance of securities. We ended June 2016 with cash and cash equivalents of $109.1 million and availability under our revolving credit facility of $438.3 million, for a total liquidity position of $547.4 million, compared to $402.2 million at December 31, 2015. These amounts exclude an additional $250 million available under our revolving credit facility, subject to certain terms and conditions of the credit agreement. The increase in liquidity of $145.2 million, or 36.1%, during the six months ended June 30, 2016 was primarily attributable to net cash flows from operating activities of $197.8 million and net cash flows from financing activities of $141.3 million, primarily due to the

March 2016 public offering of our common stock, offset in part by cash paid for capital expenditures of $235.7 million. Our liquidity position was reduced by the cash payment of approximately $115 million upon the maturity of our Convertible Notes in May 2016. With our current derivative position, liquidity position and expected cash flows from operations, we believe that we have sufficient capital to fund our planned drilling operations for the next 12 months. We cannot, however, assure sources of capital available to us in the past will be available to us in the future.

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 $50.73 per share and approximately six million shares of our common stock in March 2016 in an underwritten public offering at a price to us of $50.11 per share.

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 May 2016, we completed the semi-annual redetermination of our revolving credit facility by the lenders, which resulted in the reaffirmation of our borrowing base at $700 million. However, we elected to maintain the aggregate commitment level at $450 million. The maturity date of the revolving credit facility is May 2020. We had no outstanding balance on our revolving credit facility as of June 30, 2016. 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 June 30, 2016, we were in compliance with all debt covenants with a 1.0 times debt to EBITDAX ratio and a 4.0 to 1.0 current ratio. We expect to remain in compliance throughout the next year.

The indenture governing our 7.75% senior notes due 2022 contains customary restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (a) incur additional debt, (b) make certain investments or pay dividends or distributions on our capital stock or purchase, redeem or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) restrict the payment of dividends or other payments by restricted subsidiaries to us, (e) create liens that secure debt, (f) enter into transactions with affiliates and (g) merge or consolidate with another company. At June 30, 2016, we were in compliance with all covenants and expect to remain in compliance throughout the next year.

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

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 $51.3 million for the six months ended June 30, 2016 compared to the six months ended June 30, 2015, primarily due to increases in net settlements from our derivative positions of $25.7 million and crude oil, natural gas and NGLs sales of $15.2 million and the increase in changes in assets and liabilities of $18.6 million related to the timing of cash payments and receipts. These increases were offset in part by the increase in transportation, gathering and processing expenses of $5.9 million. The key components for the changes in our cash flows provided by operating activities are described in more detail in Results of Operations above.

Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased $32.8 million during the six months ended June 30, 2016, compared to the six months ended June 30, 2015. The increase was primarily due to the same factors mentioned above for changes in cash flows provided by operating activities, without regard to timing of cash payments and receipts of assets and liabilities. Adjusted EBITDA, a non-U.S. GAAP financial measure, decreased by $16.3 million during the six months ended June 30, 2016 compared to the six months ended June 30, 2015. The decrease was primarily the result of recording a provision for uncollectible notes receivable of $44.7 million and the increase in transportation, gathering and processing expenses of $5.9 million and general and administrative expense of $4.6 million, offset in part by increases in net settlements from our derivative positions of $25.7 million and crude oil, natural gas and NGLs sales of $15.2 million. See Reconciliation of Non-U.S. GAAP Financial Measures, below, for a more detailed discussion of non-U.S. GAAP financial measures.

Investing Activities. Because crude oil and natural gas production from a well declines rapidly in the first few years of production, we need to continue to commit significant amounts of capital in order to maintain and grow our production and replace our reserves. If capital is not available or is constrained in the future, we will be limited to our cash flows from operations and liquidity under our revolving credit facility as the sources for funding our capital expenditures.

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. Net cash used in investing activities of $230.8 million during the six months ended June 30, 2016 was primarily related to cash utilized for our drilling operations, including completion activities. For the full year 2016, we expect that our cash flows from operations will approximate our cash flows from investing activities.

Financing Activities. Net cash from financing activities for the six months ended June 30, 2016 decreased by approximately $55.5 million compared to the six months ended June 30, 2015. Net cash from financing activities of $141.3 million for the six months ended June 30, 2016 was primarily related to the $296.6 million received from the issuance of our common stock in March 2016, partially offset by the $115.0 million payment of principal amounts owed upon the maturity of the Convertible Notes and net payments of approximately $37.0 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 June 30,						Six Months Ended June 30,					
	2016			2015			2016			2015		
Operating Region/Area	Productive	In-Process	Dry (1)	Productive	In-Process	Dry (1)	Productive	In-Process	Dry (1)	Productive	In-Process	Dry (1)
Development Wells												
Wattenberg Field, operated wells	27.7	47.2	0.4	35.4	45.9	1.0	52.6	47.2	0.4	48.5	45.9	1.0
Wattenberg Field, non-operated wells	1.7	7.7	—	1.6	4.9	—	3.2	7.7	—	4.2	4.9	—
Utica Shale	2.8	1.7	—	3.0	—	—	2.8	1.7	—	3.0	—	—
Total drilling activity	32.2	56.6	0.4	40.0	50.8	1.0	58.6	56.6	0.4	55.7	50.8	1.0

(1) Represents mechanical failures that resulted in the plugging and abandonment of the respective wells.

Off-Balance Sheet Arrangements

At June 30, 2016, 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 2015 Form 10-K filed with the SEC on February 22, 2016.

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

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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 properties and equipment, depreciation, depletion and amortization expense and accretion of asset retirement obligations, less gain on commodity derivatives and net settlements on commodity derivatives. Adjusted EBITDA is not a measure of financial performance or liquidity under U.S. GAAP and should be considered in addition to, not as a substitute for, net income (loss), and should not be considered an indicator of cash flows reported in accordance with U.S. GAAP. Adjusted EBITDA includes certain non-cash costs incurred by the Company and does not take into account changes in operating assets and liabilities. Other companies in our industry may calculate adjusted EBITDA differently than we do, limiting its usefulness as a comparative measure. We believe adjusted EBITDA is relevant because it is a measure of our operational and financial performance, as well as a measure of our liquidity, and is used by our management, investors, commercial banks, research analysts and others to analyze such things as:

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in millions)			
Adjusted cash flows from operations:				
Adjusted cash flows from operations	$112.6	$96.9	$203.6	$170.8
Changes in assets and liabilities	(16.0)	(32.3)	(5.8)	(24.3)
Net cash from operating activities	$96.6	$64.6	$197.8	$146.5
Adjusted net income (loss):				
Adjusted net income (loss)	$(5.1)	$10.8	$(41.9)	$17.9
Gain (loss) on commodity derivative instruments	(92.7)	(49.0)	(81.7)	17.6
Net settlements on commodity derivative instruments	(53.3)	(44.1)	(120.2)	(94.5)
Tax effect of above adjustments	55.6	35.4	76.8	29.2
Net loss	$(95.5)	$(46.9)	$(167.0)	$(29.8)
Adjusted EBITDA to net loss:				
Adjusted EBITDA	$115.7	$102.6	$168.7	$185.0
Gain (loss) on commodity derivative instruments	(92.7)	(49.0)	(81.7)	17.6
Net settlements on commodity derivative instruments	(53.3)	(44.1)	(120.2)	(94.5)
Interest expense, net	(10.5)	(10.4)	(20.8)	(21.1)
Income tax provision	58.3	30.1	100.2	19.4
Impairment of properties and equipment	(4.2)	(4.4)	(5.2)	(7.2)
Depreciation, depletion and amortization	(107.0)	(70.1)	(204.4)	(125.9)
Accretion of asset retirement obligations	(1.8)	(1.6)	(3.6)	(3.1)
Net loss	$(95.5)	$(46.9)	$(167.0)	$(29.8)
Adjusted EBITDA to net cash from operating activities:				
Adjusted EBITDA	$115.7	$102.6	$168.7	$185.0
Interest expense, net	(10.5)	(10.4)	(20.8)	(21.1)
Stock-based compensation	6.4	5.1	11.1	9.5
Amortization of debt discount and issuance costs	1.3	1.8	3.1	3.5
(Gain) loss on sale of properties and equipment	0.3	(0.2)	0.2	(0.2)
Other	(0.6)	(2.0)	41.3	(5.9)
Changes in assets and liabilities	(16.0)	(32.3)	(5.8)	(24.3)
Net cash from operating activities	$96.6	$64.6	$197.8	$146.5

Regulatory Update

In May 2016, the EPA issued a draft Information Collection Request that will impact all known operators in the U.S. and which is aimed at regulating existing onshore oil and gas sources. The EPA also finalized a rule regarding source determination and permitting requirements for the onshore oil and gas industry under the Clean Air Act. Under this final rule, our operations could be subject to increased permitting costs and more stringent control requirements. In June 2016, the EPA published amendments to the 2012 NSPS OOOO rules focused on achieving additional methane and volatile organic compound reductions from the oil and natural gas industry. The EPA also finalized pretreatment standards for the discharge of wastewater to publicly-owned treatment works for the onshore oil and gas extraction industry. Other agencies have also published new proposed or final rules impacting the onshore oil and gas industry. For example, the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration issued an additional notice of proposed rulemaking in June 2016 related to the safety of transmission and gathering lines. In addition, in March 2016, the U.S. Fish and Wildlife Service finalized a rule to alter how it identifies critical habitat for endangered and threatened species, which could expand the reach of the Endangered Species Act depending on how it is implemented.

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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 have a fixed rate and, therefore, near-term changes in interest rates do not expose us to risk of earnings or cash flow loss; however, near-term changes in interest rates may affect the fair value of our fixed-rate debt.

As of June 30, 2016, our interest-bearing deposit accounts included money market accounts, certificates of deposit and checking and savings accounts with various banks. The amount of our interest-bearing cash, cash equivalents and restricted cash as of June 30, 2016 was $90.2 million with a weighted-average interest rate of 0.3%. Based on a sensitivity analysis of our interest-bearing deposits as of June 30, 2016, we estimate that a 1% increase in interest rates would increase interest income for the six months ended June 30, 2016 by approximately $0.5 million.

As of June 30, 2016, we had no outstanding balance on our revolving credit facility.

Commodity Price Risk

We are exposed to the potential risk of loss from adverse changes in the market price of crude oil, natural gas and NGLs. Pursuant to established policies and procedures, we manage a portion of the risks associated with these market fluctuations using derivative instruments. These instruments help us predict with greater certainty the effective crude oil and natural gas prices we will receive for our hedged production. We believe that our derivative policies and procedures are effective in achieving our risk management objectives.

The following table presents our derivative positions related to crude oil and natural gas sales in effect as of June 30, 2016:

	Collars			Fixed-Price Swaps		Basis Protection Swaps		
Commodity/ Index/ Maturity Period	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted-Average Contract Price Floors	Ceilings	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted-Average Contract Price	Quantity (BBtu) (1)	Weighted-Average Contract Price	Fair Value June 30, 2016 (2) (in millions)
Natural Gas								
NYMEX								
2016	2,280.0	$ 3.80	$ 4.12	15,410.0	$ 3.66	13,806.5	$ (0.29)	$ 10.6
2017	7,920.0	3.59	4.13	27,290.0	3.55	12,000.0	(0.28)	13.6
2018	1,230.0	3.00	3.67	17,430.0	3.00	—	—	(0.1)
Total Natural Gas	11,430.0			60,130.0		25,806.5		24.1

Crude Oil								
NYMEX								
2016	870.0	77.59	97.55	1,860.0	72.21	—	—	65.3
2017	1,464.0	49.22	65.95	3,004.0	44.92	—	—	(17.4)
2018	1,512.0	41.85	54.31	504.0	47.08	—	—	(10.1)
Total Crude Oil	3,846.0			5,368.0		—		37.8
Total Natural Gas and Crude Oil								$ 61.9

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

(2) Approximately 33.1% of the fair value of our derivative assets and 19.2% of the fair value of our derivative liabilities were measured using significant unobservable inputs (Level 3). See Note 3, Fair Value Measurements, to the condensed consolidated financial statements included elsewhere in this report.

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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 June 30, 2016	Six Months Ended June 30, 2016	Year Ended December 31, 2015
Average Index Closing Price:			
Crude oil (per Bbl)			
NYMEX	$ 45.59	$ 39.52	$ 48.80
Natural gas (per MMBtu)			
NYMEX	$ 1.95	$ 2.02	$ 2.66
CIG	1.67	1.73	2.44
TETCO M-2 (1)	1.27	1.23	1.49
Average Sales Price Realized:			
Excluding net settlements on derivatives			
Crude oil (per Bbl)	$ 40.37	$ 34.46	$ 40.14
Natural gas (per Mcf)	1.37	1.38	2.04
NGLs (per Bbl)	11.93	9.89	10.72

(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 June 30, 2016, we estimate 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 $63.0 million, whereas a 10% decrease in prices would have resulted in an increase in fair value of $63.0 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 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 counterparty’s 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 natural gas prices continue to remain depressed, certain third-party producers under our Gas Marketing segment have begun and continue to experience financial distress, which has led to certain contractual defaults and litigation; however, to date, we have had no material counterparty default losses. We have initiated several legal actions for breach of contract, collection and related claims against certain third-party producers that are delinquent in their payment obligations, which have to date resulted in one default judgment. There have been no collections received to date and and some of the third-party producers have shut-in their wells and we expect this trend to continue for this segment.

A group of independent West Virginia natural gas producers has filed, but not served on RNG, a complaint in Marshall County, West Virginia, naming Dominion, certain entities affiliated with Dominion, and RNG as defendants, alleging various contractual, fiduciary and related claims against the defendants, all of which are associated with firm transportation contracts entered into by plaintiffs and relating to pipelines owned and operated by Dominion and its affiliates. At this time, RNG is unable to estimate any potential damages associated with the claims, but believes the complaint is without merit and intends to vigorously pursue its defense.

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.

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Disclosure of Limitations

Because the information above included only those exposures that existed at June 30, 2016, it does not consider those exposures or positions which could arise after that date. As a result, our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, our commodity price risk management strategies at the time, and interest rates and commodity prices at the time.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of June 30, 2016, we carried out an evaluation under the supervision and with the participation of management, including the Chief Executive Officer and the Principal 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 Principal Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2016.

Changes in Internal Control over Financial Reporting

During the three months ended June 30, 2016, 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 2015 Form 10-K. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

There have been no material changes from the risk factors previously disclosed in our 2015 Form 10-K, except for the following:

Ballot initiatives have been proposed in Colorado that would impose draconian limitations on statewide oil and gas development activities or could result in vastly expanded authority of local governments to regulate or prohibit oil and natural gas production and development in their jurisdictions. Proponents of two such initiatives have submitted signatures in an effort to qualify the initiatives to appear on the ballot in November 2016. Either of these proposals could result in an effective ban on new development operations in areas where we have significant leasehold and existing production, and one of these proposals might affect production from existing wells. If either initiative is implemented and survives legal challenge, it would have a severe impact on our development plans and on our results of operations, financial condition and reserves. Future initiatives, legislation or regulations may be adopted with similar effects.

As previously disclosed, certain interest groups in Colorado opposed to oil and natural gas development generally, and hydraulic fracturing in particular, have advanced various alternatives for ballot initiatives which would result in significantly limiting or preventing oil and natural gas development in the state. Proponents of two such initiatives have submitted signatures in an effort to qualify the initiatives to appear on the ballot in November 2016. The signatures are subject to a verification process to be conducted by the Colorado Secretary of State. This process could take up to 30 days. We do not know what the outcome of this process will be. If approved by the voters of Colorado, the proposals will take effect by the end of 2016.

One of the initiatives, which we refer to as the “local control” initiative, would amend the state constitution to give city, town and county governments the right to regulate, or to ban, oil and gas development and production within their boundaries, notwithstanding rules and approvals to the contrary at the state level. If implemented, this amendment could result in our operations being subject to a variety of different, and possibly inconsistent, requirements in numerous different jurisdictions within the state of Colorado, and could prohibit exploration, development and production altogether in some or all of these jurisdictions. This would likely materially increase our costs and make our operations less efficient, and it could prevent us from developing and producing significant properties.

The other initiative, which we refer to as the “setback” initiative, would amend the state constitution to require all new oil and gas development facilities to be located at least 2,500 feet away from any occupied structure or “area of special concern,” broadly defined to include public and community drinking water sources, lakes, rivers, perennial or intermittent streams, creeks, irrigation canals, riparian areas, playgrounds, permanent sports fields, amphitheaters, public parks and public open space. The current minimum required setback between oil and gas wells and occupied structures is generally 500 feet. The Colorado Oil and Gas Conservation Commission has estimated that implementation of the

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proposed initiative would make drilling unlawful on approximately 90% of the surface area of the state of Colorado, and approximately 85% of the surface area of Weld County. If passed, this proposal would effectively prohibit the vast majority of our planned future drilling activities, and would therefore make it impossible to continue to pursue our current development plans. This would have a highly material and adverse effect on our results of operations, financial condition and reserves.

Because substantially all of our current operations and reserves are located in Colorado, the risks we face with respect to these proposals, and possible similar future proposals, are greater than those of our competitors with more geographically diverse operations. We cannot predict the outcome of the potentially pending initiatives or possible future regulatory developments.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share
April 1 - 30, 2016	41,911	$ 59.59
May 1 - 31, 2016	—	—
June 1 - 30, 2016	6,595	57.61
Total second quarter purchases	48,506	59.32

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

ITEM 3. DEFAULTS UPON SENIOR SECURITIES - None.

ITEM 4. MINE SAFETY DISCLOSURES - Not applicable.

ITEM 5. OTHER INFORMATION - None.

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ITEM 6. EXHIBITS

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
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 Principal 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 Principal Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.					
101.INS	XBRL Instance Document					X
101.SCH	XBRL Taxonomy Extension Schema Document					X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document					X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document					X
101.LAB	XBRL Taxonomy Extension Label Linkbase Document					X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document					X

*Management contract or compensatory arrangement.
** Furnished herewith.

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PDC ENERGY, INC.

SIGNATURES

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

PDC Energy, Inc.
(Registrant)

Date: August 9, 2016 /s/ Barton R. Brookman
Barton R. Brookman
President and Chief Executive Officer
(principal executive officer)

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