UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2015

OR

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

For the transition period from to

Commission File Number 001-35410

Matador Resources Company
(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	27-4662601 (I.R.S. Employer Identification No.)
5400 LBJ Freeway, Suite 1500 Dallas, Texas (Address of principal executive offices)	75240 (Zip Code)

(972) 371-5200
(Registrant's telephone number, including area code)

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. x Yes ¨ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, 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). x Yes ¨ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the 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	¨
Non-accelerated filer	¨ (Do not check if a smaller reporting company)	Smaller reporting company	¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ¨ Yes x No

As of November 4, 2015, there were 85,557,957 shares of the registrant’s common stock, par value $0.01 per share, outstanding.

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FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 2015
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Part I – FINANCIAL INFORMATION
Item 1. Financial Statements
Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED BALANCE SHEETS - UNAUDITED
(In thousands, except par value and share data)

	September 30, 2015	December 31, 2014
ASSETS		
Current assets		
Cash	$ 13,887	$ 8,407
Restricted cash	450	609
Accounts receivable		
Oil and natural gas revenues	23,743	28,976
Joint interest billings	13,361	6,925
Other	9,426	9,091
Derivative instruments	28,165	55,549
Assets held for sale	32,413	—
Lease and well equipment inventory	2,106	1,212
Prepaid expenses	2,989	1,649
Total current assets	126,540	112,418
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	2,018,241	1,617,913
Unproved and unevaluated	392,299	264,419
Other property and equipment	60,589	43,472
Less accumulated depletion, depreciation and amortization	(1,329,082)	(603,732)
Net property and equipment	1,142,047	1,322,072
Other assets		
Derivative instruments	2,028	—
Deferred income taxes	9,676	—
Other assets	231	—
Total other assets	11,935	—
Total assets	$ 1,280,522	$ 1,434,490
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current liabilities		
Accounts payable	$ 16,012	$ 17,526
Accrued liabilities	102,327	109,502
Royalties payable	21,737	14,461
Advances from joint interest owners	306	—
Amounts due to Joint Ventures	2,250	—
Deferred income taxes	10,426	19,751
Income taxes payable	—	444
Other current liabilities	223	103
Total current liabilities	153,281	161,787
Long-term liabilities		
Borrowings under Credit Agreement	—	338,199
Senior unsecured notes payable	390,959	—
Asset retirement obligations	13,413	11,640
Amounts due to Joint Ventures	4,500	—

Deferred income taxes	—	53,783
Other long-term liabilities	1,765	2,540
Total long-term liabilities	410,637	406,162
Commitments and contingencies (Note 11)		
Shareholders' equity		
Common stock - $0.01 par value, 120,000,000 and 80,000,000 shares authorized; 85,687,475 and 73,373,744 shares issued; and 85,520,957 and 73,342,777 shares outstanding, respectively	857	734
Additional paid-in capital	1,023,425	724,819
Retained (deficit) earnings	(308,529)	140,855
Total Matador Resources Company shareholders' equity	715,753	866,408
Non-controlling interest in subsidiary	851	133
Total shareholders' equity	716,604	866,541
Total liabilities and shareholders' equity	$ 1,280,522	$ 1,434,490

The accompanying notes are an integral part of these financial statements.

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Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS - UNAUDITED
(In thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Revenues				
Oil and natural gas revenues	$71,815	$96,617	$222,128	$274,605
Realized gain (loss) on derivatives	19,862	(701)	52,146	(5,458)
Unrealized gain (loss) on derivatives	6,733	16,293	(25,356)	7,950
Total revenues	98,410	112,209	248,918	277,097
Expenses				
Production taxes and marketing	9,291	8,617	26,598	23,739
Lease operating	14,917	13,691	42,912	34,747
Depletion, depreciation and amortization	45,237	35,143	143,477	90,970
Accretion of asset retirement obligations	182	130	427	371
Full-cost ceiling impairment	285,721	—	581,874	—
General and administrative	12,151	8,099	38,523	23,417
Total expenses	367,499	65,680	833,811	173,244
Operating (loss) income	(269,089)	46,529	(584,893)	103,853
Other income (expense)				
Net loss on asset sales and inventory impairment	—	—	(97)	—
Interest expense	(7,229)	(673)	(15,168)	(3,685)
Interest and other income	999	267	1,885	715
Total other expense	(6,230)	(406)	(13,380)	(2,970)
(Loss) income before income taxes	(275,319)	46,123	(598,273)	100,883
Income tax (benefit) provision				
Current	(295)	(156)	(295)	2,658
Deferred	(33,010)	16,660	(148,750)	34,017
Total income tax (benefit) provision	(33,305)	16,504	(149,045)	36,675
Net (loss) income	(242,014)	29,619	(449,228)	64,208
Net income attributable to non-controlling interest in subsidiary	(45)	—	(156)	—
Net (loss) income attributable to Matador Resources Company shareholders	$(242,059)	$29,619	$(449,384)	$64,208
Earnings (loss) per common share				
Basic	$(2.86)	$0.40	$(5.58)	$0.93
Diluted	$(2.86)	$0.40	$(5.58)	$0.92
Weighted average common shares outstanding				
Basic	84,685	73,341	80,481	69,185
Diluted	84,685	74,028	80,481	69,879

The accompanying notes are an integral part of these financial statements.

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Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY - UNAUDITED
(In thousands)
For the Nine Months Ended September 30, 2015

	Common Stock Shares	Common Stock Amount	Preferred Stock Shares	Preferred Stock Amount	Additional paid-in capital	Retained earnings (deficit)	Treasury Stock Shares	Treasury Stock Amount	Total shareholders' equity attributable to Matador Resources Company	Non-controlling interest in subsidiary	Total shareholders' equity
Balance at January 1, 2015	73,374	$734	—	$—	$724,819	$140,855	31	$—	$866,408	$133	$866,541
Issuance of common stock	10,329	104	—	—	260,148	—	—	—	260,252	—	260,252
Issuance of preferred stock	—	—	150	1	32,489	—	—	—	32,490	—	32,490
Cost to issue equity	—	—	—	—	(1,151)	—	—	—	(1,151)	—	(1,151)
Conversion of preferred stock to common stock	1,500	15	(150)	(1)	(14)	—	—	—	—	—	—
Stock-based compensation expense related to equity-based awards	—	—	—	—	6,660	—	—	—	6,660	—	6,660
Stock options exercised	25	—	—	—	10	—	—	—	10	—	10
Liability-based stock option awards settled	15	—	—	—	467	—	—	—	467	—	467
Restricted stock issued	392	4	—	—	(4)	—	—	—	—	—	—
Restricted stock forfeited	—	—	—	—	—	—	136	—	—	—	—
Vesting of restricted stock units	52	—	—	—	1	—	—	—	1	—	1
Capital contribution from non-controlling interest owners in less-than-wholly-owned subsidiary	—	—	—	—	—	—	—	—	—	600	600
Distribution to non-controlling interest owners of less-than-wholly-owned subsidiary	—	—	—	—	—	—	—	—	—	(38)	(38)
Current period net (loss) income	—	—	—	—	—	(449,384)	—	—	(449,384)	156	(449,228)
Balance at September 30, 2015	85,687	$857	—	$—	$1,023,425	$(308,529)	167	$—	$715,753	$851	$716,604

The accompanying notes are an integral part of these financial statements.
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Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS - UNAUDITED
(In thousands)

	Nine Months Ended September 30,	
	2015	2014
Operating activities		
Net (loss) income	$(449,228)	$64,208
Adjustments to reconcile net (loss) income to net cash provided by operating activities		
Unrealized loss (gain) on derivatives	25,356	(7,950)
Depletion, depreciation and amortization	143,477	90,970
Accretion of asset retirement obligations	427	371
Full-cost ceiling impairment	581,874	—
Stock-based compensation expense	6,886	4,665
Deferred income tax (benefit) provision	(148,750)	34,017
Amortization of debt issuance cost (non-cash interest expense)	551	—
Net loss on asset sales and inventory impairment	97	—
Changes in operating assets and liabilities		
Accounts receivable	1,997	(12,605)
Lease and well equipment inventory	(225)	(193)
Prepaid expenses	(329)	(74)
Other assets	665	(810)
Accounts payable, accrued liabilities and other current liabilities	16,863	(820)
Royalties payable	6,898	6,175
Advances from joint interest owners	306	—
Income taxes payable	(444)	2,565
Other long-term liabilities	(497)	(160)
Net cash provided by operating activities	185,924	180,359
Investing activities		
Oil and natural gas properties capital expenditures	(334,951)	(407,023)
Expenditures for other property and equipment	(46,738)	(2,906)
Business combination, net of cash acquired	(24,028)	—
Restricted cash in less-than-wholly-owned subsidiaries	158	—
Net cash used in investing activities	(405,559)	(409,929)
Financing activities		
Repayments of borrowings	(476,982)	(180,000)
Borrowings under Credit Agreement	125,000	230,000
Proceeds from issuance of senior unsecured notes	400,000	—
Cost to issue senior unsecured notes	(9,479)	—
Proceeds from issuance of common stock	188,720	181,875
Cost to issue equity	(1,151)	(590)
Proceeds from stock options exercised	10	6
Capital contribution from non-controlling interest owners in less-than-wholly-owned subsidiary	600	—
Distributions to non-controlling interest owners of less-than-wholly-owned subsidiaries	(38)	—
Taxes paid related to net share settlement of stock-based compensation	(1,565)	(285)
Net cash provided by financing activities	225,115	231,006
Increase in cash	5,480	1,436
Cash at beginning of period	8,407	6,287

Cash at end of period	$13,887	$7,723

Supplemental disclosures of cash flow information (Note 12)

The accompanying notes are an integral part of these financial statements.

Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED

NOTE 1 - NATURE OF OPERATIONS

Matador Resources Company, a Texas corporation ("Matador" and, collectively with its subsidiaries, the "Company"), is an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. The Company's current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Permian (Delaware) Basin in Southeast New Mexico and West Texas and the Eagle Ford shale play in South Texas. The Company also operates in the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Interim Financial Statements, Basis of Presentation, Consolidation and Significant Estimates

The unaudited condensed consolidated financial statements of Matador and its subsidiaries have been prepared in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") but do not include all of the information and footnotes required by generally accepted accounting principles in the United States of America ("U.S. GAAP") for complete financial statements and should be read in conjunction with the Company's audited consolidated financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2014 filed with the SEC (the "Annual Report"). The Company consolidates certain subsidiaries that are less-than-wholly-owned and the net income and equity attributable to the non-controlling interest in these subsidiaries have been reported separately as required by Accounting Standards Codification ("ASC") 810. The Company proportionately consolidates certain joint ventures that are less-than-wholly-owned and are involved in oil and natural gas exploration. All intercompany accounts and transactions have been eliminated in consolidation. In management's opinion, these interim unaudited condensed consolidated financial statements include all adjustments, consisting only of normal, recurring adjustments which are necessary for a fair presentation of the Company's consolidated financial statements as of September 30, 2015. Amounts as of December 31, 2014 are derived from the audited consolidated financial statements in the Annual Report.

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates and assumptions may also affect disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The Company's interim unaudited condensed consolidated financial statements are based on a number of significant estimates, including accruals for oil and natural gas revenues, accrued assets and liabilities primarily related to oil and natural gas operations, stock-based compensation, valuation of derivative instruments and oil and natural gas reserves. The estimates of oil and natural gas reserves quantities and future net cash flows are the basis for the calculations of depletion and impairment of oil and natural gas properties, as well as estimates of asset retirement obligations and certain tax accruals. While the Company believes its estimates are reasonable, changes in facts and assumptions or the discovery of new information may result in revised estimates. Actual results could differ from these estimates.

Reclassifications

Certain reclassifications have been made to the 2014 financial statements in order to conform to the current year presentation. These reclassifications had no effect on previously reported results of operations, cash flows or retained earnings.

Change in Accounting Principle

The Company adopted Accounting Standards Update ("ASU") 2015-03, Interest - Imputation of Interest (Subtopic 935-30): Simplifying the Presentation of Debt Issuance Costs, effective June 30, 2015. This standard requires companies that have historically presented debt issuance costs as an asset to present those costs as a direct deduction from the carrying amount of the underlying debt liability. To the extent that there are no borrowings under the Credit Agreement (as defined below), the related deferred loan costs will continue to be classified as an asset. The guidance required retrospective application in the financial statements. As such, the Company reclassified $1.8 million at

December 31, 2014 related to deferred loan costs for the Credit Agreement which had previously been presented in Prepaid Expenses and Other Assets. As the Company had no borrowings outstanding under the Credit Agreement at September 30, 2015, approximately $1.1 million of deferred loan costs related to the Credit Agreement are included in Prepaid Expenses and Other Assets. The Company's senior unsecured notes are presented net of approximately $9.0 million of deferred loan costs at September 30, 2015. The Company had no senior unsecured notes outstanding at December 31, 2014.

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Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

Restricted Cash
Restricted cash represents the cash held by our less-than-wholly-owned subsidiaries. By contractual agreement, the cash in these accounts is not to be commingled with other Company cash and is to be used only to fund the capital expenditures and operations of these less-than-wholly-owned subsidiaries.
Property and Equipment
The Company uses the full-cost method of accounting for its investments in oil and natural gas properties. Under this method of accounting, all costs associated with the acquisition, exploration and development of oil and natural gas properties and reserves, including unproved and unevaluated property costs, are capitalized as incurred and accumulated in a single cost center representing the Company’s activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, capitalized interest on qualifying projects and certain general and administrative expenses directly related to acquisition, exploration and development activities, but do not include any costs related to production, selling or general corporate administrative activities. The Company capitalized approximately $1.4 million and $1.5 million of its general and administrative costs for the three months ended September 30, 2015 and 2014, respectively, and approximately $0.5 million and $0.8 million of its interest expense for the three months ended September 30, 2015 and 2014, respectively. The Company capitalized approximately $4.9 million and $4.3 million of its general and administrative costs for the nine months ended September 30, 2015 and 2014, respectively, and approximately $2.9 million and $2.2 million of its interest expense for the nine months ended September 30, 2015 and 2014, respectively.
The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized costs less related deferred income taxes or the cost center “ceiling.” The cost center ceiling is defined as the sum of:
(a) the present value, discounted at 10%, of future net revenues of proved oil and natural gas reserves, reduced by the estimated costs of developing these reserves, plus
(b) unproved and unevaluated property costs not being amortized, plus
(c) the lower of cost or estimated fair value of unproved and unevaluated properties included in the costs being amortized, if any, less
(d) income tax effects related to the properties involved.
Any excess of the Company’s net capitalized costs above the cost center ceiling as described above is charged to operations as a full-cost ceiling impairment. The need for a full-cost ceiling impairment is required to be assessed on a quarterly basis. The fair value of the Company’s derivative instruments is not included in the ceiling test computation as the Company does not designate these instruments as hedge instruments for accounting purposes.
The estimated present value of after-tax future net cash flows from proved oil and natural gas reserves is highly dependent upon the quantities of proved reserves, the estimation of which requires substantial judgment. The associated commodity prices and applicable discount rate used in these estimates are in accordance with guidelines established by the SEC. Under these guidelines, oil and natural gas reserves are estimated using then-current operating and economic conditions, with no provision for price and cost escalations in future periods except by contractual arrangements. Future net revenues are calculated using prices that represent the arithmetic averages of first-day-of-the-month oil and natural gas prices for the previous 12-month period, and the guidelines further dictate that a 10% discount factor be used to determine the present value of future net revenues. For the period from October 2014 through September 2015, these average oil and natural gas prices were $55.73 per barrel (“Bbl”) and $3.06 per million British thermal units (“MMBtu”), respectively. For the period from October 2013 through September 2014, these average oil and natural gas prices were $95.56 per Bbl and $4.24 per MMBtu, respectively. In estimating the present value of after-tax future net cash flows from proved oil and natural gas reserves, the average oil prices were adjusted by property for quality, transportation and marketing fees and regional price differentials, and the average

natural gas prices were adjusted by property for energy content, transportation and marketing fees and regional price differentials. At September 30, 2015 and 2014, the Company's oil and natural gas reserves estimates were prepared by the Company's engineering staff in accordance with guidelines established by the SEC and then audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

Using the average commodity prices, as adjusted, to determine the Company's estimated proved oil and natural gas reserves at September 30, 2015, the Company's net capitalized costs less related deferred income taxes exceeded the full-cost

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NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

ceiling by $252.4 million. As a result, the Company recorded an impairment charge of $285.7 million to its net capitalized costs and a deferred income tax credit of $33.3 million related to the full-cost ceiling limitation at September 30, 2015. At June 30, 2015, the Company's net capitalized costs less related deferred income taxes exceeded the full-cost ceiling by $146.3 million and thus the Company recorded an impairment charge of $229.0 million to its net capitalized costs and a deferred income tax credit of $82.7 million related to the full-cost ceiling limitation at June 30, 2015. At March 31, 2015, the Company's net capitalized costs less related deferred income taxes exceeded the full-cost ceiling by $42.8 million and thus the Company recorded an impairment charge of $67.1 million to its net capitalized costs and a deferred income tax credit of $24.3 million related to the full-cost ceiling limitation at March 31, 2015. These three quarterly impairment charges are reflected in the Company's unaudited condensed consolidated statement of operations for the nine months ended September 30, 2015. At September 30, 2014, the Company's net capitalized costs less related deferred income taxes did not exceed the full-cost ceiling and thus the Company recorded no impairment to its net capitalized costs for the three and nine months ended September 30, 2014. As a non-cash item, the full-cost ceiling impairment impacts the accumulated depletion and the net carrying value of the Company's assets on its consolidated balance sheet, as well as the corresponding consolidated shareholders' equity, but it has no impact on the Company's consolidated net cash flows as reported. Changes in oil and natural gas production rates, oil and natural gas prices, reserves estimates, future development costs and other factors will determine the Company's actual ceiling test computation and impairment analyses in future periods.

Capitalized costs of oil and natural gas properties are amortized using the unit-of-production method based upon production and estimates of proved reserves quantities. Unproved and unevaluated property costs are excluded from the amortization base used to determine depletion. Unproved and unevaluated properties are assessed for possible impairment on a periodic basis based upon changes in operating or economic conditions. This assessment includes consideration of the following factors, among others: the assignment of proved reserves, geological and geophysical evaluations, intent to drill, remaining lease term and drilling activity and results. Upon impairment, the costs of the unproved and unevaluated properties are immediately included in the amortization base. Exploratory dry holes are included in the amortization base immediately upon determination that the well is not productive.

Assets Held for Sale

On the date at which assets of the Company meet all the criteria required to be classified as held for sale, the Company discontinues the recording of depletion and depreciation of the assets or asset group to be sold and reclassifies the assets and related liabilities to be sold as held for sale on the accompanying consolidated balance sheets. The assets and liabilities are measured at the lower of their carrying amount or estimated fair value less cost to sell.

On October 1, 2015, the Company completed the sale of its wholly-owned subsidiary that owned certain natural gas gathering and processing assets in the Delaware Basin in Loving County, Texas (the "Loving County System") to a subsidiary of EnLink Midstream Partners, LP ("EnLink"). The Loving County System included a cryogenic natural gas processing plant with approximately 35 million cubic feet per day of inlet capacity (the "Processing Plant") and approximately six miles of high-pressure gathering pipeline which connects the Company's gathering system to the Processing Plant (see Note 15). At September 30, 2015, the Loving County System met all the criteria required to be classified as assets held for sale. The carrying values of the Loving County System assets were reclassified from property and equipment to assets held for sale in the accompanying consolidated balance sheet in the amount of $32.4 million. The Company retained all assets and all liabilities related to the Loving County System up to the closing date.

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Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

Allocation of Purchase Price in Business Combinations
As part of the Company's business strategy, it periodically pursues the acquisition of oil and natural gas properties. The purchase price in a business combination is allocated to the assets acquired and liabilities assumed based on their fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. The most significant estimates in the allocation typically relate to the value assigned to proved oil and natural gas reserves and unproved and unevaluated properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.
Earnings (Loss) Per Common Share
The Company reports basic earnings (loss) per common share, which excludes the effect of potentially dilutive securities, and diluted earnings per common share, which includes the effect of all potentially dilutive securities, unless their impact is anti-dilutive.
The following table sets forth the computation of diluted weighted average common shares outstanding for the three and nine months ended September 30, 2015 and 2014 (in thousands).

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Weighted average common shares outstanding				
Basic	84,685	73,341	80,481	69,185
Dilutive effect of options, restricted stock units and preferred shares	—	687	—	694
Diluted weighted average common shares outstanding	84,685	74,028	80,481	69,879

A total of 2.4 million options to purchase shares of the Company's common stock and 0.1 million restricted stock units were excluded from the calculations above for both the three and nine months ended September 30, 2015, respectively, and zero and 1.5 million preferred shares were excluded from the calculations above for the three and nine months ended September 30, 2015, respectively, because their effects were anti-dilutive. Additionally, 0.8 million restricted shares, which are participating securities, were excluded from the calculations above for both the three and nine months ended September 30, 2015, respectively, as the security holders do not have the obligation to share in the losses of the Company.
Recent Accounting Pronouncements
Revenue from Contracts with Customers. In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606), which specifies how and when to recognize revenue. In addition, this standard requires expanded disclosures surrounding revenue recognition and is intended to improve, and converge with international standards, the financial reporting requirements for revenue from contracts with customers. ASU 2014-09 will become effective for fiscal years beginning after December 15, 2017, i.e., in the Company's first fiscal quarter of 2018. The Company is currently evaluating the impact, if any, of the adoption of this ASU on its consolidated financial statements.
NOTE 3 – BUSINESS COMBINATION
On February 27, 2015, the Company completed a business combination with Harvey E. Yates Company ("HEYCO"), a subsidiary of HEYCO Energy Group, Inc., through a merger of HEYCO with and into a wholly-owned subsidiary of Matador (the "HEYCO Merger"). In the HEYCO Merger, the Company obtained certain oil and natural gas producing properties and undeveloped acreage located in Lea and Eddy Counties, New Mexico, consisting of approximately 58,600 gross (18,200 net) acres strategically located between the Company's existing acreage in its Ranger and Rustler

Breaks prospect areas. HEYCO, headquartered in Roswell, New Mexico, was privately-owned prior to the transaction. As consideration for the business combination, Matador paid approximately $33.6 million in cash and assumed debt obligations and issued 3,300,000 shares of Matador common stock and 150,000 shares of a new series of Matador Series A Convertible Preferred Stock (“Series A Preferred Stock”) to HEYCO Energy Group, Inc. (convertible into ten shares of common stock for each one share of Series A Preferred Stock upon the effectiveness of an amendment to the Company’s Amended and Restated Certificate of Formation to increase the number of authorized shares of common stock; the Series A Preferred Stock converted to common stock on April 6, NOTE 3 - BUSINESS COMBINATION - Continued

2015). Matador paid an additional $3.0 million for customary purchase price adjustments, including adjusting for production, revenues and operating and capital expenditures from September 1, 2014 to closing. As a result of the HEYCO Merger, Matador incurred deferred tax liabilities of approximately $76.0 million and assumed other liabilities of approximately $4.6 million. The HEYCO Merger was accounted for using the acquisition method under ASC Topic 805, "Business Combinations," which requires the assets acquired and liabilities assumed to be recorded at fair value as of the respective acquisition date. During the nine months ended September 30, 2015, the Company incurred approximately $2.5 million of transaction costs associated with the HEYCO Merger. The majority of the assets acquired in the HEYCO Merger were in the form of non-producing acreage. The producing wells acquired in the HEYCO Merger did not have a material impact on the Company's revenues or results of operations for the three and nine months ended September 30, 2015.
The preliminary allocation of the consideration given related to this business combination was as follows (in thousands).

Consideration given	Allocation
Cash	$24,648
Preferred shares issued	32,490
Common shares issued	71,478
Total consideration given	$128,616
Allocation of purchase price	
Cash acquired	$620
Accounts receivable	3,536
Inventory	180
Other current assets	106
Oil and natural gas properties	
Evaluated oil and natural gas properties	16,524
Unproved oil and unevaluated natural gas properties	201,521
Other property and equipment	178
Accounts payable	(2,551)
Accrued liabilities	(1,504)
Current note payable	(11,982)
Asset retirement obligations	(2,046)
Deferred tax liabilities incurred	(75,966)
Net assets acquired	$128,616

NOTE 4 - EQUITY
As discussed in Note 3, the Company issued 3,300,000 shares of common stock and 150,000 shares of a new series of Series A Preferred Stock to HEYCO Energy Group, Inc. in connection with the HEYCO Merger. Pursuant to the statement of resolutions, each share of Series A Preferred Stock would automatically convert into ten shares of Matador common stock, subject to customary anti-dilution adjustments, upon the vote and approval by Matador's shareholders of an amendment to Matador's Amended and Restated Certificate of Formation to increase the number of shares of authorized Matador common stock. Neither the issuance of the Series A Preferred Stock nor the common stock issued in connection with the HEYCO Merger were registered under the Securities Act of 1933, as amended (the "Securities Act"), and neither the Series A Preferred Stock nor such common stock may be offered or sold in the United States absent such registration or an applicable exemption from registration requirements. As part of the HEYCO Merger, the Company entered into a registration rights agreement with HEYCO Energy Group, Inc. providing certain

demand and piggyback registration rights, with demand registration rights exercisable beginning on February 27, 2016.
On April 2, 2015, the shareholders of the Company approved an amendment to the Company's Amended and Restated Certificate of Formation that authorized an increase in the number of authorized shares of common stock from 80,000,000 shares to 120,000,000 shares. Following such approval, the 150,000 outstanding shares of Series A Preferred Stock converted to 1,500,000 shares of common stock on April 6, 2015. Pursuant to the terms of the HEYCO Merger, 1,250,000 of the 1,500,000

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NOTE 4 - EQUITY - Continued

shares are being held in escrow to satisfy the post-closing adjustments to the merger consideration for title or environmental defects on the properties acquired in the merger.

On April 21, 2015, the Company completed a public offering of 7,000,000 shares of its common stock. After deducting offering costs totaling approximately $1.1 million, the Company received net proceeds of approximately $187.6 million. The Company used a portion of the net proceeds to repay $85.0 million in outstanding borrowings under its revolving credit facility (see Note 6), which amounts may be reborrowed in accordance with the terms of that facility. The remaining $102.6 million of net proceeds has been and is being used to fund a portion of the Company's working capital expenditures, including the addition of a third drilling rig in the Permian Basin in late July 2015 and targeted acquisitions of additional acreage in the Permian Basin, as well as in the Eagle Ford shale and the Haynesville shale, and for other general working capital needs.

Shares of treasury stock outstanding at September 30, 2015 and December 31, 2014 primarily represent forfeitures of non-vested restricted stock awards. On October 30, 2015, Matador's Board of Directors canceled all of the shares of treasury stock outstanding as of September 30, 2015. These shares were restored to the status of authorized but unissued shares of common stock of the Company.

NOTE 5 - ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company's asset retirement obligations for the nine months ended September 30, 2015 (in thousands).

Beginning asset retirement obligations	$11,951
Liabilities incurred during period	2,670
Liabilities settled during period	(436)
Revisions in estimated cash flows	(788)
Accretion expense	427
Ending asset retirement obligations	13,824
Less: current asset retirement obligations[1]	(411)
Long-term asset retirement obligations	$13,413

(1) Included in accrued liabilities in the Company's unaudited condensed consolidated balance sheet at September 30, 2015.

NOTE 6 - DEBT

Credit Agreement

On September 28, 2012, the Company entered into a third amended and restated credit agreement with the lenders party thereto (the "Credit Agreement"), which increased the maximum facility amount from $400.0 million to $500.0 million. At September 30, 2015, the Credit Agreement was scheduled to mature December 29, 2016. MRC Energy Company is the borrower under the Credit Agreement and is a subsidiary of Matador that, at September 30, 2015, directly or indirectly owned all of the ownership interests in the Company's other operating subsidiaries other than its less-than-wholly-owned subsidiaries. Borrowings are secured by mortgages on at least 80% of the Company's proved oil and natural gas properties and by the equity interests of MRC Energy Company's wholly-owned subsidiaries, which are also guarantors. In addition, all obligations under the Credit Agreement are guaranteed by Matador, the parent corporation. Various commodity hedging agreements with certain of the lenders under the Credit Agreement (or affiliates thereof) are also secured by the collateral of and guaranteed by certain eligible subsidiaries of MRC Energy Company.

The borrowing base under the Credit Agreement is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of the Company’s proved oil and natural gas reserves at December 31 and June 30 of each year, respectively. Both the Company and the lenders may request an unscheduled redetermination of the borrowing base once each between scheduled redetermination dates. During the second quarter of 2015, the lenders completed their review of the Company’s estimated total proved oil and natural gas reserves at December 31, 2014, and as a result, on April 6, 2015, the Company received notice that the borrowing base under the Credit Agreement would be reaffirmed at $450.0 million, and the

NOTE 6 - DEBT - Continued

conforming borrowing base would be reaffirmed at $375.0 million. Pursuant to an amendment to the Credit Agreement entered into concurrently with the issuance of $400.0 million of senior unsecured notes on April 14, 2015 discussed herein, the borrowing base was reduced to the conforming borrowing base of $375.0 million. During the fourth quarter of 2015, the lenders completed their review of the Company's estimated total proved oil and natural gas reserves at June 30, 2015, and as a result, on October 16, 2015, the Company amended the Credit Agreement to reaffirm the borrowing base at $375.0 million and extend the maturity date to October 16, 2020. This October 2015 redetermination constituted the regularly scheduled November 1 redetermination.

In the event of a borrowing base increase, the Company is required to pay a fee to the lenders equal to a percentage of the amount of the increase, which is determined based on market conditions at the time of the borrowing base increase. Total deferred loan costs associated with the Credit Agreement were $1.1 million at September 30, 2015, and these costs are being amortized over the term of the agreement, which approximates the amortization of these costs using the effective interest method. If, upon a redetermination or the automatic reduction of the borrowing base to the conforming borrowing base, the borrowing base were to be less than the outstanding borrowings under the Credit Agreement at any time, the Company would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or to repay the deficit in equal installments over a period of six months.

At September 30, 2015, the Company had no borrowings outstanding under the Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. During the nine months ended September 30, 2015, using a portion of the net proceeds from the senior unsecured notes offering and public offering of common stock discussed herein, the Company repaid a total of $465.0 million of its outstanding borrowings under the Credit Agreement. At November 4, 2015, the Company continued to have no borrowings outstanding under the Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement.

If the Company borrows funds as a base rate loan, such borrowings will bear interest at a rate equal to the higher of (i) the prime rate for such day, (ii) the Federal Funds Effective Rate (as defined in the Credit Agreement) on such day, plus 0.50% or (iii) the daily adjusting LIBOR rate (as defined in the Credit Agreement) plus 1.0% plus, in each case, an amount from 0.50% to 1.50% of such outstanding loan depending on the level of borrowings under the agreement. If the Company borrows funds as a Eurodollar loan, such borrowings will bear interest at a rate equal to (i) the quotient obtained by dividing (A) the LIBOR rate by (B) a percentage equal to 100% minus the maximum rate during such interest calculation period at which Royal Bank of Canada ("RBC") is required to maintain reserves on Eurocurrency Liabilities (as defined in Regulation D of the Board of Governors of the Federal Reserve System) plus (ii) an amount from 1.50% to 2.50% of such outstanding loan depending on the level of borrowings under the Credit Agreement. The interest period for Eurodollar borrowings may be one, two, three or six months as designated by the Company. A commitment fee of 0.375% to 0.50%, depending on the unused availability under the Credit Agreement, is also paid quarterly in arrears. The Company includes this commitment fee, any amortization of deferred financing costs (including origination, borrowing base increase and amendment fees) and annual agency fees, if any, as interest expense and in its interest rate calculations and related disclosures. The Credit Agreement requires the Company to maintain a debt to EBITDA (as defined in the Credit Agreement) ratio, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, of 4.25 or less.

Subject to certain exceptions, the Credit Agreement contains various covenants that limit the Company's ability to take certain actions, including, but not limited to, the following:

- incur indebtedness or grant liens on any of the Company's assets;
- enter into commodity hedging agreements;
- declare or pay dividends, distributions or redemptions;

- merge or consolidate;
- make any loans or investments;
- engage in transactions with affiliates;
- engage in certain asset dispositions, including a sale of all or substantially all of the Company’s assets; and
- take certain actions with respect to the Company’s senior unsecured notes.

If an event of default exists under the Credit Agreement, the lenders will be able to accelerate the maturity of the borrowings and exercise other rights and remedies. Events of default include, but are not limited to, the following events:

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NOTE 6 - DEBT - Continued

- failure to pay any principal or interest on the outstanding borrowings or any reimbursement obligation under any letter of credit when due or any fees or other amounts within certain grace periods;
- failure to perform or otherwise comply with the covenants and obligations in the Credit Agreement or other loan documents, subject, in certain instances, to certain grace periods;
- bankruptcy or insolvency events involving the Company or its subsidiaries; and
- a change of control, as defined in the Credit Agreement.

At September 30, 2015, the Company believes that it was in compliance with the terms of the Credit Agreement.

Senior Unsecured Notes

On April 14, 2015, Matador issued $400.0 million of 6.875% senior notes due 2023 (the "Original Notes") in a private placement. The Original Notes are Matador's senior unsecured obligations, are redeemable as described below and were issued at par value. The net proceeds were used to pay down a portion of the outstanding borrowings under the Credit Agreement and the debt assumed in connection with the HEYCO Merger. The Original Notes mature on April 15, 2023, and interest is payable semi-annually in arrears on April 15 and October 15 of each year. At September 30, 2015, the Original Notes were guaranteed on a senior unsecured basis by all of Matador's wholly-owned subsidiaries.

On October 21, 2015, and pursuant to a registered exchange offer, the Company exchanged all of the privately placed Original Notes for a like principal amount of 6.875% senior notes due 2023 that have been registered under the Securities Act (the "Registered Notes"). The terms of such Registered Notes are substantially the same as the terms of the Original Notes except that the transfer restrictions, registration rights and provisions for additional interest relating to the Original Notes do not apply to the Registered Notes.

On or after April 15, 2018, Matador may redeem all or a portion of the Registered Notes (the Registered Notes being referred to as the "Notes") at any time or from time to time at the following redemption prices (expressed as percentages of the principal amount) plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the twelve month period beginning on April 15 of the years indicated.

Year	Redemption Price
2018	105.156%
2019	103.438%
2020	101.719%
2021 and thereafter	100.000%

At any time prior to April 15, 2018, Matador may redeem up to 35% of the aggregate principal amount of the Notes with net proceeds from certain equity offerings at a redemption price of 106.875% of the principal amount of the Notes, plus accrued and unpaid interest, if any, to the redemption date; provided that (i) at least 65% in aggregate principal amount of the Notes (including any additional notes) originally issued remains outstanding immediately after the occurrence of such redemption (excluding Notes held by Matador and its subsidiaries) and (ii) each such redemption occurs within 180 days of the date of the closing of the related equity offering.

In addition, at any time prior to April 15, 2018, Matador may redeem all or part of the Notes at a redemption price equal to the sum of:

(i) the principal amount thereof, plus

(ii) the excess, if any, of (a) the present value at such time of (1) the redemption price of such Notes at April 15, 2018 plus (2) any required interest payments due on such Notes through April 15, 2018 discounted to the redemption date on a semi-annual basis using a discount rate equal to the Treasury Rate (as defined in the indenture governing the Notes (the "Indenture")) plus 50 basis points, over (b) the principal amount of such Notes, plus

(iii) accrued and unpaid interest, if any, to the redemption date.

Subject to certain exceptions, the Indenture contains various covenants that limit the Company’s ability to take certain actions, including, but not limited to, the following:

NOTE 6 - DEBT - Continued

- incur or guarantee additional debt or issue certain types of preferred stock;
- pay dividends on capital stock or redeem, repurchase or retire its capital stock or subordinated indebtedness;
- transfer or sell assets;
- make certain investments;
- create certain liens;
- enter into agreements that restrict dividends or other payments from its Restricted Subsidiaries (as defined in the Indenture) to the Company;
- consolidate, merge or transfer all or substantially all of its assets;
- engage in transactions with affiliates; and
- create unrestricted subsidiaries.

In the case of an event of default arising from certain events of bankruptcy or insolvency with respect to Matador, any Restricted Subsidiary that is a Significant Subsidiary (as defined in the Indenture) or any group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary, all outstanding Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding Notes may declare all the Notes to be due and payable immediately. Events of default include, but are not limited to, the following events:

- default for 30 days in the payment when due of interest on the Notes;
- default in the payment when due of the principal of, or premium, if any, on the Notes;
- failure by Matador to comply with its obligations to offer to purchase or purchase Notes when required pursuant to the change of control or asset sale provisions of the Indenture or Matador's failure to comply with the covenant relating to merger, consolidation or sale of assets;
- failure by Matador for 180 days after notice to comply with its reporting obligations under the Indenture;
- failure by Matador for 60 days after notice to comply with any of the other agreements in the Indenture;
- payment defaults and accelerations with respect to other indebtedness of Matador and its Restricted Subsidiaries in the aggregate principal amount of $25.0 million or more;
- failure by Matador or any Restricted Subsidiary to pay certain final judgments aggregating in excess of $25.0 million within 60 days;
- any subsidiary guarantee by a guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker; and
- certain events of bankruptcy or insolvency with respect to Matador or any Restricted Subsidiary that is a Significant Subsidiary or any group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary.

Note Payable

In connection with the HEYCO Merger, the Company assumed a note payable to PlainsCapital Bank in the amount of $12.5 million pursuant to which approximately $12.0 million of indebtedness was outstanding. The outstanding indebtedness was repaid on April 14, 2015 using a portion of the net proceeds from the Notes offering, and the related credit agreement and all associated obligations were terminated.

NOTE 7 - INCOME TAXES

The Company had an effective tax rate of 12.1% and 24.9% for the three and nine months ended September 30, 2015, respectively. The Company had an effective tax rate of 35.8% and 36.4% for the three and nine months ended September 30, 2014, respectively. At September 30, 2015, the Company's deferred tax assets exceeded its deferred tax liabilities; as a result, the Company recorded a valuation allowance of $66.6 million against most of the deferred tax assets. The valuation allowances will continue to be recognized until the realization of future deferred tax benefits are more likely than not to become utilized.

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NOTE 7 - INCOME TAXES - Continued

The total income tax benefit for the three and nine months ended September 30, 2015 differed from amounts computed by applying the U.S. federal statutory tax rate to loss before income taxes primarily due to the recording of the valuation allowance against the net deferred tax assets which resulted from the full-cost ceiling impairment recorded in the third quarter of 2015. The total income tax provision for the three and nine months ended September 30, 2014 differed from amounts computed by applying the U.S. federal statutory tax rate to income before income taxes primarily due to state tax expenses and nondeductible expenses.

The total income tax benefit of $33.3 million and $149.0 million for the three and nine months ended September 30, 2015 included $33.3 million and $140.3 million, respectively, of deferred income tax benefit resulting from full-cost ceiling impairments recorded in each period.

NOTE 8 - STOCK-BASED COMPENSATION

In January 2015, the Company granted awards of 113,289 shares of restricted stock and options to purchase 607,995 shares of the Company's common stock at an exercise price of $22.01 to certain of its employees. The fair value of these awards at the date of grant was approximately $8.4 million. In August 2015, the Company granted an award of 182,250 shares of restricted stock to certain of its employees. The fair value of these awards on the date of grant was approximately $4.1 million. All of these awards vest over a term of three years.

NOTE 9 - DERIVATIVE FINANCIAL INSTRUMENTS

From time to time, the Company uses derivative financial instruments to mitigate its exposure to commodity price risk associated with oil, natural gas and natural gas liquids ("NGL") prices. These instruments consist of put and call options in the form of costless collar and swap contracts. The Company records derivative financial instruments in its consolidated balance sheet as either assets or liabilities measured at fair value. The Company has elected not to apply hedge accounting for its existing derivative financial instruments. As a result, the Company recognizes the change in derivative fair value between reporting periods currently in its consolidated statement of operations as an unrealized gain or unrealized loss. The fair value of the Company's derivative financial instruments is determined using industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. RBC, Comerica Bank, The Bank of Nova Scotia and BMO Harris Financing (Bank of Montreal) (or affiliates thereof) were the counterparties for the Company's commodity derivatives at September 30, 2015. The Company has considered the credit standings of the counterparties in determining the fair value of its derivative financial instruments.

The Company has entered into various costless collar contracts to mitigate its exposure to fluctuations in oil prices, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss pursuant to any of these transactions is the arithmetic average of the settlement prices for the NYMEX West Texas Intermediate oil futures contract for the first nearby month corresponding to the calculation period's calendar month. When the settlement price is below the price floor established by one or more of these collars, the Company receives from the counterparty an amount equal to the difference between the settlement price and the price floor multiplied by the contract oil volume. When the settlement price is above the price ceiling established by one or more of these collars, the Company pays to the counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract oil volume.

The Company has entered into various costless collar transactions for natural gas, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss to the Company pursuant to any of these transactions is the settlement price for the NYMEX Henry Hub natural gas futures contract for the delivery month corresponding to the calculation period's calendar month for the settlement date of that contract period. When the settlement price is below the price floor established by one or more of these collars, the Company receives from the counterparty an amount equal to the difference between the settlement price and the price floor multiplied by the contract natural gas volume. When the settlement price is above the price ceiling established by one or more of these collars, the Company pays to the counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract natural gas volume.

The Company has entered into various swap contracts to mitigate its exposure to fluctuations in NGL prices, each with an established fixed price. For each calculation period, the settlement price for determining the realized gain or loss to the Company pursuant to any of these transactions is the arithmetic average of any current month for delivery on the nearby month futures contracts of the underlying commodity as stated on the “Mont Belvieu Spot Gas Liquids Prices: NON-TET prop” on the

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NOTE 9 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

pricing date. When the settlement price is below the fixed price established by one or more of these swaps, the Company receives from the counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract NGL volume. When the settlement price is above the fixed price established by one or more of these swaps, the Company pays to the counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract NGL volume.

At September 30, 2015, the Company had various costless collar contracts open and in place to mitigate its exposure to oil and natural gas price volatility, each with a specific term (calculation period), notional quantity (volume hedged) and price floor and ceiling. Each contract is set to expire at varying times during 2015 and 2016.

At September 30, 2015, the Company had various swap contracts open and in place to mitigate its exposure to NGL price volatility, each with a specific term (calculation period), notional quantity (volume hedged) and fixed price. Each contract is set to expire at varying times during 2015.

The following is a summary of the Company’s open costless collar contracts for oil and natural gas and open swap contracts for NGL at September 30, 2015.

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Price Floor ($/Bbl)	Price Ceiling ($/Bbl)	Fair Value of Asset (Liability) (thousands)
Oil	10/01/2015 - 12/31/2015	40,000	45.00	68.75	$246
Oil	10/01/2015 - 12/31/2015	50,000	50.00	67.85	782
Oil	10/01/2015 - 12/31/2015	20,000	80.00	100.00	2,053
Oil	10/01/2015 - 12/31/2015	20,000	80.00	101.00	2,052
Oil	10/01/2015 - 12/31/2015	20,000	83.00	96.12	2,232
Oil	10/01/2015 - 12/31/2015	20,000	83.00	97.00	2,233
Oil	10/01/2015 - 12/31/2015	20,000	85.00	99.00	2,352
Oil	10/01/2015 - 12/31/2015	20,000	85.00	100.00	2,353
Oil	10/01/2015 - 12/31/2015	20,000	85.00	105.10	2,352
Oil	10/01/2015 - 12/31/2016	40,000	55.00	68.35	5,097
Oil	01/01/2016 - 12/31/2016	40,000	43.00	77.05	1,267
Oil	01/01/2016 - 12/31/2016	50,000	45.00	77.75	2,038
Total open oil costless collar contracts					25,057

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NOTE 9 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

Commodity	Calculation Period	Notional Quantity (MMBtu/month)	Price Floor ($/MMBtu)	Price Ceiling ($/MMBtu)	Fair Value of Asset (Liability) (thousands)
Natural Gas	10/01/2015 - 10/31/2015	150,000	2.75	3.19	28
Natural Gas	10/01/2015 - 12/31/2015	100,000	2.75	3.05	58
Natural Gas	10/01/2015 - 12/31/2015	100,000	2.75	3.15	60
Natural Gas	10/01/2015 - 12/31/2015	100,000	2.75	3.11	59
Natural Gas	10/01/2015 - 12/31/2015	300,000	2.88	3.18	279
Natural Gas	10/01/2015 - 12/31/2015	100,000	3.75	4.36	347
Natural Gas	10/01/2015 - 12/31/2015	100,000	3.75	4.45	347
Natural Gas	10/01/2015 - 12/31/2015	100,000	3.75	4.60	347
Natural Gas	10/01/2015 - 12/31/2015	100,000	3.75	4.65	347
Natural Gas	10/01/2015 - 12/31/2015	200,000	3.75	5.04	694
Natural Gas	10/01/2015 - 12/31/2015	100,000	3.75	5.34	346
Natural Gas	01/01/2016 - 12/31/2016	200,000	2.75	3.50	409
Natural Gas	01/01/2016 - 12/31/2016	200,000	2.75	3.86	501
Natural Gas	01/01/2016 - 12/31/2016	300,000	2.75	3.95	784
Total open natural gas costless collar contracts					4,606

Commodity	Calculation Period	Notional Quantity (Gal/month)	Fixed Price ($/Gal)	Fair Value of Asset (Liability) (thousands)
Propane	10/01/2015 - 12/31/2015	150,000	1.000	239
Propane	10/01/2015 - 12/31/2015	100,000	1.030	168
Propane	10/01/2015 - 12/31/2015	68,000	1.073	123
Total open NGL swap contracts				530
Total open derivative financial instruments				$30,193

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Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 9 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

These derivative financial instruments are subject to master netting arrangements; all but one counterparty allow for cross-commodity master netting provided the settlement dates for the commodities are the same. The Company does not present different types of commodities with the same counterparty on a net basis in its consolidated balance sheet. The following table presents the gross asset and liability fair values of the Company's commodity price derivative financial instruments and the location of these balances in the unaudited condensed consolidated balance sheet as of September 30, 2015 and December 31, 2014 (in thousands).

Derivative Instruments	Gross amounts recognized	Gross amounts netted in the condensed consolidated balance sheets	Net amounts presented in the condensed consolidated balance sheets
September 30, 2015			
Current assets	$29,131	$(966)	$28,165
Other assets	2,685	(657)	2,028
Current liabilities	(979)	979	—
Other liabilities	(644)	644	—
Total	$30,193	$—	$30,193
December 31, 2014			
Current assets	$56,255	$(706)	$55,549
Current liabilities	(706)	706	—
Total	$55,549	$—	$55,549

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Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 9 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

The following table summarizes the location and aggregate fair value of all derivative financial instruments recorded in the unaudited condensed consolidated statements of operations for the periods presented (in thousands). These derivative financial instruments are not designated as hedging instruments.

		Three Months Ended September 30,		Nine Months Ended September 30,	
Type of Instrument	Location in Condensed Consolidated Statement of Operations	2015	2014	2015	2014
Derivative Instrument					
Oil	Revenues: Realized gain (loss) on derivatives	$17,056	$(816)	$42,013	$(4,523)
Natural Gas	Revenues: Realized gain (loss) on derivatives	2,215	19	8,531	(757)
NGL	Revenues: Realized gain (loss) on derivatives	591	96	1,602	(178)
Realized gain (loss) on derivatives		19,862	(701)	52,146	(5,458)
Oil	Revenues: Unrealized gain (loss) on derivatives	6,421	14,106	(19,923)	6,359
Natural Gas	Revenues: Unrealized gain (loss) on derivatives	808	1,933	(4,035)	1,362
NGL	Revenues: Unrealized (loss) gain on derivatives	(496)	254	(1,398)	229
Unrealized gain (loss) on derivatives		6,733	16,293	(25,356)	7,950
Total		$26,595	$15,592	$26,790	$2,492

NOTE 10 - FAIR VALUE MEASUREMENTS

The Company measures and reports certain financial and non-financial assets and liabilities on a fair value basis. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements are classified and disclosed in one of the following categories in the fair value hierarchy:

Level 1	Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Active markets are considered to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
Level 2	Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that are valued with industry standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument and can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace.
Level 3	Unobservable inputs that are not corroborated by market data. This category is comprised of financial and non-financial assets and liabilities whose fair value is estimated based on internally developed models or methodologies using significant inputs that are generally less readily observable from objective sources.

Financial and non-financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 10 - FAIR VALUE MEASUREMENTS - Continued

The following tables summarize the valuation of the Company’s financial assets and liabilities that were accounted for at fair value on a recurring basis in accordance with the classifications provided above as of September 30, 2015 and December 31, 2014 (in thousands).

	Fair Value Measurements at September 30, 2015 using			
Description	Level 1	Level 2	Level 3	Total
Assets				
Oil, natural gas and NGL derivatives	$—	30,193	$—	30,193
Total	$—	30,193	$—	30,193

	Fair Value Measurements at December 31, 2014 using			
Description	Level 1	Level 2	Level 3	Total
Assets				
Oil, natural gas and NGL derivatives	$—	$55,549	$—	$55,549
Total	$—	$55,549	$—	$55,549

Additional disclosures related to derivative financial instruments are provided in Note 9.

Other Fair Value Measurements

At September 30, 2015 and December 31, 2014, the carrying values reported on the unaudited condensed consolidated balance sheets for accounts receivable, prepaid expenses, accounts payable, accrued liabilities, royalties payable, advances from joint interest owners, amounts due to joint ventures, income taxes payable and other current liabilities approximate their fair values due to their short-term maturities.

At September 30, 2015 and December 31, 2014, the carrying value of borrowings under the Credit Agreement approximates fair value as it is subject to short-term floating interest rates, which represent Level 2 inputs in the fair value hierarchy and reflect market rates available to the Company at the time.

At September 30, 2015, the fair value of the Company’s Notes was $385.0 million based on quoted market prices, which represent Level 1 inputs in the fair value hierarchy. The Company had no Notes outstanding at December 31, 2014.

NOTE 11 - COMMITMENTS AND CONTINGENCIES

Office Lease
The Company leases office facilities under operating leases. In June 2015, the Company entered into the seventh amendment of its Dallas corporate office lease agreement. This amendment increased the Company’s total leased space from approximately 40,000 square feet to approximately 100,000 square feet effective January 2016.
From time to time, the Company also enters into leases for field offices in locations where the Company has active field operations. These leases are typically for terms of less than five years and are not considered principal properties.
The following is a schedule of future minimum lease payments required under all office lease agreements as of September 30, 2015 for the remaining three months of 2015, the twelve months ending December 31, 2016, 2017, 2018 and 2019, and all periods thereafter (in thousands).

	Amount
2015	$224
2016	2,017
2017	2,432
2018	2,488
2019	2,528
Thereafter	17,597
Total	$27,286

Natural Gas and NGL Processing and Transportation Commitments
Effective September 1, 2012, the Company entered into a firm five-year natural gas processing and transportation agreement whereby the Company committed to transport the anticipated natural gas production from a significant portion of its Eagle Ford acreage in South Texas through the counterparty’s system for processing at the counterparty’s facilities. The agreement also includes firm transportation of the NGL extracted at the counterparty’s processing plant downstream for fractionation. After processing, the residue natural gas is purchased by the counterparty at the tailgate of its processing plant and further transported under its natural gas transportation agreements. The arrangement contains fixed processing and liquids transportation and fractionation fees, and the revenue the Company receives varies with the quality of natural gas transported to the processing facilities and the contract period.
Under this agreement, if the Company does not meet 80% of the maximum thermal quantity transportation and processing commitments in a contract year, it will be required to pay a deficiency fee per MMBtu of natural gas deficiency. Any quantity in excess of the maximum MMBtu delivered in a contract year can be carried over to the next contract year for purposes of calculating the natural gas deficiency. During certain prior periods, the Company had an immaterial natural gas deficiency, and the counterparty to this agreement waived the deficiency fee. The Company’s remaining aggregate undiscounted minimum commitments under this agreement are $3.8 million at September 30, 2015. The Company paid $1.6 million and $1.5 million in processing and transportation fees under this agreement during the three months ended September 30, 2015 and 2014, respectively, and $4.3 million in processing and transportation fees under this agreement during both the nine months ended September 30, 2015 and 2014.
Other Commitments
The Company does not own or operate its own drilling rigs, but instead enters into contracts with third parties for such rigs. These contracts establish daily rates for the drilling rigs and the term of the Company’s commitment for the drilling services to be provided, which have typically been for one year or less, although the Company has recently begun to enter into longer-term contracts in order to secure new drilling rigs equipped with the latest technology in plays that were until recently experiencing heavy demand for drilling rigs. The Company would incur a termination obligation if the Company elected to terminate a contract and the drilling contractor were unable to secure work for the contracted drilling rigs or if the drilling contractor were unable to secure replacement work for the contracted drilling rigs at the same daily rates being charged to the Company prior to the end of their respective contract terms.

The Company’s undiscounted minimum outstanding aggregate termination obligations under its drilling rig contracts were approximately $43.8 million at September 30, 2015.

The Company entered into an agreement in 2014 with a third party for the engineering, procurement, construction and installation of the Processing Plant. The Processing Plant was designed to process a portion of the Company’s natural gas

NOTE 11 - COMMITMENTS AND CONTINGENCIES - Continued

produced from certain of its wells in the Permian Basin, as well as third-party natural gas. At September 30, 2015, total remaining commitments under this contract were $2.1 million, and the Company made payments totaling $2.2 million and $14.2 million during the three and nine months ended September 30, 2015, respectively. The Company made no payments under this contract during the three and nine months ended September 30, 2014. The Processing Plant was completed on August 31, 2015 and was sold on October 1, 2015 (see Note 15).

At September 30, 2015, the Company had agreed to participate in the drilling and completion of various non-operated wells. If all of these wells are drilled and completed, the Company will have undiscounted minimum outstanding aggregate commitments for its participation in these wells of approximately $21.8 million at September 30, 2015, which the Company expects to incur within the next few months.

Legal Proceedings

The Company is a defendant in several lawsuits encountered in the ordinary course of its business. While the ultimate outcome and impact to the Company cannot be predicted with certainty, in the opinion of management, it is remote that these lawsuits will have a material adverse impact on the Company’s financial condition, results of operations or cash flows.

NOTE 12 - SUPPLEMENTAL DISCLOSURES

Accrued Liabilities

The following table summarizes the Company’s current accrued liabilities at September 30, 2015 and December 31, 2014 (in thousands).

	September 30, 2015	December 31, 2014
Accrued evaluated and unproved and unevaluated property costs	$54,654	$86,259
Accrued support equipment and facilities costs	6,815	4,290
Accrued lease operating expenses	12,970	9,034
Accrued interest on borrowings under the Credit Agreement and the Notes	12,757	206
Accrued asset retirement obligations	411	311
Accrued partners’ share of joint interest charges	4,081	3,767
Accrued stock-based compensation	1,082	—
Other	9,557	5,635
Total accrued liabilities	$102,327	$109,502

Supplemental Cash Flow Information

The following table provides supplemental disclosures of cash flow information for the nine months ended September 30, 2015 and 2014 (in thousands).

	Nine Months Ended September 30,	
	2015	2014
Cash paid for interest expense, net of amounts capitalized	$2,617	$3,667
Asset retirement obligations related to mineral properties	$1,487	$3,305
Asset retirement obligations related to support equipment and facilities	$89	$132
(Decrease) increase in liabilities for oil and natural gas properties capital expenditures	$(30,282)	$43,692
Increase in liabilities for support equipment and facilities	$2,525	$2,488
Stock-based compensation expense recognized as liability	$191	$789
Transfer of inventory from oil and natural gas properties	$586	$300

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Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 13 - SUBSIDIARY GUARANTORS

Matador filed a registration statement on Form S-3 with the SEC in 2013, which became effective on May 9, 2013, and a registration statement on Form S-3 with the SEC in 2014, which became effective upon filing on May 22, 2014, registering, in each case, among other securities, senior and subordinated debt securities and guarantees of debt securities by certain subsidiaries of Matador (the “Shelf Guarantor Subsidiaries”). On April 14, 2015, the Company issued the Original Notes (see Note 6), which are jointly and severally guaranteed by certain subsidiaries of Matador (the “Notes Guarantor Subsidiaries” and, together with the Shelf Guarantor Subsidiaries, the “Guarantor Subsidiaries”) on a full and unconditional basis (except for customary release provisions). On June 1, 2015, Matador filed a registration statement on Form S-4 with the SEC in connection with the exchange of the Original Notes for the Registered Notes, including guarantees by each of the Notes Guarantor Subsidiaries. The Form S-4 was declared effective by the SEC on September 16, 2015. The Company completed the exchange of all the Original Notes for Registered Notes on October 21, 2015. At September 30, 2015, the Guarantor Subsidiaries are 100% owned by Matador, and any subsidiaries of Matador other than the Guarantor Subsidiaries are minor. Matador is a parent holding company and has no independent assets or operations, and there are no significant restrictions on the ability of Matador to obtain funds from the Guarantor Subsidiaries by dividend or loan.

NOTE 14 - RELATED PARTY TRANSACTIONS

In June 2015, the Company entered into two joint ventures to develop certain leasehold interests held by certain affiliates (the “HEYCO Affiliates”) of HEYCO Energy Group, Inc., the former parent company of HEYCO. The HEYCO Affiliates are owned by George M. Yates, who is a member of the Company’s Board of Directors, and certain of his affiliates. Pursuant to the terms of the transaction, the HEYCO Affiliates contributed an aggregate of approximately 1,900 net acres, primarily in the same properties previously held by HEYCO, to the two newly-formed entities in exchange for a 50% interest in each entity. The Company has agreed to contribute an aggregate of $14.2 million in exchange for the other 50% interest in both entities. As of September 30, 2015, the Company had contributed an aggregate of approximately $0.7 million to the two entities. The Company’s contributions will be used to fund future capital expenditures associated with the interests being acquired as well as to fund acquisitions of other non-operated acreage opportunities.

Additionally, substantially all of the oil production from the wells acquired in the HEYCO Merger is subject to pre-existing sales contracts with an entity owned by affiliates of HEYCO Energy Group, Inc. The Company recorded revenue of $1.1 million for oil sold pursuant to such contracts for the nine months ended September 30, 2015. Such contracts were terminated in the third quarter of 2015.

NOTE 15 - SUBSEQUENT EVENTS

On October 1, 2015, the Company completed the sale of its wholly-owned subsidiary that owned the Loving County System to EnLink. The Loving County System includes the Processing Plant and approximately six miles of high-pressure gathering pipeline which connects the Company’s gathering system to the Processing Plant.

Pursuant to the terms of the transaction, EnLink paid the Company approximately $143 million, excluding customary purchase price adjustments. In conjunction with the sale of the Loving County System, the Company dedicated its leasehold interests in Loving County as of the closing date pursuant to a 15-year, fixed-fee gathering and processing agreement and provided a volume commitment in exchange for priority one service. The Company can, at its option, dedicate any future leasehold acquisitions in Loving County to EnLink. In addition, the Company retained its natural gas gathering system up to a central delivery point and its other midstream assets in the area, including oil and water gathering systems and salt water disposal wells.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes thereto contained herein and in our Annual Report on Form 10-K for the year ended December 31, 2014 (the "Annual Report") filed with the Securities and Exchange Commission ("SEC"), along with Management's Discussion and Analysis of Financial Condition and Results of Operations contained in the Annual Report. The Annual Report is accessible on the SEC's website at www.sec.gov and on our website at www.matadorresources.com. Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with the "Risk Factors" section of the Annual Report and the section entitled "Cautionary Note Regarding Forward-Looking Statements" below for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

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In this Quarterly Report on Form 10-Q (the "Quarterly Report"), references to "we," "our" or the "Company" refer to Matador Resources Company and its subsidiaries as a whole and references to "Matador" refer solely to Matador Resources Company.

For certain oil and natural gas terms used in this report, please see the "Glossary of Oil and Natural Gas Terms" included with the Annual Report.

Cautionary Note Regarding Forward-Looking Statements

Certain statements in this Quarterly Report constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. Additionally, forward-looking statements may be made orally or in press releases, conferences, reports, on our website or otherwise, in the future, by us or on our behalf. Such statements are generally identifiable by the terminology used such as "anticipate," "believe," "continue," "could," "estimate," "expect," "inter "may," "might," "potential," "predict," "project," "should" or other similar words.

By their very nature, forward-looking statements require us to make assumptions that may not materialize or that may not be accurate. Forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: the integration of the assets, employees and operations of Harvey E. Yates Company following its merger with one of our wholly-owned subsidiaries on February 27, 2015, changes in oil or natural gas prices, the success of our drilling program, the timing and amount of planned capital expenditures, having sufficient cash flow from operations together with available borrowing capacity under our revolving credit facility, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, availability of acquisitions, uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, and the other factors discussed below and elsewhere in this Quarterly Report and in other documents that we file with or furnish to the SEC, all of which are difficult to predict. Forward-looking statements may include statements about:

- our business strategy;
- our reserves;
- our technology;
- our cash flows and liquidity;
- our financial strategy, budget, projections and operating results;
- our oil and natural gas realized prices;
- the timing and amount of future production of oil and natural gas;
- the availability of drilling and production equipment;
- the availability of oil field labor;
- the amount, nature and timing of capital expenditures, including future exploration and development costs;
- the availability and terms of capital;
- our drilling of wells;
- government regulation and taxation of the oil and natural gas industry;

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- our marketing of oil and natural gas;
- our exploitation projects or property acquisitions;
- the integration of Harvey E. Yates Company with our business;
- our costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;
- competition in the oil and natural gas industry;
- the effectiveness of our risk management and hedging activities;
- environmental liabilities;
- counterparty credit risk;
- developments in oil-producing and natural gas-producing countries;
- our future operating results;
- estimated future reserves and the present value thereof;
- our plans, objectives, expectations and intentions contained in this Quarterly Report that are not historical; and
- other factors discussed in the Annual Report.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity, achievements or financial condition.

You should not place undue reliance on any forward-looking statement and should recognize that the statements are predictions of future results, which may not occur as anticipated. Actual results could differ materially from those anticipated in the forward-looking statements and from historical results, due to the risks and uncertainties described above, as well as others not now anticipated. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors. The foregoing statements are not exclusive and further information concerning us, including factors that potentially could materially affect our financial results, may emerge from time to time. We do not intend to update forward-looking statements to reflect actual results or changes in factors or assumptions affecting such forward-looking statements except as required by law, including the securities laws of the United States and the rules and regulations of the SEC.

Overview

We are an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. Our current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Permian (Delaware) Basin in Southeast New Mexico and West Texas and the Eagle Ford shale play in South Texas. We also operate in the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas.

Third Quarter and Year-to-Date Highlights

For the three months ended September 30, 2015, our total oil equivalent production was 2.41 million BOE and our average daily oil equivalent production was 26,137 BOE per day, of which 12,617 Bbl per day, or 48%, was oil and 81.1 MMcf per day, or 52%, was natural gas. Our natural gas production of 7.5 Bcf, or 81.1 MMcf per day, was the best quarterly natural gas production result in our Company’s history. For the nine months ended September 30, 2015, our total oil equivalent production was 6.94 million BOE, averaging 25,427 BOE per day, our total oil production was 3.43 million Bbl, averaging 12,562 Bbl per day, and our total natural gas production was 21.1 Bcf, averaging 77.2 MMcf per day. These results were the best results for any nine-month period in our Company’s history.

During the third quarter of 2015, our oil and natural gas revenues were $71.8 million, a decrease of 26% from oil and natural gas revenues of $96.6 million during the third quarter of 2014. This decrease was attributable to a sharp decline in the weighted average oil and natural gas prices to $43.21 per Bbl and $2.90 per Mcf, respectively, realized in the third quarter of 2015 from weighted average oil and natural gas prices of $92.39 per Bbl and $4.95 per Mcf, respectively, realized in the third quarter of 2014. The decrease in our oil and natural gas revenues was mitigated by the 38% increase in our oil production to 1.16 million Bbl in the third quarter of 2015, as compared to 839,000 Bbl produced in the third quarter of 2014, and by the 94% increase in our natural gas production to 7.5 Bcf in the third quarter of 2015, as compared to 3.8 Bcf in the third quarter of 2014. The increase in oil production was primarily a result of increased oil production from newly drilled and completed wells

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in the Delaware Basin, as well as from newly drilled and completed wells in the Eagle Ford shale in early 2015. The increase in natural gas production was primarily attributable to new, non-operated Haynesville shale wells completed and placed on production on our Elm Grove properties in Northwest Louisiana in the latter half of 2014 and throughout 2015, but also includes increased natural gas production associated with our operations in both the Delaware Basin and the Eagle Ford shale. For the three months ended September 30, 2015, our Adjusted EBITDA was $58.0 million, a decrease of 13% from Adjusted EBITDA of $66.8 million during the three months ended September 30, 2014.

For the nine months ended September 30, 2015, our oil and natural gas revenues were $222.1 million, a decrease of 19% from oil and natural gas revenues of $274.6 million for the first nine months of 2014. This decrease was attributable to a sharp decline in the weighted average oil and natural gas prices to $47.36 per Bbl and $2.83 per Mcf, respectively, realized in the nine months ended September 30, 2015 from weighted average oil and natural gas prices of $95.45 per Bbl and $5.53 per Mcf, respectively, realized in the nine months ended September 30, 2014. The decrease in our oil and natural gas revenues was mitigated by the 49% increase in our oil production to 3.43 million Bbl in the nine months ended September 30, 2015, as compared to 2.30 million Bbl produced in the nine months ended September 30, 2014, and by a 112% increase in our natural gas production to 21.1 Bcf for the nine months ended September 30, 2015, as compared to 9.9 Bcf for the nine months ended September 30, 2014. This increase in oil and natural gas production was attributable to the same operations noted above for the three months ended September 30, 2015. For the nine months ended September 30, 2015, our Adjusted EBITDA was $174.9 million, a decrease of 9% from Adjusted EBITDA of $192.6 million for the nine months ended September 30, 2014. Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see "— Liquidity and Capital Resources — Non-GAAP Financial Measures." For more information regarding our financial results for 2015, see "— Results of Operations" below.

On October 1, 2015, we completed the sale of the equity interests of our wholly-owned subsidiary that owned certain natural gas gathering and processing assets in the Delaware Basin in Loving County, Texas (the "Loving County System") to a subsidiary of EnLink Midstream Partners, LP ("EnLink"). The Loving County System included a cryogenic natural gas processing plant with approximately 35 million cubic feet per day of inlet capacity (the "Processing Plant") and approximately six miles of high-pressure gathering pipeline which connects our gathering system to the Processing Plant.

Pursuant to the terms of the transaction, EnLink paid the Company cash consideration of approximately $143 million, excluding customary purchase price adjustments. In conjunction with the sale of the Loving County System, we dedicated our leasehold interests in Loving County as of the closing date of the transaction pursuant to a 15-year, fixed-fee gathering and processing agreement and provided a volume commitment in exchange for priority one service. We can, at our option, dedicate any future leasehold acquisitions in Loving County to EnLink. In addition, we retained our natural gas gathering system up to a central delivery point and our other midstream assets in the area, including oil and water gathering systems and salt water disposal wells.

At the beginning of 2015, we were operating five drilling rigs, two rigs in the Eagle Ford and three rigs in the Permian (Delaware) Basin, but we reduced our operated drilling rigs to two by the end of the first quarter of 2015, with both operating in the Delaware Basin. In late July 2015, we took delivery of a third drilling rig which began drilling three stacked, horizontal wells from a single pad in our Jackson Trust prospect area in northeast Loving County, Texas testing the Brushy Canyon, Avalon and Second Bone Spring formations in this area. At November 4, 2015, these three wells had been drilled and just recently completed but were not yet flowing back after stimulation. We are currently operating three drilling rigs in the Delaware Basin, one in Loving County, Texas, one in Eddy County, New Mexico and one in Lea County, New Mexico. We are also participating in non-operated wells in the Delaware Basin as these opportunities arise. We completed our planned operated drilling and completion activities in the Eagle Ford shale for 2015 in the second quarter. We expect to continue to participate in several non-operated Haynesville shale wells drilled by a subsidiary of Chesapeake Energy Corporation ("Chesapeake") and other operating partners during the remainder of 2015.

As a result of beginning to drill wells faster, increasing working interests on certain operated wells, participating in additional non-operated wells proposed on our acreage, increasing our focus on drilling more, deeper Wolfcamp wells in the Delaware Basin (as opposed to shallower Bone Spring wells) than originally planned for 2015, adding a third drilling rig in the Delaware Basin in late July 2015, allocating additional capital to the acquisition of oil and natural gas leases and expanding our midstream investment plans, on August 4, 2015 we raised our estimated 2015 capital expenditure budget from $350 million to $425 million (excluding capital expenditures associated with the HEYCO Merger (defined below)). At September 30, 2015, we had incurred $356 million, or approximately 84%, of our increased 2015 capital expenditure budget of $425.0 million (excluding capital expenditures associated with the HEYCO Merger (defined below)).

During the third quarter of 2015, we completed and began producing oil and natural gas from 11 gross (4.7 net) wells in the Delaware Basin, including four gross (4.0 net) operated wells and seven gross (0.7 net) non-operated wells, throughout our various prospect areas. As of the end of the third quarter of 2015, we had drilled an additional five wells that were in the process of completion, including two Wolfcamp “A”/“Y” wells on our Billy Burt leasehold in our Wolf prospect area in Loving County, Texas and the three-well batch at Jackson Trust mentioned above. As a result of our ongoing drilling and completion operations in these prospect areas, our Delaware Basin production has continued to increase over the past twelve months. Our total Delaware Basin production for the third quarter of 2015 was 7,551 BOE per day, consisting of 5,489 Bbl of oil per day and 12.4 MMcf of natural gas per day, an almost four-fold increase from production of 2,084 BOE per day, consisting of 1,486 Bbl of oil per day and 3.6 MMcf of natural gas per day, in the third quarter of 2014. The Delaware Basin contributed approximately 44% of our daily oil production and approximately 15% of our daily natural gas production in the third quarter of 2015, as compared to only about 16% of our daily oil production and approximately 9% of our daily natural gas production in the third quarter of 2014.

We continue to make significant progress in reducing drilling costs and times for both Wolfcamp and Bone Spring horizontal wells. Our focus on improving drilling times and operational efficiencies has cut drilling times by as much as 50% or more on recent Wolfcamp wells in the Wolf and Rustler Breaks prospect areas as compared to earlier wells drilled in these prospect areas. In the Wolf prospect area in Loving County, Texas, for example, Wolfcamp drilling times (spud to total depth) have been reduced from an average of 43 days in 2014 to as low as 22 days on recent wells. In the Rustler Breaks prospect area in Eddy County, New Mexico, where the Wolfcamp formation is shallower, Wolfcamp drilling times have been reduced from an average of 32 days in 2014 and early 2015 to as low as 15 days on recent wells. In addition, at November 4, 2015 our most recent Second Bone Spring horizontal well in our Rustler Breaks prospect area was drilled from spud to total depth in only 12 days, making it the fastest Second Bone Spring horizontal well we have drilled to date. These increased drilling efficiencies are the result of a number of factors such as Company-supported modifications to our contracted drilling rigs, including 7,500-psi circulating systems, simultaneous operating capabilities, integrated equipment upgrades and other efficiency-related modifications, as well as more experienced personnel on each rig, improved bit designs and starting to drill wells in “batch” mode in some areas.

These increased drilling and completion efficiencies, coupled with service cost reductions of varying amounts, have begun to reduce overall well costs. Recent Wolfcamp wells in the Wolf prospect area have been drilled and completed for approximately $7 to $8 million, as compared to $10 to $12 million in 2014 and early 2015. In the Rustler Breaks prospect area, Wolfcamp drilling and completion costs have been reduced to between $5.8 and $6.5 million per well, and a recent Bone Spring well in this area was drilled and completed for approximately $4 million. These well costs are substantially reduced from those of initial wells drilled in these areas and from well costs originally budgeted in early 2015 for many of these wells. We plan to continue to focus on these operational efficiencies as we move closer to full development of our Delaware Basin assets.

We also participated in two gross (0.4 net) non-operated Haynesville shale wells that were completed and placed on production during the third quarter of 2015. Both wells came on production at 12 to 14 MMcf of natural gas per day (about 5.7 MMcf of natural gas per day net to our interest). Drilling and completion costs for these wells continued to be in the range of $7 to $7.5 million. Our combined Haynesville and Cotton Valley natural gas production for the third quarter of 2015, primarily in Northwest Louisiana, was 51.3 MMcf per day, a year-over-year increase of 137% from 21.6 MMcf per day in the third quarter of 2014. This increased production was attributable to the ongoing drilling and completion operations in the Haynesville shale by Chesapeake on our Elm Grove properties in Northwest Louisiana during 2014 and 2015. We completed our planned operated Eagle Ford drilling and completion operations for 2015 in the second quarter of 2015 and did not complete or begin producing oil and natural gas from any new Eagle Ford wells during the third quarter of 2015.

At December 31, 2014, we held 92,700 gross (66,100 net) acres in the Permian Basin, primarily in Lea and Eddy Counties, New Mexico and Loving County, Texas. Between January 1, 2015 and November 4, 2015, we added approximately 66,000 gross (24,600 net) acres in the Permian Basin, including the approximately 58,600 gross (18,200 net) acres in Lea and Eddy Counties, New Mexico acquired in our February 2015 business combination with Harvey E. Yates Company, a subsidiary of HEYCO Energy Group, Inc. (the “HEYCO Merger”) and approximately 1,900 net acres contributed into joint ventures into which we entered with certain affiliates of HEYCO Energy Group, Inc. As a result, at November 4, 2015 our total acreage position in the Permian Basin in Southeast New Mexico and West Texas was 158,700 gross (90,700 net) acres. In the third quarter of 2015, we also acquired approximately 385 gross (385 net) acres prospective for the Eagle Ford shale in Karnes County, Texas adjacent to our Sickenius prospect. We plan to continue our leasing and acquisition efforts in the Permian Basin, Eagle Ford shale and Haynesville shale as opportunities are identified.

At September 30, 2015, our estimated total proved oil and natural gas reserves were 87.1 million BOE, including 42.5 million Bbl of oil and 267.5 Bcf of natural gas, with a PV-10 of $692.7 million and a Standardized Measure of $673.8 million. At December 31, 2014, our estimated proved oil and natural gas reserves were 68.7 million BOE, including 24.2 million Bbl of oil and 267.1 Bcf of natural gas, and at September 30, 2014, our estimated proved oil and natural gas reserves were 61.0 million BOE, including 21.5 million Bbl of oil and 236.7 Bcf of natural gas. Our proved oil reserves of 42.5 million Bbl at September 30, 2015 almost doubled, as compared to 21.5 million Bbl at September 30, 2014, and increased 76%, as compared to 24.2 million Bbl at December 31, 2014. These reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

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We realized a weighted average oil price of $43.21 per Bbl for the three months ended September 30, 2015, as compared to $92.39 per Bbl for the three months ended September 30, 2014. Most of our Eagle Ford oil production in South Texas is sold based on a Louisiana Light Sweet oil price index less transportation costs. Oil production from our properties in the Delaware Basin in Southeast New Mexico and West Texas is sold on a West Texas Intermediate at Midland oil price index less transportation costs. We realized a weighted average natural gas price of $2.90 per Mcf for the three months ended September 30, 2015, as compared to $4.95 per Mcf for the three months ended September 30, 2014. This price reflects an uplift as a result of natural gas liquids we produce with our Eagle Ford and Delaware Basin natural gas production. Our natural gas production from the Haynesville shale is mostly dry natural gas and does not receive a price uplift as a result of natural gas liquids. See "— Results of Operations" below for more information on our oil and natural gas prices realized during the third quarter of 2015.

On October 16, 2015, we amended our third amended and restated credit agreement (the "Credit Agreement") to extend the maturity date from December 29, 2016 to October 16, 2020. In connection with the amendment, our lenders unanimously reaffirmed the borrowing base under our Credit Agreement at $375.0 million, based on our lenders' review of our proved oil and natural gas reserves at June 30, 2015, and the maximum facility amount remained unchanged at $500.0 million. At September 30, 2015 and November 4, 2015, we had no borrowings outstanding under our Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to our Credit Agreement.

Estimated Proved Reserves

The following table sets forth our estimated total proved oil and natural gas reserves at September 30, 2015, December 31, 2014 and September 30, 2014. Our production and proved reserves are reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Where we produce liquids-rich natural gas, such as in the Eagle Ford shale and the Delaware Basin, the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold. These reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers. These reserves estimates were prepared in accordance with the SEC's rules for oil and natural gas reserves reporting. The estimated reserves shown are for proved reserves only and do not include any unproved reserves classified as probable or possible reserves that might exist for our properties, nor do they include any consideration that would be attributable to interests in unproved and unevaluated acreage beyond those tracts for which proved reserves have been estimated. Proved oil and natural gas reserves are quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our total proved reserves are estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

	September 30, 2015	December 31, 2014	September 30, 2014
Estimated Proved Reserves Data: (1) (2)			
Estimated proved reserves:			
Oil (MBbl)(3)	42,531	24,184	21,519
Natural Gas (Bcf)(4)	267.5	267.1	236.7
Total (MBOE)(5)	87,109	68,693	60,969
Estimated proved developed reserves:			
Oil (MBbl)(3)	17,413	14,053	12,192
Natural Gas (Bcf)(4)	97.7	102.8	78.3
Total (MBOE)(5)	33,685	31,185	25,242
Percent developed	38.7 %	45.4 %	41.4 %
Estimated proved undeveloped reserves:			
Oil (MBbl)(3)	25,118	10,131	9,327
Natural Gas (Bcf)(4)	169.8	164.3	158.4

Total (MBOE)(5)	53,424	37,508	35,727
PV-10(6) (in millions)	$692.7	$1,043.4	$952.0
Standardized Measure(7) (in millions)	$673.8	$913.3	$835.1

(1) Numbers in table may not total due to rounding.

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(2) Our estimated proved reserves, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic averages of the first-day-of-the-month prices for the period from October 2014 through September 2015 were $55.73 per Bbl for oil and $3.06 per MMBtu for natural gas, for the period from January 2014 through December 2014 were $91.48 per Bbl for oil and $4.35 per MMBtu for natural gas and for the period from October 2013 through September 2014 were $95.56 per Bbl for oil and $4.24 per MMBtu for natural gas. These prices were adjusted by property for quality, energy content, regional price differentials, transportation fees, marketing deductions and other factors affecting the price received at the wellhead. We report our proved reserves in two streams, oil and natural gas, and the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold.

(3) One thousand barrels of oil.

(4) One billion cubic feet of natural gas.

(5) One thousand barrels of oil equivalent, estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(6) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. Our PV-10 at September 30, 2015, December 31, 2014 and September 30, 2014 may be reconciled to the Standardized Measure of discounted future net cash flows at such dates by reducing our PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at September 30, 2015, December 31, 2014 and September 30, 2014 were, in millions, $18.9, $130.1 and $116.9, respectively.

(7) Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties.

At September 30, 2015, our estimated total proved oil and natural gas reserves were 87.1 million BOE, including 42.5 million Bbl of oil and 267.5 Bcf of natural gas, with a PV-10 of $692.7 million and a Standardized Measure of $673.8 million. At December 31, 2014, our estimated total proved oil and natural gas reserves were 68.7 million BOE, including 24.2 million Bbl of oil and 267.1 Bcf of natural gas, and at September 30, 2014, our estimated total proved oil and natural gas reserves were 61.0 million BOE, including 21.5 million Bbl of oil and 236.7 Bcf of natural gas. Our proved oil reserves of 42.5 million Bbl at September 30, 2015 increased 76%, as compared to 24.2 million Bbl at December 31, 2014, and almost doubled, as compared to 21.5 million Bbl at September 30, 2014. During the nine months ended September 30, 2015, our proved developed reserves increased 8% from 31.2 million BOE at December 31, 2014 to 33.7 million BOE at September 30, 2015. Year-over-year, our proved developed reserves increased 33% from 25.2 million BOE at September 30, 2014. At September 30, 2015, approximately 39% of our total proved reserves were proved developed reserves, 49% of our total proved reserves were oil and 51% of our total proved reserves were natural gas. As a result of the sharp decline in commodity prices used to estimate proved reserves at September 30, 2015, certain of our proved undeveloped reserves, in particular natural gas proved undeveloped reserves in portions of the Haynesville shale, were reclassified to contingent resources and are no longer considered proved reserves under SEC guidelines.

There have been no changes to the technology we used to establish reserves or to our internal control over the reserves estimation process from those set forth in the Annual Report.

Critical Accounting Policies

Other than as described below, there have been no changes to our critical accounting policies and estimates from those set forth in the Annual Report.

Assets Held for Sale

On the date at which certain assets meet all the criteria required to be classified as assets held for sale, we discontinue the recording of depletion and depreciation of the assets or asset group to be sold and reclassify the assets and related liabilities to be sold as held for sale on the consolidated balance sheets. The assets and liabilities are measured at the lower of their carrying amount or estimated fair value less estimated cost to sell. The most significant estimates in these calculations typically relate to estimated fair value.

Allocation of Purchase Price in Business Combinations

As part of our business strategy, we periodically pursue the acquisition of oil and natural gas properties. The purchase price in a business combination is allocated to the assets acquired and liabilities assumed based on their fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. The most significant estimates in the allocation typically relate to the value assigned to proved oil and natural gas reserves and unproved and unevaluated properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

Recent Accounting Pronouncements

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Revenue from Contracts with Customers. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update, or ("ASU"), 2014-09, Revenue from Contracts with Customers (Topic 606), which specifies how and when to recognize revenue. This standard also requires expanded disclosures surrounding revenue recognition and is intended to improve and converge with international standards the financial reporting requirements for revenue from contracts with customers. ASU 2014-09 will become effective for fiscal years beginning after December 15, 2017, i.e., in our first fiscal quarter of 2018. We are currently evaluating the impact, if any, of the adoption of this ASU on our consolidated financial statements.

Interest - Imputation of Interest. In April 2015, the FASB issued ASU 2015-03, Interest - Imputation of Interest (Subtopic 935-30): Simplifying the Presentation of Debt Issuance Costs, which requires companies that have historically presented debt issuance costs as an asset to present those costs as a direct deduction from the carrying amount of the underlying debt liability. The guidance requires retrospective application in financial statements issued for fiscal years and interim periods beginning after December 15, 2015 but early adoption is permitted. The Company adopted this ASU effective June 30, 2015. See "Note 2 – Summary of Significant Accounting Policies" to the unaudited condensed consolidated financial statements in this Quarterly Report for a description of the impact of the adoption of this standard on our consolidated financial statements.

Results of Operations

Revenues

The following table summarizes our unaudited revenues and production data for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Operating Data:				
Revenues (in thousands):[(1)]				
Oil	$50,173	$77,546	$162,424	$219,714
Natural gas	21,642	19,071	59,704	54,891
Total oil and natural gas revenues	71,815	96,617	222,128	274,605
Realized gain (loss) on derivatives	19,862	(701)	52,146	(5,458)
Unrealized gain (loss) on derivatives	6,733	16,293	(25,356)	7,950
Total revenues	$98,410	$112,209	$248,918	$277,097
Net Production Volumes:[(1)]				
Oil (MBbl)[(2)]	1,161	839	3,429	2,302
Natural gas (Bcf)[(3)]	7.5	3.8	21.1	9.9
Total oil equivalent (MBOE)[(4)]	2,405	1,481	6,941	3,956
Average daily production (BOE/d)[(5)]	26,137	16,096	25,427	14,490
Average Sales Prices:				
Oil, with realized derivatives (per Bbl)	$57.90	$91.42	$59.61	$93.48
Oil, without realized derivatives (per Bbl)	$43.21	$92.39	$47.36	$95.45
Natural gas, with realized derivatives (per Mcf)	$3.28	$4.99	$3.31	$5.44
Natural gas, without realized derivatives (per Mcf)	$2.90	$4.95	$2.83	$5.53

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(1) We report our production volumes in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Revenues associated with extracted natural gas liquids are included with our natural gas revenues.

(2) One thousand barrels of oil.

(3) One billion cubic feet of natural gas.

(4) One thousand barrels of oil equivalent, estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(5) Barrels of oil equivalent per day, estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

Three Months Ended September 30, 2015 as Compared to Three Months Ended September 30, 2014

Oil and natural gas revenues. Our oil and natural gas revenues decreased by $24.8 million, or 26%, to $71.8 million for the three months ended September 30, 2015, as compared to $96.6 million for the three months ended September 30, 2014. Our oil revenues decreased by $27.4 million, or 35%, to $50.2 million for the three months ended September 30, 2015, as compared

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to $77.5 million for the three months ended September 30, 2014. The decrease in oil revenues resulted from a lower weighted average oil price realized in the third quarter of 2015 of $43.21 per Bbl, as compared to $92.39 per Bbl realized for the third quarter of 2014. This decrease in realized oil price was partially mitigated by the increase in our oil production of 38% to 1.16 million Bbl of oil in the third quarter of 2015, or 12,617 Bbl of oil per day, as compared to 839,000 Bbl of oil in the third quarter of 2014, or 9,123 Bbl of oil per day. This increase in oil production was primarily a result of increased oil production from newly drilled and completed wells in the Delaware Basin, as well as from newly drilled and completed wells in the Eagle Ford shale in early 2015. Our natural gas revenues increased by $2.6 million, or 13%, to $21.6 million for the three months ended September 30, 2015, as compared to $19.1 million for the three months ended September 30, 2014. The increase in natural gas revenues resulted from an increase in our natural gas production by 94% to 7.5 Bcf for the three months ended September 30, 2015, as compared to 3.8 Bcf for the three months ended September 30, 2014. The increase in natural gas production was primarily attributable to the increased natural gas production resulting from new, non-operated Haynesville shale wells completed and placed on production on our Elm Grove properties in Northwest Louisiana during the latter half of 2014 and into 2015, but also includes increased natural gas production associated with our operations in the Delaware Basin and the Eagle Ford shale. The increase in production was partially offset by a lower weighted average natural gas price of $2.90 per Mcf realized during the third quarter of 2015, as compared to a weighted average natural gas price of $4.95 per Mcf realized during the third quarter of 2014.

Realized gain (loss) on derivatives. Our realized gain on derivatives was $19.9 million for the three months ended September 30, 2015, as compared to a realized loss of $0.7 million for the three months ended September 30, 2014. For the three months ended September 30, 2015, we realized a net gain of $17.1 million, $2.2 million and $0.6 million attributable to our oil, natural gas and natural gas liquids (“NGL”) derivative contracts, respectively. For the three months ended September 30, 2014, we realized a net loss of $0.8 million and a net gain of $0.1 million attributable to our oil and NGL derivative contracts, respectively. The realized gain on our oil and natural gas derivative contracts during the three months ended September 30, 2015 resulted from oil and natural gas prices that were lower than the floor prices of several of our oil and natural gas costless collar contracts. The realized gain in NGL derivative contracts during the three months ended September 30, 2015 resulted from NGL prices that were lower than the fixed prices of our NGL swap contracts. We realized a gain of approximately $21.06 per Bbl and $0.51 per MMBtu hedged on all of our oil and natural gas derivative contracts during the three months ended September 30, 2015, respectively, as compared to a loss of $1.23 per Bbl hedged on our oil derivative contracts during the three months ended September 30, 2014. The average floor prices of our oil costless collar contracts were $67.11 per Bbl and $87.82 per Bbl as of September 30, 2015 and September 30, 2014, respectively. The average ceiling prices of our oil costless collar contracts were $84.60 per Bbl and $98.95 per Bbl as of September 30, 2015 and September 30, 2014, respectively. During the third quarter of 2015, our natural gas costless collar contracts had average floor and ceiling prices of $3.26 per MMBtu and $3.94 per MMBtu, respectively, as compared to $3.50 per MMBtu and $4.93 per MMBtu, respectively, during the third quarter of 2014. The realized loss on derivatives on our oil derivatives contracts during the three months ended September 30, 2014 resulted from oil prices that were higher than the ceiling prices of several of our oil costless collar contracts. The realized gain on our NGL derivative contracts resulted from NGL prices that were lower than the fixed prices of our NGL swap contracts. Our total oil and natural gas volumes hedged for the three months ended September 30, 2015 were 22% higher and 32% higher, respectively, than the total oil and natural gas volumes hedged for the same period in 2014.

Unrealized gain on derivatives. Our unrealized gain on derivatives was $6.7 million for the three months ended September 30, 2015, as compared to an unrealized gain of $16.3 million for the three months ended September 30, 2014. During the period from June 30, 2015 to September 30, 2015, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts increased from $23.5 million to $30.2 million, resulting in an unrealized gain on derivatives of $6.7 million for the three months ended September 30, 2015. The net fair value of our open oil derivative contracts increased $6.4 million at September 30, 2015, as compared to June 30, 2015, primarily due to lower oil futures prices at September 30, 2015. The net fair value of our open natural gas derivative contracts increased $0.8 million at September 30, 2015, as compared to June 30, 2015, primarily due to lower natural gas futures prices at September 30, 2015. The net fair value of our open NGL derivative contracts decreased $0.5 million at September 30, 2015, as compared to June 30, 2015, primarily due to the realized revenues from contracts settled during the three months ended September 30, 2015. During the period from June 30, 2014 to September 30, 2014, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts increased from a net liability of $11.1 million to a net asset of $5.2 million due to decreases in futures prices for these commodities, resulting in an unrealized gain on derivatives of $16.3 million for the three months ended September 30, 2014.

Nine Months Ended September 30, 2015 as Compared to Nine Months Ended September 30, 2014

Oil and natural gas revenues. Our oil and natural gas revenues decreased by approximately $52.5 million, or 19%, to approximately $222.1 million for the nine months ended September 30, 2015, as compared to $274.6 million for the nine months ended September 30, 2014. Our oil revenues decreased by 26% to $162.4 million for the nine months ended September 30, 2015, as compared to $219.7 million for the nine months ended September 30, 2014. The decrease in oil revenues resulted from a lower weighted average oil price realized in the nine months ended September 30, 2015 of $47.36 per Bbl, as compared to $95.45 per Bbl realized for the nine months ended September 30, 2014. The lower weighted average oil price realized was

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partially mitigated by our oil production increase of 49% to 3.43 million Bbl of oil in the nine months ended September 30, 2015, or about 12,562 Bbl of oil per day, as compared to 2.30 million Bbl of oil, or about 8,432 Bbl of oil per day, in the nine months ended September 30, 2014. This increased oil production was primarily a result of increased oil production from newly drilled and completed wells in the Delaware Basin, as well as from newly drilled and completed wells in the Eagle Ford shale in early 2015. Our natural gas revenues increased by $4.8 million, or 9%, to $59.7 million for the nine months ended September 30, 2015, as compared to $54.9 million for the nine months ended September 30, 2014. Our natural gas production increased by 112% to 21.1 Bcf for the nine months ended September 30, 2015, as compared to 9.9 Bcf for the nine months ended September 30, 2014. The increase in natural gas production was primarily attributable to the increased natural gas production resulting from new, non-operated Haynesville shale wells completed and placed on production on our Elm Grove properties in Northwest Louisiana during the latter half of 2014 and into 2015, but also includes increased natural gas production associated with our operations in the Delaware Basin and the Eagle Ford shale. This production increase was largely offset by a lower weighted average natural gas price of $2.83 per Mcf realized during the nine months ended September 30, 2015, as compared to a weighted average natural gas price of $5.53 per Mcf realized during the nine months ended September 30, 2014.

Realized gain (loss) on derivatives. We realized a gain on derivatives of approximately $52.1 million for the nine months ended September 30, 2015, as compared to a loss of approximately $5.5 million for the nine months ended September 30, 2014. For the nine months ended September 30, 2015, we realized net gains of approximately $42.0 million, $8.5 million and $1.6 million attributable to our oil, natural gas and NGL derivative contracts, respectively. For the nine months ended September 30, 2014, we realized net losses of approximately $4.5 million, $0.8 million and $0.2 million attributable to our oil, natural gas and NGL derivative contracts, respectively. The net gain realized from our derivative contracts for the nine months ended September 30, 2015 resulted from oil and natural gas prices that were below the floor prices of several of our oil and natural gas derivative contracts during the nine months ended September 30, 2015, as well as NGL prices that were below the fixed prices on several of our NGL derivative contracts during the nine months ended September 30, 2015. We realized a gain of approximately $22.00 per Bbl and $0.64 per MMBtu hedged on all of our oil and natural gas derivative contracts, respectively, during the nine months ended September 30, 2015, as compared to a loss of $2.34 per Bbl and $0.08 per MMBtu hedged on all of our oil and natural gas derivative contracts, respectively, during the nine months ended September 30, 2014. During the nine months ended September 30, 2015, our natural gas costless collar contracts had average floor and ceiling prices of $3.42 per MMBtu and $4.19 per MMBtu, respectively, as compared to $3.48 per MMBtu and $4.94 per MMBtu, respectively, for the nine months ended September 30, 2014. The average floor prices of our oil costless collar contracts were $71.77 per Bbl and $87.76 per Bbl as of September 30, 2015 and September 30, 2014, respectively. The average ceiling prices of our oil costless collar contracts were $89.04 per Bbl and $99.48 per Bbl as of September 30, 2015 and September 30, 2014, respectively. Our total oil and natural gas volumes hedged for the nine months ended September 30, 2015 were 1% lower and 44% higher, respectively, than the total oil and natural gas volumes hedged for the same period in 2014.

Unrealized gain (loss) on derivatives. Our unrealized loss on derivatives was approximately $25.4 million for the nine months ended September 30, 2015, as compared to an unrealized gain of approximately $8.0 million for the nine months ended September 30, 2014. During the period from December 31, 2014 through September 30, 2015, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts decreased from approximately $55.5 million to approximately $30.2 million, resulting in an unrealized loss on derivatives of approximately $25.4 million for the nine months ended September 30, 2015. This loss is primarily attributable to realized revenue from oil, natural gas and NGL derivative contracts settled during the nine months ended September 30, 2015. During the period from December 31, 2013 through September 30, 2014, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts increased from a net liability of $2.8 million to a net asset of $5.2 million, resulting in an unrealized gain on derivatives of $8.0 million for the nine months ended September 30, 2014.

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Expenses

The following table summarizes our unaudited operating expenses and other income (expense) for the periods indicated:

	Three Months Ended September 30,