Matador Resources Co
Form 10-Q
August 05, 2016

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 June 30, 2016
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number 001-35410

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	75240
(Address of principal executive offices)	(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 August 3, 2016, there were 93,307,151 shares of the registrant’s common stock, par value $0.01 per share, outstanding.

MATADOR RESOURCES COMPANY
FORM 10-Q
FOR THE QUARTER ENDED JUNE 30, 2016
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Part I – FINANCIAL INFORMATION
Item 1. Financial Statements — Unaudited

Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED BALANCE SHEETS - UNAUDITED
(In thousands, except par value and share data)

	June 30, 2016	December 31, 2015
ASSETS		
Current assets		
Cash	$40,873	$ 16,732
Restricted cash	460	44,357
Accounts receivable		
Oil and natural gas revenues	25,382	16,616
Joint interest billings	16,641	16,999
Other	5,137	10,794
Derivative instruments	117	16,284
Lease and well equipment inventory	3,002	2,022
Prepaid expenses	3,017	3,203
Total current assets	94,629	127,007
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	2,272,738	2,122,174
Unproved and unevaluated	397,883	387,504
Other property and equipment	122,374	86,387
Less accumulated depletion, depreciation and amortization	(1,802,464)	(1,583,659)
Net property and equipment	990,531	1,012,406
Other assets	928	1,448
Total assets	$1,086,088	$ 1,140,861
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current liabilities		
Accounts payable	$9,468	$ 10,966
Accrued liabilities	80,754	92,369
Royalties payable	16,646	16,493
Amounts due to affiliates	4,032	5,670
Derivative instruments	9,760	—
Advances from joint interest owners	5,783	700
Deferred gain on plant sale	5,903	4,830
Amounts due to joint ventures	3,522	2,793
Income taxes payable	—	2,848
Other current liabilities	210	161
Total current liabilities	136,078	136,830
Long-term liabilities		
Senior unsecured notes payable	391,845	391,254
Asset retirement obligations	18,498	15,166
Amounts due to joint ventures	3,228	3,956
Derivative instruments	7,538	—
Deferred gain on plant sale	99,286	102,506
Other long-term liabilities	7,086	2,190

Total long-term liabilities	527,481	515,072
Commitments and contingencies (Note 10)		
Shareholders' equity		
Common stock - $0.01 par value, 120,000,000 shares authorized; 93,374,455 and 85,567,021 shares issued; and 93,290,199 and 85,564,435 shares outstanding, respectively	934	856
Additional paid-in capital	1,172,983	1,026,077
Retained deficit	(752,437)	(538,930)
Total Matador Resources Company shareholders' equity	421,480	488,003
Non-controlling interest in subsidiaries	1,049	956
Total shareholders' equity	422,529	488,959
Total liabilities and shareholders' equity	$ 1,086,088	$ 1,140,861

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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Revenues				
Oil and natural gas revenues	$69,336	$87,848	$113,262	$150,314
Realized gain on derivatives	2,465	13,780	9,528	32,285
Unrealized loss on derivatives	(26,625)	(23,532)	(33,464)	(32,090)
Total revenues	45,176	78,096	89,326	150,509
Expenses				
Production taxes and marketing	10,556	10,258	18,459	17,308
Lease operating	13,174	14,950	28,664	27,996
Depletion, depreciation and amortization	31,248	51,768	60,170	98,239
Accretion of asset retirement obligations	289	132	552	244
Full-cost ceiling impairment	78,171	229,026	158,633	296,153
General and administrative	13,197	12,961	26,360	26,372
Total expenses	146,635	319,095	292,838	466,312
Operating loss	(101,459)	(240,999)	(203,512)	(315,803)
Other income (expense)				
Net gain (loss) on asset sales and inventory impairment	1,002	—	2,067	(97)
Interest expense	(6,167)	(5,869)	(13,365)	(7,939)
Interest and other income	877	502	1,396	886
Total other expense	(4,288)	(5,367)	(9,902)	(7,150)
Loss before income taxes	(105,747)	(246,366)	(213,414)	(322,953)
Income tax provision (benefit)				
Deferred	—	(89,350)	—	(115,740)
Total income tax benefit	—	(89,350)	—	(115,740)
Net loss	(105,747)	(157,016)	(213,414)	(207,213)
Net income attributable to non-controlling interest in subsidiaries	(106)	(75)	(93)	(111)
Net loss attributable to Matador Resources Company shareholders	$(105,853)	$(157,091)	$(213,507)	$(207,324)
Earnings (loss) per common share				
Basic	$(1.15)	$(1.89)	$(2.40)	$(2.65)
Diluted	$(1.15)	$(1.89)	$(2.40)	$(2.65)
Weighted average common shares outstanding				
Basic	92,346	82,938	88,826	78,379
Diluted	92,346	82,938	88,826	78,379

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 Six Months Ended June 30, 2016

	Common Stock Shares	Common Stock Amount	Additional paid-in capital	Retained 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, 2016	85,567	$ 856	$ 1,026,077	$ (538,930)	2	$ —	$ 488,003	$ 956	$ 488,959
Issuance of common stock	7,500	75	142,275	—	—	—	142,350	—	142,350
Cost to issue equity	—	—	(830)	—	—	—	(830)	—	(830)
Stock-based compensation expense related to equity-based awards	—	—	5,464	—	—	—	5,464	—	5,464
Stock options exercised	11	—	—	—	—	—	—	—	—
Restricted stock issued	273	3	(3)	—	—	—	—	—	—
Restricted stock forfeited	—	—	—	—	82	—	—	—	—
Vesting of restricted stock units	24	—	—	—	—	—	—	—	—
Current period net loss	—	—	—	(213,507)	—	—	(213,507)	93	(213,414)
Balance at June 30, 2016	93,375	$ 934	$ 1,172,983	$ (752,437)	84	$ —	$ 421,480	$ 1,049	$ 422,529

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)

	Six Months Ended June 30,	
	2016	2015
Operating activities		
Net loss	$(213,414)	$(207,213)
Adjustments to reconcile net loss to net cash provided by operating activities		
Unrealized loss on derivatives	33,464	32,090
Depletion, depreciation and amortization	60,170	98,239
Accretion of asset retirement obligations	552	244
Full-cost ceiling impairment	158,633	296,153
Stock-based compensation expense	5,553	5,131
Deferred income tax benefit	—	(115,740)
Amortization of debt issuance cost	592	—
Net (gain) loss on asset sales and inventory impairment	(2,067)	97
Changes in operating assets and liabilities		
Accounts receivable	(2,751)	(12,161)
Lease and well equipment inventory	(514)	(269)
Prepaid expenses	186	(1,143)
Other assets	520	446
Accounts payable, accrued liabilities and other current liabilities	2,451	13,316
Royalties payable	153	4,253
Advances from joint interest owners	5,083	447
Income taxes payable	(2,848)	(444)
Other long-term liabilities	3,837	(56)
Net cash provided by operating activities	49,600	113,390
Investing activities		
Oil and natural gas properties capital expenditures	(162,381)	(237,027)
Expenditures for other property and equipment	(47,548)	(32,885)
Business combination, net of cash acquired	—	(23,671)
Restricted cash	43,437	—
Restricted cash in less-than-wholly-owned subsidiaries	460	(413)
Net cash used in investing activities	(166,032)	(293,996)
Financing activities		
Repayments of borrowings	—	(476,982)
Borrowings under Credit Agreement	—	125,000
Proceeds from issuance of senior unsecured notes	—	400,000
Cost to issue senior unsecured notes	—	(8,789)
Proceeds from issuance of common stock	142,350	188,720
Cost to issue equity	(768)	(1,172)
Proceeds from stock options exercised	—	10
Capital contribution from non-controlling interest owners in less-than-wholly-owned subsidiaries	—	600
Taxes paid related to net share settlement of stock-based compensation	(1,009)	(1,565)
Net cash provided by financing activities	140,573	225,822
Increase in cash	24,141	45,216
Cash at beginning of period	16,732	8,407

Cash at end of period	$40,873	$53,623

Supplemental disclosures of cash flow information (Note 11)

The accompanying notes are an integral part of these financial statements.
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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 Delaware Basin in Southeast New Mexico and West Texas. The Company also operates in the Eagle Ford shale play in South Texas and 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 interim 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, 2015 (the “Annual Report”) filed with the SEC. The Company proportionately 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 interim unaudited condensed consolidated financial statements as of June 30, 2016. Amounts as of December 31, 2015 are derived from the Company’s 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.
Change in Accounting Principle
During the second quarter of 2016, the Company adopted Accounting Standards Update (“ASU”) 2016-09, Compensation - Stock Compensation (Topic 718), which simplifies several aspects of the accounting for employee share-based payment transactions, including accounting for income tax, forfeitures, statutory tax withholding requirements, classifications of awards as either equity or liability and classification of taxes in the statement of cash flows, requiring either retrospective, modified retrospective or prospective transition. The amended guidance also requires an entity to record excess tax benefits and deficiencies in the income statement. The adoption of this ASU had no impact on any period presented for (i) the Company’s financial position or statements of operations, as the Company currently has a valuation allowance against its net deferred tax assets, or (ii) the Company’s statements of cash flows, as the Company has historically accounted for taxes paid for net share settlement as a financing activity as required under this ASU. In addition, the Company uses historical forfeiture rates to estimate future forfeitures

attributable to the service-based vesting requirements not being met and will continue to do so upon adoption of this ASU.

Property and Equipment

The Company uses the full-cost method of accounting for its investments in oil and natural gas properties. Under this method, the Company is required to perform a ceiling test each quarter which determines a limit, or ceiling, on the capitalized costs of oil and natural gas properties based primarily on the after-tax estimated future net cash flows from oil and natural gas properties using a 10% discount rate and the arithmetic average of first-day-of-the-month oil and natural gas prices for the prior

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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

12-month period. Due primarily to declines in oil and natural gas prices, the capitalized costs of oil and natural gas properties exceeded the cost center ceiling, and as a result, the Company recorded impairment charges to its net capitalized costs in its unaudited condensed consolidated statements of operations of $78.2 million and $229.0 million for the three months ended June 30, 2016 and 2015, respectively, and $158.6 million and $296.2 million for the six months ended June 30, 2016 and 2015, respectively.

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.

The Company capitalized approximately $4.0 million and $1.9 million of its general and administrative costs for the three months ended June 30, 2016 and 2015, respectively, and approximately $1.7 million and $1.3 million of its interest expense for the three months ended June 30, 2016 and 2015, respectively. The Company capitalized approximately $6.0 million and $3.5 million of its general and administrative costs for the six months ended June 30, 2016 and 2015, respectively, and approximately $2.2 million and $2.3 million of its interest expense for the six months ended June 30, 2016 and 2015, respectively.

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 (loss) 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 six months ended June 30, 2016 and 2015 (in thousands).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Weighted average common shares outstanding				
Basic	92,346	82,938	88,826	78,379
Dilutive effect of options, restricted stock units and preferred shares	—	—	—	—
Diluted weighted average common shares outstanding	92,346	82,938	88,826	78,379

A total of 2.9 million options to purchase shares of the Company's common stock and 0.1 million restricted stock units were excluded from the diluted weighted average common shares outstanding for both the three and six months ended June 30, 2016, respectively, because their effects were anti-dilutive. Additionally, 0.9 million restricted shares, which are participating securities, were excluded from the calculations above for both the three and six months ended June 30, 2016, respectively, as the security holders do not have the obligation to share in the losses of the Company.

A total of 2.5 million options to purchase shares of the Company's common stock and 0.1 million restricted stock units were excluded from the diluted weighted average common shares outstanding for both the three and six months ended June 30, 2015, respectively, and zero and 1.5 million preferred shares were excluded from the calculations above for both the three and six months ended June 30, 2015, respectively, because their effects were anti-dilutive. Additionally, 0.7 million restricted shares, which are participating securities, were excluded from the calculations above for both the three and six months ended June 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 Financial Accounting Standards Board (“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. This ASU will become effective for fiscal years beginning after December 15, 2017 with early adoption permitted for periods beginning after

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

December 15, 2016. Entities can transition to the standard either retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. The Company is currently evaluating the impact, if any, of the adoption of this ASU on its consolidated financial statements.

Leases. In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842), which requires the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous U.S. GAAP. This ASU will become effective for fiscal years beginning after December 15, 2018 with early adoption permitted. Entities are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. These practical expedients relate to the identification and classification of leases that commenced before the effective date, initial direct costs for leases that commenced before the effective date and the ability to use hindsight in evaluating lessee options to extend or terminate a lease or to purchase the underlying asset. The Company is currently evaluating the impact of the adoption of this ASU on its consolidated financial statements.

NOTE 3 - EQUITY

On March 11, 2016, the Company completed a public offering of 7,500,000 shares of its common stock. After deducting offering costs totaling approximately $0.8 million, the Company received net proceeds of approximately $141.5 million, which are being used for general corporate purposes, including to fund a portion of the Company’s current and future capital expenditures.

NOTE 4 - ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company’s asset retirement obligations for the six months ended June 30, 2016 (in thousands).

Beginning asset retirement obligations	$15,420
Liabilities incurred during period	1,044
Liabilities settled during period	(119)
Revisions in estimated cash flows	1,662
Accretion expense	552
Ending asset retirement obligations	18,559
Less: current asset retirement obligations[1]	(61)
Long-term asset retirement obligations	$18,498

(1) Included in accrued liabilities in the Company’s interim unaudited condensed consolidated balance sheet at June 30, 2016.

NOTE 5 - DEBT

At June 30, 2016 and August 3, 2016, the Company had $400 million of outstanding 6.875% senior notes due 2023 (the “Notes”), no borrowings outstanding under the Company’s revolving credit agreement (the “Credit Agreement”) and approximately $0.6 million and $0.8 million in outstanding letters of credit issued pursuant to the Credit Agreement, respectively.

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. On May 3, 2016, the borrowing base under the Credit Agreement was reduced to $300.0 million from $375.0 million based on the lenders’ review of the Company’s proved oil and natural gas reserves at December 31, 2015. At June 30, 2016, the borrowing base available under the Credit Agreement remained $300.0 million.

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. If, upon a

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

NOTE 5 - DEBT - Continued

redetermination of the 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.

The Company believes that it was in compliance with the terms of its Credit Agreement at June 30, 2016.

On April 14, 2015, the Company issued the Notes, which are jointly and severally guaranteed by certain subsidiaries of Matador (the "Guarantor Subsidiaries") on a full and unconditional basis (except for customary release provisions). At June 30, 2016, all of 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 6 - INCOME TAXES

The Company's deferred tax assets exceed its deferred tax liabilities due to the deferred tax assets generated by the full-cost ceiling impairment charges recorded; as a result, the Company established a valuation allowance against most of the deferred tax assets beginning in the third quarter of 2015. The Company retains a full valuation allowance at June 30, 2016 due to uncertainties regarding the future realization of its deferred tax assets. The valuation allowance will continue to be recognized until the realization of future deferred tax benefits are more likely than not to be utilized.

The total income tax benefit for the three and six months ended June 30, 2015 differed from amounts computed by applying the U.S. federal statutory tax rate to loss before income taxes due primarily to state tax apportionments and nondeductible expenses.

NOTE 7 - STOCK-BASED COMPENSATION

In February 2016, the Company granted awards of 243,428 shares of restricted stock and options to purchase 608,287 shares of the Company's common stock at an exercise price of $15.00 per share to certain of its employees. The fair value of these awards was approximately $7.0 million. All of these awards vest on the three-year anniversary of the grant date of these awards.

NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS

At June 30, 2016, 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 2016 and 2017.

The following is a summary of the Company's open costless collar contracts for oil and natural gas at June 30, 2016.

Commodity	Calculation Period	Notional Quantity (Bbl or MMBtu)	Weighted Average Price Floor ($/Bbl or $/MMBtu)	Weighted Average Price Ceiling ($/Bbl or $/MMBtu)	Fair Value of Asset (Liability) (thousands)
Oil	07/01/2016 - 12/31/2016	1,380,000	$ 42.48	$ 61.16	$ (2,091)
Oil	01/01/2017 - 12/31/2017	1,560,000	$ 38.62	$ 47.62	(11,801)
Natural Gas	07/01/2016 - 12/31/2016	7,200,000	$ 2.63	$ 3.61	(228)
Natural Gas	01/01/2017 - 12/31/2017	14,580,000	$ 2.38	$ 3.48	(3,061)
Total open derivative financial instruments					$ (17,181)

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 interim unaudited condensed consolidated balance sheets.

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

NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

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 interim unaudited condensed consolidated balance sheets as of June 30, 2016 and December 31, 2015 (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
June 30, 2016			
Current assets	$4,316	$ (4,199)	$ 117
Other assets	2,421	(2,421)	—
Current liabilities	(13,959)	4,199	(9,760)
Other liabilities	(9,959)	2,421	(7,538)
Total	$(17,181)	$ —	$ (17,181)
December 31, 2015			
Current assets	$16,767	$ (483)	$ 16,284
Current liabilities	(483)	483	—
Total	$16,284	$ —	$ 16,284

The following table summarizes the location and aggregate fair value of all derivative financial instruments recorded in the interim 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 June 30,		Six Months Ended June 30,	
Type of Instrument	Location in Condensed Consolidated Statement of Operations	2016	2015	2016	2015
Derivative Instrument					
Oil	Revenues: Realized gain on derivatives	$561	$10,524	$6,024	$24,957
Natural Gas	Revenues: Realized gain on derivatives	1,904	2,716	3,504	6,315
Natural Gas Liquids	Revenues: Realized gain on derivatives	—	540	—	1,013
Realized gain on derivatives		2,465	13,780	9,528	32,285
Oil	Revenues: Unrealized loss on derivatives	(19,319)	(19,880)	(26,974)	(26,345)
Natural Gas	Revenues: Unrealized loss on derivatives	(7,306)	(3,281)	(6,490)	(4,843)
Natural Gas Liquids	Revenues: Unrealized loss on derivatives	—	(371)	—	(902)
Unrealized loss on derivatives		(26,625)	(23,532)	(33,464)	(32,090)
Total		$(24,160)	$(9,752)	$(23,936)	$195

NOTE 9 - 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 for identical, unrestricted assets or liabilities in active markets.
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

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NOTE 9 - FAIR VALUE MEASUREMENTS - Continued

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 which reflect a company’s own market assumptions.

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.

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 June 30, 2016 and December 31, 2015 (in thousands).

	Fair Value Measurements at June 30, 2016 using			
Description	Level 1	Level 2	Level 3	Total
Liabilities				
Oil and natural gas derivatives	$—	$(17,181)	$ —	$(17,181)
Total	$—	$(17,181)	$ —	$(17,181)

	Fair Value Measurements at December 31, 2015 using			
Description	Level 1	Level 2	Level 3	Total
Assets				
Oil and natural gas derivatives	$—	$16,284	$ —	$16,284
Total	$—	$16,284	$ —	$16,284

Additional disclosures related to derivative financial instruments are provided in Note 8.

Other Fair Value Measurements

At June 30, 2016 and December 31, 2015, the carrying values reported on the interim unaudited condensed consolidated balance sheets for accounts receivable, prepaid expenses, accounts payable, accrued liabilities, royalties payable, amounts due to affiliates, advances from joint interest owners, amounts due to joint ventures, income taxes payable and other current liabilities approximated their fair values due to their short-term maturities.

At June 30, 2016 and December 31, 2015, the fair value of the Notes was $412.0 million and $381.0 million, respectively, based on quoted market prices, which represent Level 1 inputs in the fair value hierarchy.

NOTE 10 - COMMITMENTS AND CONTINGENCIES

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 natural gas liquids 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 payable by the Company, and the revenue the Company receives for the residue natural gas 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 $2.1 million at June 30, 2016. The Company paid $0.8 million and $1.4 million in processing and transportation fees under this agreement during the three months ended June 30, 2016 and 2015, respectively, and $1.7 million and $2.7 million in processing and transportation fees under this agreement during the six months ended June 30, 2016 and 2015, respectively.

In late 2015, the Company entered into a 15-year fixed-fee natural gas gathering and processing agreement whereby the Company committed to deliver the anticipated natural gas production from a significant portion of its Loving County, Texas acreage through the counterparty’s gathering system for processing at the counterparty’s facility. Under this agreement, if the Company does not meet the volume commitment for gathering and processing at the facility in a contract year, it will be required to pay a deficiency fee per MMBtu of natural gas deficiency. At the end of each year of the agreement, the Company can elect to have the previous year’s actual gathering and processing volumes be the new minimum commitment for each of the remaining years of the contract. As such, the Company has the ability to unilaterally reduce the gathering and processing commitment if the Company’s production in the Loving County area is less than the Company’s currently projected production. If the Company ceased operations in this area at June 30, 2016, the total deficiency fee required to be paid would be approximately $8.5 million. In addition, if the Company elects to reduce the gathering and processing commitment in any year, the Company has the ability to elect to increase the committed volumes in any future year to the originally agreed gathering and processing commitment. Any quantity in excess of the volume commitment delivered in a contract year can be carried over to the next contract year for purposes of calculating the natural gas deficiency. The Company paid approximately $2.8 million in processing and gathering fees under this agreement during the three months ended June 30, 2016 and $4.7 million during the six months ended June 30, 2016. The Company can elect to either sell the residue gas to the counterparty at the tailgate of its processing plant or have the counterparty deliver to the Company the residue gas in-kind to be sold to third parties downstream of the plant.

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 entered 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 $43.0 million at June 30, 2016.

The Company entered into an agreement in late 2015 with a third party for the engineering, procurement, construction and installation of a natural gas processing plant in the Rustler Breaks prospect area in Eddy County, New Mexico. The plant is expected to process a portion of the Company's natural gas produced from certain of its wells in the Delaware Basin, as well as third-party natural gas once the plant is completed and placed in service, which is scheduled to occur later in August 2016. At June 30, 2016, total remaining commitments under this contract were $4.6 million, and the Company made payments totaling $4.3 million during the three months ended June 30, 2016 and $17.8 million during the six months ended June 30, 2016.

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

NOTE 10 - COMMITMENTS AND CONTINGENCIES - Continued

At June 30, 2016, 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 $4.2 million at June 30, 2016, which the Company expects to incur within the next few months.

Legal Proceedings

The Company is a party to 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 11 - SUPPLEMENTAL DISCLOSURES

Accrued Liabilities

The following table summarizes the Company's current accrued liabilities at June 30, 2016 and December 31, 2015 (in thousands).

	June 30, 2016	December 31, 2015
Accrued evaluated and unproved and unevaluated property costs	$51,692	$ 54,586
Accrued support equipment and facilities costs	4,307	17,393
Accrued lease operating expenses	10,842	7,743
Accrued interest on debt	5,805	5,806
Accrued asset retirement obligations	61	254
Accrued partners' share of joint interest charges	3,936	4,565
Other	4,111	2,022
Total accrued liabilities	$80,754	$ 92,369

Supplemental Cash Flow Information

The following table provides supplemental disclosures of cash flow information for the six months ended June 30, 2016 and 2015 (in thousands).

	Six Months Ended June 30,	
	2016	2015
Cash paid for interest expense, net of amounts capitalized	$12,226	$2,263
Asset retirement obligations related to mineral properties	$2,511	$1,212
Asset retirement obligations related to support equipment and facilities	$75	$41
Decrease in liabilities for oil and natural gas properties capital expenditures	$(3,476)	$(9,909)
(Decrease) increase in liabilities for support equipment and facilities	$(11,565)	$3,859
Increase in liabilities for accrued cost to issue equity	$62	$—
Stock-based compensation expense recognized as liability	$88	$583
Transfer of inventory from oil and natural gas properties	$474	$456

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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 interim unaudited condensed consolidated financial statements and related notes thereto contained herein and in our Annual Report on Form 10-K for the year ended December 31, 2015 (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.

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 Quarterly 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,” “forecasted,” “hypothetical,” “intend,” “may,” “might,” “plan,” “potential,” “predict,” “project,” “should” or other similar wor not all forward- looking statements contain such identifying 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: general economic conditions, changes in oil, natural gas and natural gas liquids prices and the demand for oil, natural gas and natural gas liquids, the success of our drilling program, the timing of planned capital expenditures, sufficient cash flow from operations together with available borrowing capacity under our credit agreement, 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, our ability to integrate acquisitions, including the integration of Harvey E. Yates Company, with our business, weather and environmental conditions, 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;
- our ability to negotiate and consummate acquisition and divestiture opportunities;
- government regulation and taxation of the oil and natural gas industry;
- our marketing of oil and natural gas;
- our exploitation projects or property acquisitions;
- the integration of acquisitions, including the integration of Harvey E. Yates Company, with our business;

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- our ability to construct and operate midstream facilities;
- 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; and
- our plans, objectives, expectations and intentions contained in this Quarterly Report on Form 10-Q that are not historical.

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 Delaware Basin in Southeast New Mexico and West Texas. We also operate in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas.

Second Quarter and Year-to-Date Highlights

Quarterly oil equivalent and natural gas production results for the second quarter of 2016 were the best in our history. For the three months ended June 30, 2016, our total oil equivalent production was 2.55 million BOE and our average daily oil equivalent production was 28,022 BOE per day, of which 13,516 Bbl per day, or 48%, was oil and 87.0 MMcf per day, or 52%, was natural gas. Our total oil equivalent production of 2.55 million BOE for the three months ended June 30, 2016 increased 5% year-over-year from 2.42 million BOE for the three months ended June 30, 2015. For the six months ended June 30, 2016, our total oil equivalent production was 4.72 million BOE and our average daily oil equivalent production was 25,934 BOE per day, of which 12,495 Bbl per day, or 48%, was oil and 80.6 MMcf per day, or 52%, was natural gas. Our total oil equivalent production of 4.72 million BOE for the six months ended June 30, 2016 increased 4% year-over-year from 4.54 million BOE for the six months ended June 30, 2015.

During the second quarter of 2016, our oil and natural gas revenues were $69.3 million, a decrease of 21% from oil and natural gas revenues of $87.8 million during the second quarter of 2015. Our oil revenues and natural gas revenues decreased 23% and 14%, respectively, to approximately $52.7 million and $16.6 million, respectively, primarily as a result of significantly lower oil and natural gas prices realized for the second quarter of 2016, as compared to $68.5 million and $19.3 million, respectively, for the second quarter of 2015. We realized weighted average oil and natural gas prices of $42.84 per Bbl and $2.10 per Mcf, respectively, in the second quarter of 2016, as compared to weighted average oil and natural gas prices of $54.37 per Bbl and $2.78 per Mcf, respectively, realized in the second quarter of 2015. In addition, our oil production decreased 2% to 1.23 million Bbl in the second quarter of 2016, as compared to 1.26 million Bbl produced in the second quarter of 2015. The decrease in oil production was primarily a result of declining oil production in the Eagle Ford shale where we have not drilled and completed any new operated wells since early in the second quarter of 2015, which offset increasing oil production from our ongoing delineation and development drilling in the Delaware Basin. The decrease in oil and natural gas revenues was somewhat mitigated by the 14% increase in our natural gas production to 7.9 Bcf in the second quarter of 2016, as compared to 7.0 Bcf in the second quarter of 2015. The increase in natural gas production was primarily a result of our ongoing delineation and development drilling in the Delaware Basin, which offset declining natural gas production in the Eagle Ford and

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Haynesville shales where we have significantly reduced our activity since late 2014 and early 2015. For the three months ended June 30, 2016, the net loss attributable to Matador Resources Company shareholders was $105.9 million, a decrease of 33% from the net loss attributable to Matador Resources Company shareholders of $157.1 million during the three months ended June 30, 2015. For the three months ended June 30, 2016, our Adjusted EBITDA was $39.0 million, a decrease of 42% from Adjusted EBITDA of $66.7 million during the three months ended June 30, 2015. 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 the second quarter of 2016, see "— Results of Operations" below.

During the six months ended June 30, 2016, our oil and natural gas revenues were $113.3 million, a decrease of 25% from oil and natural gas revenues of $150.3 million during the six months ended June 30, 2015. This decrease was attributable to a sharp decline in weighted average oil and natural gas prices to $36.43 per Bbl and $2.07 per Mcf, respectively, realized in the six months ended June 30, 2016 from weighted average oil and natural gas prices of $49.48 per Bbl and $2.80 per Mcf, respectively, realized in the six months ended June 30, 2015. The decrease in our oil and natural gas revenues was somewhat mitigated by the 8% increase in our natural gas production to 14.7 Bcf in the six months ended June 30, 2016, as compared to 13.6 Bcf in the six months ended June 30, 2015. Our oil production remained flat at 2.27 million Bbl for both the six months ended June 30, 2016 and 2015. The changes in oil and natural gas production were attributable to the same operations noted above for the three months ended June 30, 2016 and 2015. For the six months ended June 30, 2016, the net loss attributable to Matador Resources Company shareholders was $213.5 million, an increase of 3% from the net loss attributable to Matador Resources Company shareholders of $207.3 million during the six months ended June 30, 2015. For the six months ended June 30, 2016, our Adjusted EBITDA was $56.2 million, a decrease of 52% from Adjusted EBITDA of $116.8 million during the six months ended June 30, 2015. 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 the six months ended June 30, 2016, see "— Results of Operations" below.

During the second quarter of 2016, we operated three drilling rigs in the Delaware Basin. Two of these rigs were operating in the Rustler Breaks prospect area in Eddy County, New Mexico, and one was operating in the Wolf prospect area in Loving County, Texas. In mid-July, one of the rigs operating in the Rustler Breaks prospect area was moved to the Ranger/Arrowhead prospect area in the northern portion of our acreage position in Lea County, New Mexico to begin drilling a three-well program, with all three wells testing the Third Bone Spring sand. At August 3, 2016, we continued to operate three drilling rigs, with one rig operating in each of the Wolf, Rustler Breaks and Ranger/Arrowhead prospect areas.

During the second quarter of 2016, we began producing oil and natural gas from 22 gross (17.2 net) wells in the Delaware Basin, including 19 gross (16.4 net) operated and two gross (0.3 net) non-operated horizontal wells, in the Rustler Breaks and Wolf prospect areas. We also began producing oil and natural gas from one gross (0.5 net) vertical well at Rustler Breaks as part of a successful acreage-holding operation with our working interest partners. We completed and placed on production 11 gross (7.9 net) horizontal wells at Rustler Breaks during the second quarter of 2016, including nine gross (7.6 net) operated and two gross (0.3 net) non-operated wells. These nine gross operated horizontal wells included five Wolfcamp A-XY completions and four Wolfcamp B completions; both non-operated wells were also completed in the Wolfcamp B. In addition, we completed and placed on production 10 gross (8.8 net) operated horizontal wells at Wolf during the second quarter of 2016, including five Wolfcamp A-X, three Wolfcamp A-Y, one Wolfcamp A-Lower and one Second Bone Spring completions.

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 second quarter of 2016 was 14,525 BOE per day, consisting of 9,789 Bbl of oil per day and 28.4 MMcf of natural gas per day, a 2.3-fold increase from production of 6,187 BOE per day, consisting of 4,468 Bbl of oil per day and 10.3 MMcf of natural gas per day, in the second quarter of 2015. The Delaware Basin contributed approximately 72% of our daily oil production and approximately 33% of our daily natural gas production in the second quarter of 2016, as compared to

approximately 32% of our daily oil production and approximately 13% of our daily natural gas production in the second quarter of 2015.
At June 30, 2016, we had incurred $198.0 million, or approximately 61%, of our 2016 capital expenditure budget of $325.0 million. This was in line with our budgeted capital expenditures of $192.0 million in the first six months of 2016.
The five Wolfcamp A-XY wells completed and placed on production in the Rustler Breaks prospect area in the second quarter of 2016 were consistent with or better than the best Wolfcamp A-XY wells drilled by us in this prospect area to date. The Paul 25-24S-28E RB #221H well (Paul #221H) tested at the highest 24-hour initial potential flow rate of any Wolfcamp A-XY well we have drilled at Rustler Breaks—1,701 BOE per day (74% oil)—and early performance from this well indicates that it may be the best Wolfcamp A-XY well drilled to date at Rustler Breaks. During the second quarter of 2016, we tested our first two wells drilled in the deepest bench of the Wolfcamp B (Blair Shale) at Rustler Breaks. This is the third bench of the Wolfcamp B we have successfully tested at Rustler Breaks. These three target benches of the Wolfcamp B occur starting

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approximately 300 feet into the 1,000-foot thick Wolfcamp B interval at Rustler Breaks, and are each about 200 to 250 feet apart vertically.

The 24-hour initial potential flow rates from the two Wolfcamp B-Blair wells—the Jimmy Kone 05-24S-28E RB #228H and the Tiger 14-24S-28E RB #227H—were the two highest 24-hour test results we have reported in the Delaware Basin to date at 2,438 BOE per day and 1,812 BOE per day, respectively, at about 33% oil. These 24-hour initial potential test results compare favorably to those from other wells completed in the middle Wolfcamp B, the Tiger 14-24S-28E RB #224H and Janie Conner 13-24S-28E RB #224H wells, which had 24-hour initial potential rates of 1,533 BOE per day (43% oil) and 1,703 BOE per day (59% oil), respectively. The oil volumes from these lower Wolfcamp B completions were reasonably comparable to those in the middle Wolfcamp B, while the natural gas volumes were higher.

In the Wolf prospect area, we are pleased with the test results observed from the Dorothy White 82-TTT-B33 WF #123H well (Dorothy White #123H), a Second Bone Spring completion. Both this well and the Dick Jay 92-TTT-B01 WF #124H well, another Second Bone Spring completion reported in our Quarterly Report on Form 10-Q for the three months ended March 31, 2016, are significant improvements over our first Second Bone Spring well drilled in the Wolf prospect area. In particular, the recently-completed Dorothy White #123H well has continued to perform well in its first two months of production, having averaged approximately 450 Bbl of oil per day and 1.8 MMcf of natural gas per day (60% oil) during that period.

Our operational efficiencies continue to improve at Rustler Breaks and throughout our Delaware Basin drilling and completions program. Through the first half of 2016, we have further reduced our average drilling time as compared to 2014 and 2015 in the Wolfcamp A-XY by approximately 28% and 12%, respectively, and in the Wolfcamp B by approximately 47% and 32%, respectively. Our fastest-drilled Wolfcamp A-XY well, the Paul #221H well, was drilled in 13.8 days from spud to a total depth of 14,468 feet, a decrease of 44% from the average drilling time in late 2014, and our fastest-drilled Wolfcamp B well, the B. Banker 33-23S-28E RB #221H well, was drilled in 17.5 days from spud to a total depth of 15,151 feet, a decrease of 58% from the average drilling time in 2014. These drilling times of 13.8 and 17.5 days are faster than our 2016 drilling objectives of 14 days for the Wolfcamp A-XY and 18 days for the Wolfcamp B, respectively, from spud to total depth, which we had targeted to achieve by year-end 2016. We delivered faster drilling times as a result of our increased knowledge of the geology and our experience with drilling in the Rustler Breaks area, as well as improvements in drilling the curve between the vertical and horizontal portions of these wells and continued applications of improved drill bit and bottomhole assembly technologies.

Due in part to these improvements in drilling times, continued innovation by our technical staff and lower-than-anticipated stimulation costs, the costs associated with recent Wolfcamp A-XY and Wolfcamp B wells at Rustler Breaks continued to decline and were among the lowest we have achieved to date. We have been able to drill, complete and equip several wells in the Wolfcamp A-XY for just under $5 million on each well and in the Wolfcamp B for approximately $5.5 million each. These costs were just under or in line with our targets for year-end 2016 for the Wolfcamp A-XY and the Wolfcamp B, all while maintaining or increasing the size and effectiveness of the completion design.

Operational efficiencies continued to improve in the Wolf prospect area as well. Through the first half of 2016, we have further reduced our average drilling time in the Wolfcamp A-X and A-Y by approximately 57% and 24% as compared to 2014 and 2015, respectively, and in the Second Bone Spring by approximately 42% as compared to our first well drilled in the Second Bone Spring in 2015. Our fastest-drilled Wolfcamp A well, the Dorothy White 82-TTT-B33 #203H well, was drilled in 17.3 days from spud to a total depth of 15,550 feet, a decrease of 60% from the 2014 average drilling time and faster than our Wolfcamp A drilling objective of 18 days from spud to total depth that we had targeted to achieve by year-end 2016 at Wolf. The Dorothy White #123H well was drilled in approximately 12.6 days from spud to total depth, with drilling times being faster than our 2016 year-end drilling target of 13 days for our Second Bone Spring wells. In the Dorothy White #123H well, our drilling engineers were also able to eliminate a second intermediate casing string typically used when drilling the Second Bone Spring in this area. Not only did eliminating this casing string save approximately $650,000 in well costs on each well, but it also provides for larger casing to be set through the lateral, thereby reducing hydraulic horsepower costs during fracturing operations and enhancing the number of artificial lift options available in the future. Total cost to drill, complete and equip the Dorothy White #123H well was just over $4 million, but we estimate that we should be able to drill, complete and equip Second Bone Spring wells in this area for under $4 million in the near future.

Well costs associated with recent Wolfcamp A-X and A-Y wells drilled and completed in the Wolf prospect area also continued to decline. Costs to drill, complete and equip recent Wolfcamp A wells have ranged between $5 million and $6 million, with a number of these wells at or below our 2016 year-end target of $5.5 million. As at Rustler Breaks, we attribute these cost savings to the innovation and use of new technologies by our drilling, completions and production teams, as well as lower-than-expected stimulation costs.

At December 31, 2015, we held approximately 157,100 gross (88,800 net) acres in Southeast New Mexico and West Texas, primarily in the Delaware Basin in Lea and Eddy Counties, New Mexico and Loving County, Texas. Between January 1, 2016 and August 3, 2016, we added approximately 6,400 gross (3,100 net) acres in the Delaware Basin. As a result,

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at August 3, 2016 our total acreage position in Southeast New Mexico and West Texas was approximately 161,900 gross (91,100 net) acres, almost all of which was in the Delaware Basin. During the second quarter of 2016, we also acquired mineral ownership in approximately 7,900 gross (1,700 net) acres in our Rustler Breaks, Wolf and Ranger/Arrowhead prospect areas. We plan to continue our leasing and acquisition efforts in the Delaware Basin during the remainder of 2016 and may also consider acquiring acreage in the Eagle Ford shale and Haynesville shale as strategic opportunities are identified.

Estimated Proved Reserves

The following table sets forth our estimated total proved oil and natural gas reserves at June 30, 2016, December 31, 2015 and June 30, 2015. 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 Delaware Basin and the Eagle Ford shale, 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.

	June 30, 2016	December 31, 2015	June 30, 2015
Estimated Proved Reserves Data: (1) (2)			
Estimated proved reserves:			
Oil (MBbl)(3)	52,337	45,644	40,594
Natural Gas (Bcf)(4)	258.7	236.9	278.6
Total (MBOE)(5)	95,457	85,127	87,027
Estimated proved developed reserves:			
Oil (MBbl)(3)	19,913	17,129	17,514
Natural Gas (Bcf)(4)	114.4	101.4	100.2
Total (MBOE)(5)	38,978	34,037	34,217
Percent developed	40.8 %	40.0 %	39.3 %
Estimated proved undeveloped reserves:			
Oil (MBbl)(3)	32,424	28,515	23,080
Natural Gas (Bcf)(4)	144.3	135.5	178.4
Total (MBOE)(5)	56,479	51,090	52,810
Standardized Measure(6) (in millions)	$468.3	$529.2	$864.1
PV-10(7) (in millions)	$473.2	$541.6	$942.8

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

(2) Our estimated proved reserves, Standardized Measure and PV-10 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 July 2015 through June 2016 were $39.63 per Bbl for oil and $2.24 per MMBtu for natural gas, for the period from January 2015 through December 2015 were $46.79 per Bbl for oil and $2.59 per MMBtu for natural gas and for the period from July 2014 through June 2015 were $68.17 per Bbl for oil and $3.39 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.

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(6) 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.

(7) 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 June 30, 2016, December 31, 2015 and June 30, 2015 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 June 30, 2016, December 31, 2015 and June 30, 2015 were, in millions, $4.9, $12.4 and $78.7, respectively.

At June 30, 2016, our estimated total proved oil and natural gas reserves were 95.5 million BOE, an all-time high, including 52.3 million Bbl of oil and 258.7 Bcf of natural gas, with a Standardized Measure of $468.3 million and a PV-10, a non-GAAP financial measure, of $473.2 million. At December 31, 2015, our estimated total proved oil and natural gas reserves were 85.1 million BOE, including 45.6 million Bbl of oil and 236.9 Bcf of natural gas, and at June 30, 2015, our estimated total proved oil and natural gas reserves were 87.0 million BOE, including 40.6 million Bbl of oil and 278.6 Bcf of natural gas. Our proved oil reserves of 52.3 million Bbl at June 30, 2016, also an all-time high, increased 15%, as compared to 45.6 million Bbl at December 31, 2015, and increased 29%, as compared to 40.6 million Bbl at June 30, 2015. At June 30, 2016, approximately 41% of our total proved reserves were proved developed reserves, 55% of our total proved reserves were oil and 45% of our total proved reserves were natural gas. Primarily as a result of the continued decline in commodity prices used to estimate proved reserves at June 30, 2016, certain of our proved undeveloped reserves were reclassified to contingent resources and are no longer considered proved reserves under applicable SEC guidelines.

As a result of our drilling, completion and delineation activities in West Texas and Southeast New Mexico since 2014, our Delaware Basin oil and natural gas reserves continue to become a more significant component of our total oil and natural gas reserves. Our estimated Delaware Basin proved oil and natural gas reserves have increased approximately two-fold from 33.9 million BOE at June 30, 2015, or 39% of our total proved oil and natural gas reserves, including 21.9 million Bbl of oil and 71.4 Bcf of natural gas, to 66.2 million BOE, or 69% of our total proved oil and natural gas reserves, including 40.3 million Bbl of oil and 155.3 Bcf of natural gas, at June 30, 2016.

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

There have been no changes to our critical accounting policies and estimates from those set forth in the Annual Report.

Recent Accounting Pronouncements

See Note 2 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for the adoption of a new accounting pronouncement in the second quarter of 2016 and for a summary of recent accounting pronouncements that we believe may have an impact on our financial statements upon adoption.

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Results of Operations

Revenues

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Operating Data:				
Revenues (in thousands):[1]				
Oil	$52,691	$68,515	$82,849	$112,251
Natural gas	16,645	19,333	30,413	38,063
Total oil and natural gas revenues	69,336	87,848	113,262	150,314
Realized gain on derivatives	2,465	13,780	9,528	32,285
Unrealized loss on derivatives	(26,625)	(23,532)	(33,464)	(32,090)
Total revenues	$45,176	$78,096	$89,326	$150,509
Net Production Volumes:[1]				
Oil (MBbl)[2]	1,230	1,260	2,274	2,269
Natural gas (Bcf)[3]	7.9	7.0	14.7	13.6
Total oil equivalent (MBOE)[4]	2,550	2,421	4,720	4,537
Average daily production (BOE/d)[5]	28,022	26,601	25,934	25,066
Average Sales Prices:				
Oil, with realized derivatives (per Bbl)	$43.29	$62.72	$39.08	$60.48
Oil, without realized derivatives (per Bbl)	$42.84	$54.37	$36.43	$49.48
Natural gas, with realized derivatives (per Mcf)	$2.34	$3.24	$2.31	$3.34
Natural gas, without realized derivatives (per Mcf)	$2.10	$2.78	$2.07	$2.80

(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 June 30, 2016 as Compared to Three Months Ended June 30, 2015

Oil and natural gas revenues. Our oil and natural gas revenues decreased $18.5 million to $69.3 million, or a decrease of 21%, for the three months ended June 30, 2016, as compared to $87.8 million for the three months ended June 30, 2015. Our oil revenues decreased $15.8 million, or 23%, to $52.7 million for the three months ended June 30, 2016, as compared to $68.5 million for the three months ended June 30, 2015. The decrease in oil revenues resulted primarily from a lower weighted average oil price realized for the three months ended June 30, 2016 of $42.84 per Bbl, as compared to $54.37 per Bbl realized for the three months ended June 30, 2015. In addition, our oil production decreased 2% to 1.23 million Bbl of oil for the three months ended June 30, 2016, or about 13,516 Bbl of oil per day, as compared to just over 1.26 million Bbl of oil, or about 13,847 Bbl of oil per day, for the three months ended June 30, 2015. This small decrease in oil production was primarily a result of declining oil production in the Eagle Ford shale where we have not drilled and completed any new operated wells since early in the second quarter of 2015. We reduced our drilling program from five operated rigs in the first quarter of 2015 to two operated rigs in the second quarter of 2015, as compared to the three operated rigs as of August 3, 2016. Our natural gas revenues decreased by $2.7 million, or 14%, to $16.6 million for the three months ended June 30, 2016, as compared to $19.3 million for the three months ended June 30, 2015. The decrease in natural gas revenues resulted from a lower weighted average natural gas price realized for the three months ended June 30, 2016 of $2.10 per Mcf, as compared to $2.78 per Mcf realized for the three months ended June 30, 2015. The lower weighted average natural gas price was partially mitigated by the 14% increase in our natural gas production to 7.9 Bcf for the three months ended June 30, 2016, as compared to 7.0 Bcf for the three months ended June 30, 2015. The increased natural gas production was primarily attributable to our ongoing delineation and development drilling in the Delaware Basin, which offset declining natural gas production in the Eagle Ford and Haynesville shales where we have significantly reduced our activity since late 2014 and early 2015.

Realized gain on derivatives. Our realized gain on derivatives was $2.5 million for the three months ended June 30, 2016, as compared to a realized gain of $13.8 million for the three months ended June 30, 2015. We realized gains of $0.6 million and $1.9 million from our oil and natural gas derivative contracts, respectively, for the three months ended June 30, 2016. For the three months ended June 30, 2015, we realized a net gain of $10.5 million, $2.7 million and $0.5 million attributable to our oil, natural gas and natural gas liquids (“NGL”) derivative contracts, respectively. The realized gains on our oil and natural gas derivative contracts during the respective periods were attributable to commodity prices being below the floor prices of the majority of our oil and natural gas costless collar contracts for the three months ended June 30, 2016 and 2015. The realized gain on our NGL derivative contracts during the three months ended June 30, 2015 resulted from NGL prices that were lower than the fixed prices of our NGL swap contracts; we had no open NGL derivative contracts in 2016. The average floor prices of our oil costless collar contracts were $42.48 per Bbl and $70.38 per Bbl for the three months ended June 30, 2016 and 2015, respectively. The average ceiling prices of our oil costless collar contracts were $61.16 per Bbl and $87.72 per Bbl for the three months ended June 30, 2016 and 2015, respectively. During the second quarter of 2016, our natural gas costless collar contracts had average floor and ceiling prices of $2.60 per MMBtu and $3.53 per MMBtu, respectively, as compared to $3.26 per MMBtu and $3.94 per MMBtu, respectively, during the second quarter of 2015. Our total oil and natural gas volumes hedged for the three months ended June 30, 2016 were 1% higher and 31% lower, respectively, than the total oil and natural gas volumes hedged for the same period in 2015.

Unrealized loss on derivatives. Our unrealized loss on derivatives was $26.6 million for the three months ended June 30, 2016, as compared to an unrealized loss of $23.5 million for the three months ended June 30, 2015. During the three months ended June 30, 2016, the aggregate net fair value of our open oil and natural gas derivative contracts decreased to a liability of $17.2 million from an asset of $9.4 million at March 31, 2016, resulting in an unrealized loss on derivatives of $26.6 million for the three months ended June 30, 2016. During the three months ended June 30, 2016, the net fair value of our open oil derivative contracts decreased by $19.3 million due primarily to the increase in oil prices during the three months ended June 30, 2016, and the net fair value of our open natural gas derivative contracts decreased by $7.3 million due primarily to the increase in natural gas prices during the three months ended June 30, 2016. During the three months ended June 30, 2015, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts decreased to $23.5 million from $47.0 million at March 31, 2015, resulting in an unrealized loss on derivatives of $23.5 million for the three months ended June 30, 2015.

Six Months Ended June 30, 2016 as Compared to Six Months Ended June 30, 2015

Oil and natural gas revenues. Our oil and natural gas revenues decreased by approximately $37.1 million, or 25%, to approximately $113.3 million for the six months ended June 30, 2016, as compared to $150.3 million for the six months ended June 30, 2015. Our oil revenues decreased by 26% to $82.8 million for the six months ended June 30, 2016, as compared to $112.3 million for the six months ended June 30, 2015. The decrease in oil revenues resulted from a lower weighted average oil price realized in the six months ended June 30, 2016 of $36.43 per Bbl, as compared to $49.48 per Bbl realized for the six months ended June 30, 2015. Our oil production remained essentially flat at 2.27 million Bbl of oil in the six months ended June 30, 2016, or about 12,495 Bbl of oil per day, as compared to 2.27 million Bbl of oil, or about 12,534 Bbl of oil per day, in the six months ended June 30, 2015. Increasing oil production due to our ongoing delineation and development drilling in the Delaware Basin offset declining oil production from the Eagle Ford shale during this period. Our natural gas revenues decreased by $7.7 million, or 20%, to $30.4 million for the six months ended June 30, 2016, as compared to $38.1 million for the six months ended June 30, 2015. Our natural gas production increased by 8% to 14.7 Bcf for the six months ended June 30, 2016, as compared to 13.6 Bcf for the six months ended June 30, 2015. The increase in natural gas production was primarily attributable to increased natural gas production associated with our operations in the Delaware Basin and new, non-operated Haynesville shale wells completed and placed on production on our Elm Grove properties in Northwest Louisiana during the latter half of 2015 and into 2016. This production increase was largely offset by a lower weighted average natural gas price of $2.07 per Mcf realized during the six months ended June 30, 2016, as compared to a weighted average natural gas price of $2.80 per Mcf realized during the six months ended June 30, 2015, and declining natural gas production in the Eagle Ford shale where we have not drilled and completed any new operated wells since early in the second quarter of 2015.

Realized gain on derivatives. We realized a gain on derivatives of approximately $9.5 million for the six months ended June 30, 2016, as compared to a gain of approximately $32.3 million for the six months ended June 30, 2015. For the six months ended June 30, 2016, we realized net gains of approximately $6.0 million and $3.5 million attributable to our oil and natural gas derivative contracts, respectively. For the six months ended June 30, 2015, we realized net gains of approximately $25.0 million, $6.3 million and $1.0 million attributable to our oil, natural gas and NGL derivative contracts, respectively. The net gain realized from our derivative contracts for the six months ended June 30, 2016 resulted from oil and natural gas prices that were below the floor prices of the majority of our oil and natural gas derivative contracts. During the six months ended June 30, 2016, our natural gas costless collar contracts had average floor and ceiling prices of $2.62 per MMBtu and $3.56 per MMBtu, respectively, as compared to $3.50 per MMBtu and $4.31 per MMBtu, respectively, for the six months ended June 30, 2015. The average floor prices of our oil costless collar contracts were $43.58 per Bbl and $75.20 per Bbl for the six months ended June 30, 2016 and 2015, respectively. The average ceiling prices of our oil costless collar contracts were $64.13 per Bbl and $92.31 per Bbl for the six months ended June 30, 2016 and 2015, respectively. Our total oil and natural gas volumes

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hedged for the six months ended June 30, 2016 were 7% higher and 37% lower, respectively, than the total oil and natural gas volumes hedged for the same period in 2015.

Unrealized loss on derivatives. Our unrealized loss on derivatives was approximately $33.5 million for the six months ended June 30, 2016, as compared to an unrealized loss of approximately $32.1 million for the six months ended June 30, 2015. During the period from December 31, 2015 through June 30, 2016, the aggregate net fair value of our open oil and natural gas derivative contracts decreased from an asset of approximately $16.3 million to a liability of approximately $17.2 million, resulting in an unrealized loss on derivatives of approximately $33.5 million for the six months ended June 30, 2016. This loss is primarily attributable to the increase in oil and natural gas prices during the six months ended June 30, 2016, particularly during the second quarter. During the period from December 31, 2014 through June 30, 2015, the aggregate net fair value of our open oil, natural gas and NGL derivative contracts decreased from $55.5 million to $23.5 million, resulting in an unrealized loss on derivatives of $32.1 million for the six months ended June 30, 2015.

Expenses

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands, except expenses per BOE)	2016	2015	2016	2015
Expenses:				
Production taxes and marketing	$10,556	$10,258	$18,459	$17,308
Lease operating	13,174	14,950	28,664	27,996
Depletion, depreciation and amortization	31,248	51,768	60,170	98,239
Accretion of asset retirement obligations	289	132	552	244
Full-cost ceiling impairment	78,171	229,026	158,633	296,153
General and administrative	13,197	12,961	26,360	26,372
Total expenses	$146,635	$319,095	$292,838	$466,312
Operating loss	$(101,459)	$(240,999)	$(203,512)	$(315,803)
Other income (expense):				
Net gain (loss) on asset sales and inventory impairment	$1,002	$—	$2,067	$(97)
Interest expense	(6,167)	(5,869)	(13,365)	(7,939)
Interest and other income	877	502	1,396	886
Total other expense	$(4,288)	$(5,367)	$(9,902)	$(7,150)
Loss before income taxes	$(105,747)	$(246,366)	$(213,414)	$(322,953)
Total income tax benefit	—	(89,350)	—	(115,740)
Net income attributable to non-controlling interest in subsidiaries	(106)	(75)	(93)	(111)
Net loss attributable to Matador Resources Company shareholders	$(105,853)	$(157,091)	$(213,507)	$(207,324)
Expenses per BOE:				
Production taxes and marketing	$4.14	$4.24	$3.91	$3.81
Lease operating	$5.17	$6.18	$6.07	$6.17
Depletion, depreciation and amortization	$12.25	$21.39	$12.75	$21.65
General and administrative	$5.18	$5.35	$5.58	$5.81

Three Months Ended June 30, 2016 as Compared to Three Months Ended June 30, 2015

Production taxes and marketing. Our production taxes and marketing expenses increased by $0.3 million to $10.6 million, or an increase of 3%, for the three months ended June 30, 2016, as compared to $10.3 million for the three months ended June 30, 2015. On a unit-of-production basis, our production taxes and marketing expenses decreased by 2% to $4.14 per BOE for the three months ended June 30, 2016, as compared to $4.24 per BOE for the three months ended June 30, 2015. The increase in production taxes and marketing expenses was primarily attributable to higher natural gas marketing and processing expenses of $6.7 million for the three months ended June 30, 2016, as compared to natural gas marketing and processing expenses of $6.1 million for the three months ended June 30, 2015.

This increase of $0.6 million was primarily due to the increase in natural gas production in the Delaware Basin as a percentage of our total natural gas production for the three months ended June 30, 2016, as compared to the three months ended June 30, 2015. Natural gas marketing and processing expenses are higher in the Delaware Basin, as compared to the Eagle Ford shale, as the natural gas gathering and processing infrastructure

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has yet to meet the demand for these services due to the increased drilling activity in the Delaware Basin over the last few years. We anticipate that we will incur lower marketing and processing expenses for most of the natural gas produced in Eddy County, New Mexico once the cryogenic natural gas processing plant we are constructing and installing in the Rustler Breaks prospect area is completed and operational. On an absolute basis, our production taxes decreased by $0.3 million to $3.9 million for the three months ended June 30, 2016, as compared to $4.2 million for the three months ended June 30, 2015, primarily due to the 21% decrease in oil and natural gas revenues in the second quarter of 2016 as compared to the second quarter of 2015.

Lease operating expenses. Our lease operating expenses decreased by $1.8 million to $13.2 million, or a decrease of 12%, for the three months ended June 30, 2016, as compared to $15.0 million for the three months ended June 30, 2015. Our lease operating expenses per unit of production decreased 16% to $5.17 per BOE for the three months ended June 30, 2016, as compared to $6.18 per BOE for the three months ended June 30, 2015. Our total oil equivalent production increased 5% to approximately 2.55 million BOE for the three months ended June 30, 2016 from approximately 2.42 million BOE for the three months ended June 30, 2015. The decrease achieved in lease operating expenses on a unit-of-production basis was attributable to several key factors, including (i) decreased field supervisory costs as a number of third-party contractors became full-time employees during the second quarter of 2016, (ii) decreased supervisory and chemical costs associated with our Eagle Ford operations and (iii) increased oil equivalent production as compared to the same period in 2015.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses decreased by $20.5 million to $31.2 million, or a decrease of 40%, for the three months ended June 30, 2016, as compared to $51.8 million for the three months ended June 30, 2015. On a unit-of-production basis, our depletion, depreciation and amortization expenses decreased to $12.25 per BOE for the three months ended June 30, 2016, or a decrease of 43%, from $21.39 per BOE for the three months ended June 30, 2015. The decrease in the depletion, depreciation and amortization expenses was primarily attributable to the decrease in unamortized property costs resulting from the full-cost ceiling impairments recorded in 2015 and 2016, as well as the 10% increase in our total estimated proved oil and natural gas reserves between the two periods. This increase in total proved oil and natural gas reserves was primarily attributable to the continued delineation and development of our acreage in the Delaware Basin.

Full-cost ceiling impairment. At June 30, 2016, the net capitalized costs of our oil and natural gas properties exceeded the full-cost ceiling by $78.2 million. As a result, we recorded an impairment charge of $78.2 million to the net capitalized costs of our oil and natural gas properties. This full-cost ceiling impairment is reflected in our interim unaudited condensed consolidated statement of operations for the three months ended June 30, 2016. We also recorded an impairment charge of $229.0 million to the net capitalized costs of our oil and natural gas properties for the three months ended June 30, 2015.

In determining the full-cost ceiling impairment at June 30, 2016, we estimated the PV-10 of our total proved oil and natural gas reserves using the unweighted arithmetic average of oil and natural gas prices as of the first day of each month for the trailing 12-month period ended June 30, 2016 as required under the guidelines established by the SEC, which were $39.63 per Bbl and $2.24 per MMBtu, respectively. If the unweighted arithmetic average of oil and natural gas prices as of the first day of each month for the trailing 12-month period ended June 30, 2016 had been $37.90 per Bbl and $2.26 per MMBtu, respectively, while all other factors remained constant, our full-cost ceiling would have been reduced by an additional $48.5 million on a pro forma basis. The aforementioned pro forma prices, as estimated for the twelve month period October 2015 through September 2016, were calculated using a 12-month unweighted arithmetic average of oil and natural gas prices, which included the oil and natural gas prices on the first day of the month for the 11 months ended August 2016, with the price for August 2016 being held constant for September 2016. This pro forma increase in the excess of our net capitalized costs above the full-cost ceiling is attributable to a pro forma reduction of $48.5 million in the PV-10 of our total proved oil and natural gas reserves, including a pro forma decrease in our estimated total proved reserves to 94.9 million BOE, or a reduction of approximately 1%, from our reported estimated proved reserves of 95.5 million BOE at June 30, 2016, primarily attributable to certain proved undeveloped locations that would no longer be classified as proved undeveloped reserves using the pro forma prices. This calculation of the impact of lower commodity prices on our estimated total proved oil and natural gas reserves and our full-cost ceiling was prepared based on the presumption that all other inputs and assumptions are held constant with the exception of oil and natural gas prices. Therefore, this calculation strictly isolates the impact of commodity prices on our full-cost ceiling and proved reserves. The impact of prices is only one of several variables in the estimation of our proved reserves and full-cost ceiling and other factors could have a significant impact on our future proved reserves and the present value of future cash flows. The other factors that impact future estimates of proved reserves include, but are not limited to, extensions and discoveries, acquisitions of proved reserves, changes in drilling and completion and operating costs, drilling results, revisions due to well performance and other factors, changes in development plans and production, among others. There are numerous uncertainties inherent in the estimation of proved oil and natural gas reserves and accounting for oil and natural gas properties in subsequent periods and this pro forma estimate should not be construed as indicative of our development plans or future results.

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General and administrative. Our general and administrative expenses increased by $0.2 million to $13.2 million, or an increase of 2%, for the three months ended June 30, 2016, as compared to $13.0 million for the three months ended June 30, 2015. This increase is primarily attributable to increased payroll and related expenses associated with additional employees joining the Company between the respective periods. General and administrative expenses also included non-cash stock-based compensation expense of $3.3 million and $2.8 million for the three months ended June 30, 2016 and 2015, respectively. The decrease in our general and administrative expenses on a unit-of-production basis to $5.18 per BOE for the three months ended June 30, 2016, as compared to $5.35 per BOE for the three months ended June 30, 2015, was also attributable to the 5% increase in total oil equivalent production between the respective periods.

Net gain (loss) on asset sales and inventory impairment. For the three months ended June 30, 2016, we recognized $1.0 million of the deferred gain on the sale of certain natural gas gathering and processing assets in Loving County, Texas that occurred in the fourth quarter of 2015.

Interest expense. For the three months ended June 30, 2016, we incurred total interest expense of $7.9 million. We capitalized $1.7 million of our interest expense on certain qualifying projects for the three months ended June 30, 2016 and expensed the remaining $6.2 million. For the three months ended June 30, 2015, we incurred total interest expense of $7.2 million. We capitalized $1.3 million of our interest expense on certain qualifying projects for the three months ended June 30, 2015 and expensed the remaining $5.9 million to operations. The increase in total interest expense is attributable to an increase in the average effective interest rate between comparable periods due to the issuance of our 6.875% senior notes due 2023 (the "Notes") in April 2015. In late April 2015, we used a portion of the net proceeds from the issuance of the Notes and our April 2015 equity offering to repay all outstanding borrowings under our Third Amended and Restated Revolving Credit Agreement (the "Credit Agreement"), which had an effective interest rate of 2.9% for the three months ended June 30, 2015. At June 30, 2016, we had no borrowings outstanding and $0.6 million in letters of credit outstanding under our Credit Agreement and $400.0 million in outstanding Notes.

Total income tax benefit. Our deferred tax assets exceed our deferred tax liabilities due to the deferred tax assets generated by the full-cost ceiling impairment charges recorded; as a result, we established a valuation allowance against most of the deferred tax assets beginning in the third quarter of 2015. We retain a full valuation allowance at June 30, 2016 due to uncertainties regarding the future realization of our deferred tax assets. Total income tax expense for the three months ended June 30, 2015 differed from amounts computed by applying the U.S. federal statutory tax rate to loss before income taxes due primarily to state tax apportionments and nondeductible expenses.

Six Months Ended June 30, 2016 as Compared to Six Months Ended June 30, 2015

Production taxes and marketing. Our production taxes and marketing expenses increased by approximately $1.2 million to approximately $18.5 million, or an increase of approximately 7%, for the six months ended June 30, 2016, as compared to $17.3 million for the six months ended June 30, 2015, in part due to our increased oil and natural gas production between the respective periods. On a unit-of-production basis, our production taxes and marketing expenses increased by 3% to $3.91 per BOE for the six months ended June 30, 2016, as compared to $3.81 per BOE for the six months ended June 30, 2015. The increase in our production taxes and marketing expenses on an absolute basis was primarily attributable to higher natural gas marketing expenses of $12.4 million for the six months ended June 30, 2016, as compared to natural gas marketing expenses of $10.5 million for the three months ended June 30, 2015, due to the 8% increase in natural gas production to 14.7 Bcf during the six months ended June 30, 2016, as compared to 13.6 Bcf of natural gas production for the six months ended June 30, 2015. Our production taxes decreased for the six months ended June 30, 2016 by $0.7 million to $6.1 million, as compared to $6.8 million for the six months ended June 30, 2015, primarily due to the 26% decrease in oil revenues during the six months ended June 30, 2016, as compared to the three months ended June 30, 2015.

Lease operating expenses. Our lease operating expenses increased by approximately $0.7 million, or an increase of 2%, to $28.7 million for the six months ended June 30, 2016, as compared to $28.0 million for the six months ended June 30, 2015. Our lease operating expenses per unit of production decreased 2% to $6.07 per BOE for the six months ended June 30, 2016, as compared to $6.17 per BOE for the six months ended June 30, 2015. Between these respective periods, our total oil equivalent production increased approximately 4% to 4.72 million BOE from 4.54 million BOE. The decrease achieved in lease operating expenses on a unit-of-production basis was primarily attributable to increased oil equivalent production as compared to the same period in 2015.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses decreased by $38.1 million to $60.2 million, or a decrease of 39%, for the six months ended June 30, 2016, as compared to $98.2 million for the six months ended June 30, 2015. On a unit-of-production basis, our depletion, depreciation and amortization expenses decreased to $12.75 per BOE for the six months ended June 30, 2016, or a decrease of about 41%, from $21.65 per BOE for the six months ended June 30, 2015. The decrease in both the total and the per-unit-of-production depletion, depreciation and amortization expenses resulted from higher estimated total proved reserves of 95.5 million BOE, or a 10% increase, at June 30, 2016, as compared to estimated total proved reserves of 87.0 million BOE at June 30, 2015, as well as the decrease in unamortized property costs resulting from the full-cost ceiling impairments previously recorded in 2015 and 2016. This increase in total proved oil and natural gas reserves was primarily attributable to the continued delineation and development of our acreage in the Delaware Basin.

Full-cost ceiling impairment. At June 30, 2016, the net capitalized costs of our oil and natural gas properties exceeded the cost center ceiling by $78.2 million. At March 31, 2016, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $80.5 million. As a result, we recorded an impairment charge of $158.6 million to the net capitalized costs of our oil and natural gas properties for the six months ended June 30, 2016. At March 31, 2015, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $67.1 million. At June 30, 2015, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $229.0 million. As a result, we recorded an impairment charge of $296.2 million to the net capitalized costs of our oil and natural gas properties for the six months ended June 30, 2015.

General and administrative. Our general and administrative expenses remained flat at $26.4 million for both the six months ended June 30, 2016 and 2015. On a unit-of-production basis, our general and administrative expenses decreased by 4% to $5.58 per BOE for the six months ended June 30, 2016, as compared to $5.81 per BOE for the six months ended June 30, 2015, as a result of our increased oil equivalent production between the respective periods.

Net gain (loss) on asset sales and inventory impairment. For the six months ended June 30, 2016, we recognized $2.1 million of the deferred gain on the sale of certain natural gas gathering and processing assets in Loving County, Texas that occurred in the fourth quarter of 2015.

Interest expense. For the six months ended June 30, 2016, we incurred total interest expense of approximately $15.6 million. We capitalized approximately $2.2 million of our interest expense on certain qualifying projects for the six months ended June 30, 2016 and expensed the remaining $13.4 million. For the six months ended June 30, 2015, we incurred total interest expense of approximately $10.2 million. We capitalized approximately $2.3 million of our interest expense on certain qualifying projects for the six months ended June 30, 2015 and expensed the remaining $7.9 million. The increase in total interest expense was attributable to an increase in the average effective interest rate between comparable periods due to the issuance of the Notes in April 2015. In late April 2015, we used a portion of the net proceeds from the issuance of the Notes and our April 2015 equity offering to repay all outstanding borrowings under our Credit Agreement.

Total income tax benefit. Our deferred tax assets exceed our deferred tax liabilities due to the deferred tax assets generated by the full-cost ceiling impairment charges recorded; as a result, we established a valuation allowance against most of the deferred tax assets beginning in the third quarter of 2015. We retain a full valuation allowance at June 30, 2016 due to uncertainties regarding the future realization of our deferred tax assets. Total income tax expense for the six months ended June 30, 2015 differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due primarily to state tax apportionments and nondeductible expenses.

Liquidity and Capital Resources

Our primary use of capital has been, and we expect will continue to be during the remainder of 2016 and for the foreseeable future, for the acquisition, exploration and development of oil and natural gas properties and for related midstream investments. Excluding any possible significant acquisitions, we expect to fund our capital expenditure requirements through the remainder of 2016 and into 2017 through a combination of cash on hand, the proceeds from our March 2016 equity offering, operating cash flows and borrowings under our Credit Agreement (assuming availability under our borrowing base). We continually evaluate other capital sources, including borrowings under additional credit arrangements, potential joint ventures, the sale of midstream or other assets or acreage and potential issuances of equity, debt or convertible securities, none of which may be available. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital and to generate operating cash flows.

At June 30, 2016, we had cash totaling $40.9 million and the borrowing base under our Credit Agreement was $300.0 million. At June 30, 2016 and August 3, 2016, we had no borrowings outstanding, $0.6 million and $0.8 million in outstanding letters of credit pursuant to our Credit Agreement, respectively, and $400.0 million of outstanding Notes.

As of August 3, 2016, we anticipated investing approximately $325.0 million in capital for acquisition, exploration and development activities in 2016. We incurred total capital expenditures of approximately $198.0 million during the first six months of 2016, which was in line with our budgeted capital expenditures of $192.0 million. Our 2016 capital expenditures may be adjusted as business conditions warrant, as evidenced by the substantial reduction in our 2016 capital expenditure budget, as compared to our 2015 capital spending. While we have budgeted $325.0 million in capital expenditures for 2016, the amount, timing and allocation of our capital expenditures is largely discretionary and within our control.

The aggregate amount of capital we will expend may fluctuate materially based on market conditions, the actual costs to drill, complete and place on production operated or non-operated wells, our drilling results, the actual costs of our midstream

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activities, other opportunities that may become available to us and our ability to obtain capital. When oil or natural gas prices decline, as oil and natural gas prices have done since mid-2014, or costs increase significantly, we have the flexibility to defer a significant portion of our capital expenditures until later periods to conserve cash or to focus on projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling, completion and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in our exploration and development activities, contractual obligations, drilling plans for properties we do not operate and other factors both within and outside our control.

Exploration and development activities are subject to a number of risks and uncertainties, which could cause these activities to be less successful than we anticipate. A significant portion of our anticipated cash flows from operations for the remainder of 2016 is expected to come from producing wells and development activities on currently proved properties in the Wolfcamp and Bone Spring plays in the Delaware Basin, the Eagle Ford shale in South Texas and the Haynesville shale in Louisiana. Our existing wells may not produce at the levels we are forecasting and our exploration and development activities in these areas may not be as successful as we anticipate. Additionally, our anticipated cash flows from operations are based upon current expectations of oil and natural gas prices for the remainder of 2016 and the hedges we currently have in place. We use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil, natural gas and natural gas liquids prices and to partially offset reductions in our cash flows from operations resulting from declines in commodity prices. At August 3, 2016, we had approximately 50% of our anticipated oil production and approximately 55% of our anticipated natural gas production hedged for the remainder of 2016. See Note 8 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for a summary of our open derivative financial instruments at June 30, 2016.

Our unaudited cash flows for the six months ended June 30, 2016 and 2015 are presented below:

	Six Months Ended June 30,	
(In thousands)	2016	2015
Net cash provided by operating activities	$49,600	$113,390
Net cash used in investing activities	(166,032)	(293,996)
Net cash provided by financing activities	140,573	225,822
Net change in cash	$24,141	$45,216
Adjusted EBITDA[(1)]	$56,163	$116,829

(1) 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 “— Non-GAAP Financial Measures” below.

Cash Flows Provided by Operating Activities

Net cash provided by operating activities decreased by $63.8 million to $49.6 million for the six months ended June 30, 2016, as compared to net cash provided by operating activities of $113.4 million for the six months ended June 30, 2015. Excluding changes in operating assets and liabilities, net cash provided by operating activities decreased by $65.5 million to $43.5 million for the six months ended June 30, 2016 from $109.0 million for the six months ended June 30, 2015. This decrease is primarily attributable to the 25% decrease in our oil and natural gas revenues between the respective periods. Changes in our operating assets and liabilities between the six months ended June 30, 2015 and the six months ended June 30, 2016 resulted in a net increase of $1.7 million in net cash provided by operating activities for the six months ended June 30, 2016.

Our operating cash flows are sensitive to a number of variables, including changes in our production and volatility of oil and natural gas prices between reporting periods. Regional and worldwide economic activity, the actions of OPEC, weather, infrastructure capacity to reach markets and other variable factors significantly impact the prices of oil and natural gas. These factors are beyond our control and are difficult to predict. We use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil, natural gas and natural gas liquids prices. In addition, we attempt to avoid long-term service agreements where possible in order to minimize ongoing future commitments.

Cash Flows Used in Investing Activities

Net cash used in investing activities decreased by $128.0 million to $166.0 million for the six months ended June 30, 2016 from $294.0 million for the six months ended June 30, 2015. This decrease in net cash used in investing activities for the six months ended June 30, 2016, as compared to the six months ended June 30, 2015, is primarily attributable to the following factors: (i) a decrease of $74.6 million in oil and natural gas properties capital expenditures due to our reduced 2016 capital expenditure budget, (ii) a $23.7 million decrease in cash used as a result of expenditures incurred in 2015 in connection with

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our merger with Harvey E. Yates Company (the "HEYCO Merger") and (iii) a decrease in restricted cash of $44.3 million primarily attributable to the return of cash from the escrow account established to facilitate potential like-kind exchange transactions associated with the sale of certain midstream assets in Loving County, Texas in the fourth quarter of 2015. This decrease was partially offset by the $14.7 million increase in cash used primarily for our midstream investments, including for the construction and installation of the natural gas processing plant and natural gas gathering system in the Rustler Breaks prospect area in Eddy County, New Mexico. Cash used for oil and natural gas properties capital expenditures for the six months ended June 30, 2016 was primarily attributable to our operated drilling and completion activities and the acquisition of additional leasehold and mineral interests in the Delaware Basin. A small portion of our capital expenditures for the six months ended June 30, 2016 was directed to our participation in non-operated wells, primarily in the Delaware Basin and the Haynesville shale.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities decreased by $85.2 million to $140.6 million for the six months ended June 30, 2016 from $225.8 million for the six months ended June 30, 2015. The net cash provided by financing activities for the six months ended June 30, 2016 was attributable to the net proceeds from our March 2016 equity offering of $142.4 million ($141.5 million including cost to issue equity). The net cash provided by financing activities for the six months ended June 30, 2015 was primarily attributable to the net proceeds from our April 2015 Notes offering of approximately $391.0 million, the net proceeds from our April 2015 equity offering of $187.5 million and proceeds from borrowings under the Credit Agreement of $125.0 million. These net proceeds were partially offset by (i) the $477.0 million repayment of the borrowings outstanding under our Credit Agreement and debt obligations assumed in the HEYCO Merger and (ii) the taxes paid on net share settlement of stock-based compensation of $1.6 million.

See Note 5 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for a summary of our debt, including our Credit Agreement and the Notes.

Non-GAAP Financial Measures

We define Adjusted EBITDA as earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, certain other non-cash items and non-cash stock-based compensation expense, and net gain or loss on asset sales and inventory impairment. Adjusted EBITDA is not a measure of net income (loss) or cash flows as determined by GAAP. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. Management believes Adjusted EBITDA is necessary because it allows us to evaluate our operating performance and compare the results of operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in calculating Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which certain assets were acquired.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components of understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner.

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The following table presents our calculation of Adjusted EBITDA and the reconciliation of Adjusted EBITDA to the GAAP financial measures of net loss and net cash provided by operating activities, respectively.

	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands)	2016	2015	2016	2015
Unaudited Adjusted EBITDA Reconciliation to Net Loss:				
Net loss attributable to Matador Resources Company shareholders	$(105,853)	$(157,091)	$(213,507)	$(207,324)
Interest expense	6,167	5,869	13,365	7,939
Total income tax benefit	—	(89,350)	—	(115,740)
Depletion, depreciation and amortization	31,248	51,768	60,170	98,239
Accretion of asset retirement obligations	289	132	552	244
Full-cost ceiling impairment	78,171	229,026	158,633	296,153
Unrealized loss on derivatives	26,625	23,532	33,464	32,090
Stock-based compensation expense	3,310	2,794	5,553	5,131
Net (gain) loss on asset sales and inventory impairment	(1,002)	—	(2,067)	97
Adjusted EBITDA	$38,955	$66,680	$56,163	$116,829

	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands)	2016	2015	2016	2015
Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities:				
Net cash provided by operating activities	$31,242	$20,043	$49,600	$113,390
Net change in operating assets and liabilities	1,944	40,843	(6,117)	(4,389)
Interest expense, net of non-cash portion	5,875	5,869	12,773	7,939
Net income attributable to non-controlling interest in subsidiaries	(106)	(75)	(93)	(111)
Adjusted EBITDA	$38,955	$66,680	$56,163	$116,829

The net loss attributable to Matador Resources Company shareholders decreased by $51.2 million to $105.9 million, or a decrease of 33%, for the three months ended June 30, 2016, as compared to $157.1 million for the three months ended June 30, 2015. This decrease in the net loss for the three months ended June 30, 2016 as compared to the three months ended June 30, 2015 is primarily attributable to (i) the decrease in the full-cost ceiling impairment and (ii) the decrease in depletion, depreciation and amortization expense, which was partially offset by (x) the decrease in the oil and natural gas revenues, (y) the decrease in the realized gain on derivatives and (z) the decrease in the deferred income tax benefit.

The net loss attributable to Matador Resources Company shareholders increased by $6.2 million to $213.5 million, or an increase of 3%, for the six months ended June 30, 2016, as compared to $207.3 million for the six months ended June 30, 2015. This increase in the net loss for the six months ended June 30, 2016 as compared to the six months ended June 30, 2015 is primarily attributable to (i) the decrease in our oil and natural gas revenues, (ii) the decrease in realized gain on derivatives, (iii) the increase in interest expense and (iv) the decrease in the deferred income tax benefit, which was mostly offset by (x) the decrease in the full-cost ceiling impairment and (y) the decrease in depletion, depreciation and amortization expense.

Our Adjusted EBITDA decreased by $27.7 million to $39.0 million, or a decrease of 42%, for the three months ended June 30, 2016, as compared to $66.7 million for the three months ended June 30, 2015. This decrease in our Adjusted EBITDA is primarily attributable to the decrease in our oil and natural gas revenues resulting from lower commodity prices for the three months ended June 30, 2016 as compared to the three months ended June 30, 2015.

Our Adjusted EBITDA decreased by $60.7 million to $56.2 million, or a decrease of 52%, for the six months ended June 30, 2016, as compared to $116.8 million for the six months ended June 30, 2015. This decrease in our Adjusted EBITDA is primarily attributable to the decrease in our oil and natural gas revenues resulting from lower commodity prices for the six months ended June 30, 2016 as compared to the six months ended June 30, 2015.

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Off-Balance Sheet Arrangements

From time-to-time, we enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of June 30, 2016, the material off-balance sheet arrangements and transactions that we have entered into include (i) operating lease agreements, (ii) non-operated drilling commitments, (iii) termination obligations under drilling rig contracts, (iv) firm transportation and fractionation commitments, (v) agreements to construct facilities and (vi) contractual obligations for which the ultimate settlement amounts are not fixed and determinable, such as derivative contracts that are sensitive to future changes in commodity prices or interest rates, gathering, treating, fractionation and transportation commitments on uncertain volumes of future throughput, open delivery commitments and indemnification obligations following certain divestitures. Other than the off-balance sheet arrangements described above, we have no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources. See “Obligations and Commitments” below and Note 10 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for more information regarding our off-balance sheet arrangements. Such information is incorporated herein by reference.

Obligations and Commitments

We had the following material contractual obligations and commitments at June 30, 2016:

	Payments Due by Period				
(In thousands)	Total	Less Than 1 Year	1 - 3 Years	3 - 5 Years	More Than 5 Years
Contractual Obligations:					
Revolving credit borrowings, including letters of credit(1)	$571	$571	$—	$—	$—
Senior unsecured notes(2)	400,000	—	—	—	400,000
Office leases	26,262	2,398	4,984	5,215	13,665
Non-operated drilling commitments(3)	4,169	4,169	—	—	—
Drilling rig contracts(4)	43,035	22,757	20,278	—	—
Asset retirement obligations	18,559	61	1,833	4,121	12,544
Gas processing and transportation agreements(5)	10,628	4,352	6,276	—	—
Gas plant engineering, procurement, construction and installation contract(6)	4,646	4,646	—	—	—
Total contractual cash obligations	$507,870	$38,954	$33,371	$9,336	$426,209

(1) At June 30, 2016, we had no borrowings outstanding under our Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. The Credit Agreement matures in October 2020.

(2) These amounts represent principal maturities only.

(3) At June 30, 2016, we had outstanding commitments to participate in the drilling and completion of various non-operated wells. Our working interests in these wells are typically small, and several of these wells were in progress at June 30, 2016. If all of these wells are drilled and completed, we will have minimum outstanding aggregate commitments for our participation in these wells of $4.2 million at June 30, 2016, which we expect to incur within the next few months.

(4) We do not own or operate our own drilling rigs, but instead enter into contracts with third parties for such rigs. See Note 10 to the interim unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q for more information regarding our contractual commitments.

(5) Effective September 1, 2012, we entered into a firm five-year natural gas processing and transportation agreement for a significant portion of our operated natural gas production in South Texas. Effective October 1, 2015, we entered into a 15-year fixed-fee natural gas gathering and processing agreement for a significant portion of our operated natural gas production in Loving County, Texas. See Note 10 to the interim unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q for more information regarding our

contractual commitments.

(6) In 2015, we entered into an agreement with a third party for the engineering, procurement, construction and installation of a natural gas processing plant in the Rustler Breaks prospect area in Eddy County, New Mexico. See Note 10 to the interim unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q for more information regarding our contractual commitments.

General Outlook and Trends

For the three months ended June 30, 2016, oil prices ranged from a low of approximately $35.70 per Bbl in early April to a high of approximately $51.23 per Bbl in early June, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. We realized an average oil price of $42.84 per Bbl ($43.29 per Bbl including realized gains from oil derivatives) for our oil production for the three months ended June 30, 2016, as compared to $54.37 per Bbl ($62.72

per Bbl including realized gains from oil derivatives) for the three months ended June 30, 2015. Subsequent to June 30, 2016, oil prices have decreased and, at August 3, 2016, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date closed at $40.83 per Bbl, as compared to $45.17 per Bbl at August 3, 2015.

For the three months ended June 30, 2016, natural gas prices ranged from a high of $2.92 per MMBtu in late June to a low of $1.90 per MMBtu in mid-April, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. We realized a weighted average natural gas price of $2.10 per Mcf ($2.34 per Mcf including realized gains from natural gas derivatives) for our natural gas production for the three months ended June 30, 2016, as compared to $2.78 per Mcf ($3.24 per Mcf including aggregate realized gains from natural gas and NGL derivatives) for the three months ended June 30, 2015. Because we report our production volumes in two streams, oil and natural gas, including dry and liquids-rich natural gas, revenues associated with extracted natural gas liquids are included with our natural gas revenues, which has the effect of increasing the weighted average natural gas price realized on a per Mcf basis. Since June 30, 2016, natural gas prices have remained relatively stable, and at August 3, 2016, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date closed at $2.84 per MMBtu, as compared to $2.75 per MMBtu at August 3, 2015.

The prices we receive for oil, natural gas and natural gas liquids heavily influence our revenue, profitability, cash flow available for capital expenditures, access to capital and future rate of growth. Oil, natural gas and natural gas liquids are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil, natural gas and natural gas liquids have been volatile and these markets will likely continue to be volatile in the future. Declines in oil, natural gas or natural gas liquids prices not only reduce our revenues, but could also reduce the amount of oil, natural gas and natural gas liquids we can produce economically. We are uncertain when, or if, oil and natural gas prices may rise from their current levels, and in fact, oil and natural gas prices may decrease in future periods.

From time to time, we use derivative financial instruments to mitigate our exposure to commodity price risk associated with oil, natural gas and natural gas liquids prices. Even so, decisions as to whether, at what price and what production volumes to hedge are difficult and depend on market conditions and our forecast of future production and oil, natural gas and natural gas liquids prices, and we may not always employ the optimal hedging strategy. This, in turn, may affect the liquidity that can be accessed through the borrowing base under our Credit Agreement and through the capital markets. We expect our realized gains from derivatives to be less for the remainder of 2016, as compared to comparable periods in 2015, especially from our oil derivative contracts.

Like other oil and natural gas producing companies, our properties are subject to natural production declines. By their nature, our oil and natural gas wells experience rapid initial production declines. We attempt to overcome these production declines by drilling to develop and identify additional reserves, by exploring for new sources of reserves and, at times, by acquisitions. During times of severe oil, natural gas and natural gas liquids price declines, however, drilling additional oil or natural gas wells may not be economical, and we may find it necessary to reduce capital expenditures and curtail drilling operations in order to preserve liquidity. A material reduction in capital expenditures and drilling activities could materially impact our production volumes, revenues, reserves, cash flows and availability under our Credit Agreement.

We strive to focus our efforts on increasing oil and natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our ability to find and develop sufficient quantities of oil and natural gas reserves at economical costs is critical to our long-term success. Future finding and development costs are subject to changes in the costs of acquiring, drilling and completing our prospects.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Except as set forth below, there have been no material changes to the sources and effects of our market risk since December 31, 2015, which are disclosed in the Annual Report.

Commodity price exposure. We are exposed to market risk as the prices of oil, natural gas and natural gas liquids fluctuate as a result of changes in supply and demand and other factors. To partially reduce price risk caused by these market fluctuations, we have entered into derivative financial instruments in the past and expect to enter into derivative financial instruments in the future to cover a significant portion of our anticipated future production.

We use costless (or zero-cost) collars and/or swap contracts to manage risks related to changes in oil, natural gas and natural gas liquids prices. Costless collars provide us with downside price protection through the purchase of a put option that is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, these arrangements are initially “costless” to us. In the case of a costless collar, the put option and the call option have different fixed price components. In a swap contract, a floating price is exchanged for a fixed price over a specified time, providing downside price protection.

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We record all derivative financial instruments at fair value. The fair value of our 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. At June 30, 2016, Comerica Bank, The Bank of Nova Scotia, BMO Harris Financing, Inc. (Bank of Montreal) and SunTrust Bank (or affiliates thereof) were the counterparties for all of our derivative instruments. We have evaluated the credit standing of the counterparties in determining the fair value of our derivative financial instruments. See Note 8 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for a summary of our open derivative financial instruments at June 30, 2016. Such information is incorporated herein by reference.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this Quarterly Report, we evaluated the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of June 30, 2016 to ensure that (i) information required to be disclosed in the reports the Company files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and that (ii) information required to be disclosed under the Exchange Act is accumulated and communicated to the Company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2016, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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Part II—OTHER INFORMATION

Item 1. Legal Proceedings

We are party to several lawsuits encountered in the ordinary course of business. While the ultimate outcome and impact to us cannot be predicted with certainty, in the opinion of management, it is remote that these lawsuits will have a material adverse impact on our financial condition, results of operations or cash flows.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. For a discussion of such risks and uncertainties, please see "Item 1A. Risk Factors" in the Annual Report.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

During the quarter ended June 30, 2016, the Company re-acquired shares of common stock from certain employees in order to satisfy the employees' tax liability in connection with the vesting of restricted stock.

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased under the Plans or Programs
April 1, 2016 to April 30, 2016	9,960	$ 21.13	—	—
May 1, 2016 to May 31, 2016	2,258	21.14	—	—
June 1, 2016 to June 30, 2016	179	22.28	—	—
Total	12,397	$ 21.15	—	—

(1) The shares were not re-acquired pursuant to any repurchase plan or program.

Item 6. Exhibits

A list of exhibits filed herewith is contained in the Exhibit Index that immediately precedes such exhibits and is incorporated by reference herein.

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SIGNATURES

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

	MATADOR RESOURCES COMPANY
Date: August 5, 2016 By:	/s/ Joseph Wm. Foran
	Joseph Wm. Foran
	Chairman and Chief Executive Officer
Date: August 5, 2016 By:	/s/ David E. Lancaster
	David E. Lancaster
	Executive Vice President and Chief Financial Officer

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EXHIBIT INDEX

Exhibit Number	Description
3.1	Certificate of Merger between Matador Resources Company (now known as MRC Energy Company) and Matador Merger Co. (incorporated by reference to Exhibit 3.4 to our Registration Statement on Form S-1 filed on August 12, 2011).
3.2	Amended and Restated Certificate of Formation of Matador Resources Company (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on February 13, 2012).
3.3	Certificate of Amendment to the Amended and Restated Certificate of Formation of Matador Resources Company (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2015).
3.4	Amended and Restated Bylaws of Matador Resources Company, as amended (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on February 25, 2016).
3.5	Statement of Resolutions for Series A Convertible Preferred Stock (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on March 2, 2015).
4.1	Third Supplemental Indenture, dated as of June 8, 2016, by and among Matador Resources Company, Black River Water Management Company, LLC, the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on June 14, 2016).
10.1	Amended and Restated Annual Incentive Plan for Management and Key Employees (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on June 14, 2016).
23.1	Consent of Netherland, Sewell & Associates, Inc. (filed herewith).
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).
99.1	Audit report of Netherland, Sewell & Associates, Inc. (filed herewith).
101	The following financial information from Matador Resources Company’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2016 formatted in XBRL (eXtensible Business Reporting Language): (i) the Condensed Consolidated Balance Sheets - Unaudited, (ii) the Condensed Consolidated Statements of

Operations - Unaudited, (iii) the Condensed Consolidated Statement of Changes in Shareholders’ Equity - Unaudited, (iv) the Condensed Consolidated Statements of Cash Flows - Unaudited and (v) the Notes to Condensed Consolidated Financial Statements - Unaudited (submitted electronically herewith).