Matador Resources Co
Form 10-Q
August 07, 2017
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, 2017
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	27-4662601
(State or other jurisdiction of incorporation or organization)	(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, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth 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 ¨
	Emerging growth company ¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

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 2, 2017, there were 100,437,295 shares of the registrant's common stock, par value $0.01 per share, outstanding.

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FORM 10-Q
FOR THE QUARTER ENDED JUNE 30, 2017
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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, 2017	December 31, 2016
ASSETS		
Current assets		
Cash	$131,466	$212,884
Restricted cash	15,040	1,258
Accounts receivable		
Oil and natural gas revenues	39,621	34,154
Joint interest billings	37,387	19,347
Other	7,303	5,167
Derivative instruments	7,067	—
Lease and well equipment inventory	2,957	3,045
Prepaid expenses and other assets	5,946	3,327
Total current assets	246,787	279,182
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	2,694,766	2,408,305
Unproved and unevaluated	567,009	479,736
Other property and equipment	204,299	160,795
Less accumulated depletion, depreciation and amortization	(1,939,570)	(1,864,311)
Net property and equipment	1,526,504	1,184,525
Other assets		
Derivative instruments	2,992	—
Other assets	793	958
Total other assets	3,785	958
Total assets	$1,777,076	$1,464,665
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$7,371	$4,674
Accrued liabilities	151,336	101,460
Royalties payable	35,423	23,988
Amounts due to affiliates	5,865	8,651
Derivative instruments	1,192	24,203
Advances from joint interest owners	5,468	1,700
Amounts due to joint ventures	4,873	4,251
Other current liabilities	656	578
Total current liabilities	212,184	169,505
Long-term liabilities		
Senior unsecured notes payable	573,988	573,924
Asset retirement obligations	22,391	19,725
Derivative instruments	—	751
Amounts due to joint ventures	—	1,771
Other long-term liabilities	6,142	7,544
Total long-term liabilities	602,521	603,715

Commitments and contingencies (Note 10)		
Shareholders’ equity		
Common stock - $0.01 par value, 160,000,000 and 120,000,000 shares authorized; 100,399,756 and 99,518,764 shares issued; and 100,324,852 and 99,511,931 shares outstanding, respectively	1,004	995
Additional paid-in capital	1,453,341	1,325,481
Accumulated deficit	(563,858)	(636,351)
Treasury stock, at cost, 74,904 and 6,833 shares, respectively	(745)	—
Total Matador Resources Company shareholders’ equity	889,742	690,125
Non-controlling interest in subsidiaries	72,629	1,320
Total shareholders’ equity	962,371	691,445
Total liabilities and shareholders’ equity	$ 1,777,076	$ 1,464,665

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,	
	2017	2016	2017	2016
Revenues				
Oil and natural gas revenues	$113,764	$69,336	$228,611	$113,262
Third-party midstream services revenues	2,099	918	3,654	1,391
Realized gain (loss) on derivatives	558	2,465	(1,661)	9,528
Unrealized gain (loss) on derivatives	13,190	(26,625)	33,821	(33,464)
Total revenues	129,611	46,094	264,425	90,717
Expenses				
Production taxes, transportation and processing	12,875	10,556	24,682	18,459
Lease operating	16,040	12,183	31,797	26,695
Plant and other midstream services operating	2,942	1,061	5,283	2,088
Depletion, depreciation and amortization	41,274	31,248	75,266	60,170
Accretion of asset retirement obligations	314	289	614	552
Full-cost ceiling impairment	—	78,171	—	158,633
General and administrative	17,177	13,197	33,515	26,360
Total expenses	90,622	146,705	171,157	292,957
Operating income (loss)	38,989	(100,611)	93,268	(202,240)
Other income (expense)				
Net gain on asset sales and inventory impairment	—	1,002	7	2,067
Interest expense	(9,224)	(6,167)	(17,679)	(13,365)
Other income	1,922	29	1,991	124
Total other expense	(7,302)	(5,136)	(15,681)	(11,174)
Net income (loss)	31,687	(105,747)	77,587	(213,414)
Net income attributable to non-controlling interest in subsidiaries	(3,178)	(106)	(5,094)	(93)
Net income (loss) attributable to Matador Resources Company shareholders	$28,509	$(105,853)	$72,493	$(213,507)
Earnings (loss) per common share				
Basic	$0.28	$(1.15)	$0.72	$(2.40)
Diluted	$0.28	$(1.15)	$0.72	$(2.40)
Weighted average common shares outstanding				
Basic	100,211	92,346	100,005	88,826
Diluted	100,227	92,346	100,455	88,826

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, 2017

	Common Stock		Additional paid-in capital	Accumulated deficit	Treasury Stock		Total shareholders' equity attributable to Matador Resources Company	Non-controlling interest in subsidiaries	Total shareholders' equity
	Shares	Amount			Shares	Amount			
Balance at January 1, 2017	99,519	$995	$1,325,481	$(636,351)	6	$—	$690,125	$1,320	$691,445
Issuance of common stock pursuant to employee stock compensation plan	499	5	(5)	—	—	—	—	—	—
Common stock issued to Board members and advisors	55	1	(1)	—	—	—	—	—	—
Stock-based compensation expense related to equity-based awards including amounts capitalized	—	—	12,521	—	—	—	12,521	—	12,521
Stock options exercised, net of options forfeited in net share settlements	327	3	(27)	—	—	—	(24)	—	(24)
Restricted stock forfeited	—	—	—	—	69	(745)	(745)	—	(745)
Purchase of non-controlling interest of less-than-wholly-owned subsidiary	—	—	(1,250)	—	—	—	(1,250)	(1,403)	(2,653)
Contributions related to formation of Joint Venture (see Note 3)	—	—	116,622	—	—	—	116,622	54,878	171,500
Contributions from non-controlling interest owners of less-than-wholly-owned subsidiaries	—	—	—	—	—	—	—	14,700	14,700
Distributions to non-controlling interest owners of less-than-wholly-owned subsidiaries	—	—	—	—	—	—	—	(1,960)	(1,960)
	—	—	—	72,493	—	—	72,493	5,094	77,587

Current period net income									
Balance at June 30, 2017	100,400	$1,004	$1,453,341	$(563,858)	75	$(745)	$889,742	$72,629	$962,371

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, 2017	2016
Operating activities		
Net income (loss)	$77,587	$(213,414)
Adjustments to reconcile net income (loss) to net cash provided by operating activities		
Unrealized (gain) loss on derivatives	(33,821)	33,464
Depletion, depreciation and amortization	75,266	60,170
Accretion of asset retirement obligations	614	552
Full-cost ceiling impairment	—	158,633
Stock-based compensation expense	11,192	5,553
Amortization of debt issuance cost	64	592
Net gain on asset sales and inventory impairment	(7)	(2,067)
Changes in operating assets and liabilities		
Accounts receivable	(25,642)	(2,751)
Lease and well equipment inventory	(140)	(514)
Prepaid expenses	(2,619)	186
Other assets	165	520
Accounts payable, accrued liabilities and other current liabilities	4,442	2,451
Royalties payable	11,435	153
Advances from joint interest owners	3,768	5,083
Income taxes payable	—	(2,848)
Other long-term liabilities	(1,062)	3,837
Net cash provided by operating activities	121,242	49,600
Investing activities		
Oil and natural gas properties capital expenditures	(328,929)	(162,381)
Expenditures for other property and equipment	(41,743)	(47,548)
Proceeds from sale of assets	977	—
Restricted cash	—	43,437
Restricted cash in less-than-wholly-owned subsidiaries	(13,783)	460
Net cash used in investing activities	(383,478)	(166,032)
Financing activities		
Proceeds from issuance of common stock	—	142,350
Cost to issue equity	—	(768)
Proceeds from stock options exercised	2,201	—
Contributions related to formation of Joint Venture	171,500	—
Contributions from non-controlling interest owners of less-than-wholly-owned subsidiaries	14,700	—
Distributions to non-controlling interest owners of less-than-wholly-owned subsidiaries	(1,960)	—
Taxes paid related to net share settlement of stock-based compensation	(2,970)	(1,009)
Purchase of non-controlling interest of less-than-wholly-owned subsidiary	(2,653)	—
Net cash provided by financing activities	180,818	140,573
(Decrease) increase in cash	(81,418)	24,141
Cash at beginning of period	212,884	16,732
Cash at end of period	$131,466	$40,873

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. Additionally, the Company conducts midstream operations, primarily through its midstream joint venture, San Mateo Midstream, LLC ("San Mateo" or the "Joint Venture"), in support of the Company's exploration, development and production operations and provides natural gas processing, natural gas, oil and salt water gathering services and salt water disposal services to third parties on a limited basis.

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, 2016 (the "Annual Report") filed with the SEC. The Company consolidates certain subsidiaries and joint ventures that are less than wholly owned and are not involved in oil and natural gas exploration, including San Mateo, 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, 2017. Amounts as of December 31, 2016 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.

Reclassifications

Certain reclassifications have been made to the prior periods' financial statements to conform to the current period presentation. As a result of the growth of the Company's midstream operations, these operations met the required threshold for segment reporting. As a result, $0.9 million for the three months ended June 30, 2016 and $1.4 million for the six months ended June 30, 2016 were reclassified from other income to third-party midstream services revenues. In addition, $1.1 million related to midstream operating costs for the three months ended June 30, 2016 and $2.1 million for the six months ended June 30, 2016 were reclassified from lease operating expenses to plant and other

midstream services operating expenses. These reclassifications had no effect on previously reported results of operations, cash flows or retained earnings.
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 that 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 12-month period. For the three and six months ended June 30, 2017, the cost center ceiling was higher than the capitalized costs

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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

of oil and natural gas properties; no impairment charge was necessary. However, due primarily to declines in oil and natural gas prices in early 2016, the capitalized costs of oil and natural gas properties exceeded the cost center ceiling for the three and six months ended June 30, 2016, and as a result, the Company recorded impairment charges to its net capitalized costs of $78.2 million and $158.6 million, respectively, in its interim unaudited condensed consolidated statements of operations.

The Company capitalized approximately $5.2 million and $4.0 million of its general and administrative costs for the three months ended June 30, 2017 and 2016, respectively, and approximately $1.9 million and $1.7 million of its interest expense for the three months ended June 30, 2017 and 2016, respectively. The Company capitalized approximately $10.8 million and $6.0 million of its general and administrative costs for the six months ended June 30, 2017 and 2016, respectively, and approximately $3.2 million and $2.2 million of its interest expense for the six months ended June 30, 2017 and 2016, respectively.

Earnings (Loss) Per Common Share

The Company reports basic earnings (loss) attributable to Matador Resources Company shareholders per common share, which excludes the effect of potentially dilutive securities, and diluted earnings (loss) attributable to Matador Resources Company shareholders 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, 2017 and 2016 (in thousands).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Weighted average common shares outstanding				
Basic	100,211	92,346	100,005	88,826
Dilutive effect of options and restricted stock units	16	—	450	—
Diluted weighted average common shares outstanding	100,227	92,346	100,455	88,826

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.

Recent Accounting Pronouncements

Revenue from Contracts with Customers. In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2014-09, Revenue from Contracts with Customers (Topic 606), which specifies how and when to recognize revenue. 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. In August 2015, the FASB issued ASU 2015-14, which defers the effective date of ASU 2014-09 for one year to fiscal years beginning after December 15, 2017. Early adoption is permitted for fiscal years beginning after December 15, 2016. In May 2016, the FASB issued ASU 2016-11, which rescinds guidance from the SEC on accounting for gas balancing arrangements and will eliminate the use of the entitlements method. Entities have the option of using either a full retrospective or modified approach to adopt the new standards. In December 2016, the FASB issued ASU 2016-20, which clarifies disclosure requirements in ASU 2014-09. The Company expects to adopt the new guidance effective January 1, 2018 using the modified approach. The Company is evaluating the new guidance, including (i) identification of revenue streams and (ii) review of contracts and procedures currently in place.

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

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

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.

Statement of Cash Flows. In November 2016, the FASB issued ASU 2016-18, Statement of Cash Flows (Topic 230), which specifies that a statement of cash flows explain the change during the period in the total of cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. This ASU will become effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. Early adoption is permitted, including adoption in an interim period. The update should be applied using a retrospective transition method to each period presented. The Company believes that the impact of the adoption of this ASU will change the presentation of its beginning and ending cash balances on its Consolidated Statements of Cash Flows and eliminate the presentation of changes in restricted cash balances from investing activities on its Consolidated Statements of Cash Flows.

Clarifying the Definition of a Business. In January 2017, the FASB issued ASU 2017-01, Business Combinations (Topic 805), which specifies the minimum inputs and processes required for an integrated set of assets and activities to meet the definition of a business. This ASU will become effective for fiscal years beginning after December 15, 2017 with early adoption permitted. Entities are required to apply guidance prospectively upon adoption. The Company is currently evaluating the impact of the adoption of this ASU on its consolidated financial statements.

NOTE 3 – BUSINESS COMBINATION

Joint Venture

On February 17, 2017, the Company contributed substantially all of its midstream assets located in the Rustler Breaks (Eddy County, New Mexico) and Wolf (Loving County, Texas) asset areas in the Delaware Basin to San Mateo, a joint venture with a subsidiary of Five Point Capital Partners LLC (“Five Point”). The midstream assets contributed to San Mateo include (i) the Black River cryogenic natural gas processing plant in the Rustler Breaks asset area (the “Black River Processing Plant”); (ii) one salt water disposal well and a related commercial salt water disposal facility in the Rustler Breaks asset area; (iii) three salt water disposal wells and related commercial salt water disposal facilities in the Wolf asset area; and (iv) substantially all related oil, natural gas and water gathering systems and pipelines in both the Rustler Breaks and Wolf asset areas (collectively, the “Delaware Midstream Assets”). The Company continues to operate the Delaware Midstream Assets. The Company retained its ownership in certain midstream assets in South Texas and Northwest Louisiana, which are not part of the Joint Venture.

The Company and Five Point own 51% and 49% of the Joint Venture, respectively. Five Point provided initial cash consideration of $176.4 million to the Joint Venture in exchange for its 49% interest. Approximately $171.5 million of this cash contribution by Five Point was distributed by the Joint Venture to the Company as a special distribution. The Company may earn an additional $73.5 million in performance incentives over the next five years. The Company contributed the Delaware Midstream Assets and $5.1 million in cash to the Joint Venture in exchange for its 51% interest. The parties to the Joint Venture have also committed to spend up to an additional $140.0 million in the aggregate to expand the Joint Venture’s midstream operations and asset base. The Joint Venture is consolidated in the Company’s interim unaudited condensed consolidated financial statements with Five Point’s interest in the Joint Venture being accounted for as a non-controlling interest.

In connection with the Joint Venture, the Company dedicated its current and future leasehold interests in the Rustler Breaks and Wolf asset areas pursuant to 15-year, fixed-fee natural gas, oil and salt water gathering agreements and salt water disposal agreements, effective as of February 1, 2017. In addition, the Company dedicated its current and future leasehold interests in the Rustler Breaks asset area pursuant to a 15-year, fixed fee natural gas processing agreement (see Note 10).

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

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, 2017 (in thousands).

Beginning asset retirement obligations	$20,640
Liabilities incurred during period	1,222
Liabilities settled during period	(176)
Revisions in estimated cash flows	794
Accretion expense	614
Ending asset retirement obligations	23,094
Less: current asset retirement obligations[1]	(703)
Long-term asset retirement obligations	$22,391

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(1) Included in accrued liabilities in the Company's interim unaudited condensed consolidated balance sheet at June 30, 2017.

NOTE 5 - DEBT

At June 30, 2017 and August 2, 2017, the Company had $575.0 million of outstanding 6.875% senior notes due 2023, no borrowings outstanding under the Company's revolving credit agreement (the "Credit Agreement") and approximately $0.8 million in outstanding letters of credit issued pursuant to the Credit Agreement.

Credit Agreement

The borrowing base under the Credit Agreement is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of the Company's proved oil and natural gas reserves at December 31 and June 30 of each year, respectively. Both the Company and the lenders may request an unscheduled redetermination of the borrowing base once each between scheduled redetermination dates. During the first quarter of 2017, the lenders completed their review of the Company's proved oil and natural gas reserves at December 31, 2016, and on April 28, 2017, the borrowing base was increased to $450.0 million and the maximum facility amount remained at $500.0 million. The Company elected to keep the borrowing commitment at $400.0 million. Borrowings under the Credit Agreement are limited to the least of the borrowing base, the maximum facility amount and the elected commitment. The Credit Agreement matures on October 16, 2020.

In the event of an increase in the elected commitment, 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 increase. Total deferred loan costs were $1.1 million at June 30, 2017, and these costs are being amortized over the term of the Credit Agreement, which approximates amortization of these costs using the effective interest method. If, upon a 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 the Credit Agreement at June 30, 2017.

Senior Unsecured Notes

On April 14, 2015 and December 9, 2016, the Company issued $400.0 million and $175.0 million, respectively, of 6.875% senior notes due 2023 (collectively, the "Notes"). The Notes mature on April 15, 2023, and interest is payable semi-annually in arrears on April and October 15 of each year.

On May 24, 2017, and pursuant to a registered exchange offer, the Company exchanged all of the $175.0 million of Notes issued on December 9, 2016, which were privately placed, for a like principal amount of 6.875% senior notes due 2023 that have been registered under the Securities Act of 1933, as amended. The terms of such registered Notes are substantially the same as the terms of the original Notes except that the transfer restrictions, registration rights and provisions for additional interest relating to the original Notes do not apply to the registered Notes.

NOTE 5 - DEBT - Continued

On February 17, 2017, in connection with the formation of San Mateo (see Note 3), Matador entered into a Fourth Supplemental Indenture (the "Fourth Supplemental Indenture"), which supplements the indenture governing the Notes. Pursuant to the Fourth Supplemental Indenture, (i) Longwood Midstream Holdings, LLC, the holder of Matador's 51% equity interest in San Mateo, was designated as a guarantor of the Notes and (ii) DLK Black River Midstream, LLC and Black River Water Management Company, LLC, each subsidiaries of San Mateo, were released as parties to, and as guarantors of, the Notes. The guarantors of the Notes, following the effectiveness of the Fourth Supplemental Indenture, are referred to herein as the "Guarantor Subsidiaries." San Mateo and its subsidiaries (the "Non-Guarantor Subsidiaries") are not guarantors of the Notes, although they remain restricted subsidiaries under the indenture governing the Notes.

The following presents condensed consolidating financial information on an issuer (Matador), Non-Guarantor Subsidiaries, Guarantor Subsidiaries and consolidated basis (in thousands). Elimination entries are necessary to combine the entities. This financial information is presented in accordance with the requirements of Rule 3-10 of Regulation S-X. The following financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantor Subsidiaries operated as independent entities.

Condensed Consolidating Balance Sheet
June 30, 2017

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
ASSETS					
Intercompany receivable	$385,885	$ —	$ 1,679	$(387,564)	$ —
Third-party current assets	2,944	16,953	226,890	—	246,787
Net property and equipment	—	151,331	1,375,173	—	1,526,504
Investment in subsidiaries	1,083,542	—	75,585	(1,159,127)	—
Third-party long-term assets	—	—	3,785	—	3,785
Total assets	$ 1,472,371	$ 168,284	$ 1,683,112	$(1,546,691)	$ 1,777,076
LIABILITIES AND EQUITY					
Intercompany payable	$—	$ 1,679	$385,885	$(387,564)	$ —
Third-party current liabilities	8,640	17,753	185,791	—	212,184
Senior unsecured notes payable	573,988	—	—	—	573,988
Other third-party long-term liabilities	—	639	27,894	—	28,533
Total equity attributable to Matador Resources Company	889,743	75,584	1,083,542	(1,159,127)	889,742
Non-controlling interest in subsidiaries	—	72,629	—	—	72,629
Total liabilities and equity	$ 1,472,371	$ 168,284	$ 1,683,112	$(1,546,691)	$ 1,777,076

Condensed Consolidating Balance Sheet
December 31, 2016

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
ASSETS					
Intercompany receivable	$316,791	$ 3,571	$ 12,091	$(332,453)	$ —
Third-party current assets	101,102	4,242	173,838	—	279,182
Net property and equipment	33	113,107	1,071,385	—	1,184,525
Investment in subsidiaries	856,762	—	90,275	(947,037)	—
Third-party long-term assets	—	—	958	—	958

Total assets	$1,274,688	$ 120,920	$1,348,547	$(1,279,490)	$1,464,665
LIABILITIES AND EQUITY					
Intercompany payable	$—	$ 12,091	$320,362	$(332,453)	$—
Third-party current liabilities	9,265	16,632	143,608	—	169,505
Senior unsecured notes payable	573,924	—	—	—	573,924
Other third-party long-term liabilities	1,374	602	27,815	—	29,791
Total equity attributable to Matador Resources Company	690,125	90,275	856,762	(947,037)	690,125
Non-controlling interest in subsidiaries	—	1,320	—	—	1,320
Total liabilities and equity	$1,274,688	$ 120,920	$1,348,547	$(1,279,490)	$1,464,665

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

NOTE 5 - DEBT - Continued

Condensed Consolidating Statement of Operations
For the Three Months Ended June 30, 2017

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Total revenues	$—	$ 11,274	$ 127,198	$ (8,861)	$ 129,611
Total expenses	1,586	4,814	93,083	(8,861)	90,622
Operating (loss) income	(1,586)	6,460	34,115	—	38,989
Net gain on asset sales and inventory impairment	—	—	—	—	—
Interest expense	(9,224)	—	—	—	(9,224)
Other income	(27)	26	1,923	—	1,922
Earnings in subsidiaries	39,228	—	3,244	(42,472)	—
Income before income taxes	28,391	6,486	39,282	(42,472)	31,687
Total income tax (benefit) provision	(118)	64	54	—	—
Net income attributable to non-controlling interest in subsidiaries	—	(3,178)	—	—	(3,178)
Net income attributable to Matador Resources Company shareholders	$ 28,509	$ 3,244	$ 39,228	$ (42,472)	$ 28,509

Condensed Consolidating Statement of Operations
For the Three Months Ended June 30, 2016

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Total revenues	$—	$ 3,210	$ 44,778	$ (1,894)	$ 46,094
Total expenses	1,032	1,244	146,323	(1,894)	146,705
Operating (loss) income	(1,032)	1,966	(101,545)	—	(100,611)
Net gain on asset sales and inventory impairment	—	—	1,002	—	1,002
Interest expense	(6,167)	—	—	—	(6,167)
Other income	—	—	29	—	29
(Loss) earnings in subsidiaries	(98,672)	—	1,842	96,830	—
(Loss) income before income taxes	(105,871)	1,966	(98,672)	96,830	(105,747)
Total income tax (benefit) provision	(18)	18	—	—	—
Net income attributable to non-controlling interest in subsidiaries	—	(106)	—	—	(106)
Net (loss) income attributable to Matador Resources Company shareholders	$ (105,853)	$ 1,842	$ (98,672)	$ 96,830	$ (105,853)

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

NOTE 5 - DEBT - Continued

Condensed Consolidating Statement of Operations
For the Six Months Ended June 30, 2017

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Total revenues	$—	$ 20,937	$ 259,846	$ (16,358)	$ 264,425
Total expenses	2,846	8,682	175,987	(16,358)	171,157
Operating (loss) income	(2,846)	12,255	83,859	—	93,268
Net gain on asset sales and inventory impairment	—	—	7	—	7
Interest expense	(17,679)	—	—	—	(17,679)
Other income	—	26	1,965	—	1,991
Earnings in subsidiaries	92,900	—	7,069	(99,969)	—
Income before income taxes	72,375	12,281	92,900	(99,969)	77,587
Total income tax (benefit) provision	(118)	118	—	—	—
Net income attributable to non-controlling interest in subsidiaries	—	(5,094)	—	—	(5,094)
Net income attributable to Matador Resources Company shareholders	$72,493	$ 7,069	$ 92,900	$ (99,969)	$ 72,493

Condensed Consolidating Statement of Operations
For the Six Months Ended June 30, 2016

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Total revenues	$—	$ 4,527	$ 88,825	$ (2,635)	$ 90,717
Total expenses	2,967	2,377	290,248	(2,635)	292,957
Operating (loss) income	(2,967)	2,150	(201,423)	—	(202,240)
Net gain on asset sales and inventory impairment	—	—	2,067	—	2,067
Interest expense	(13,365)	—	—	—	(13,365)
Other income	—	—	124	—	124
(Loss) earnings in subsidiaries	(197,200)	—	2,032	195,168	—
Income before income taxes	(213,532)	2,150	(197,200)	195,168	(213,414)
Total income tax (benefit) provision	(25)	25	—	—	—
Net income attributable to non-controlling interest in subsidiaries	—	(93)	—	—	(93)
Net (loss) income attributable to Matador Resources Company shareholders	$ (213,507)	$ 2,032	$ (197,200)	$ 195,168	$ (213,507)

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

NOTE 5 - DEBT - Continued

Condensed Consolidating Statement of Cash Flows
For the Six Months Ended June 30, 2017

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Net cash (used in) provided by operating activities	$(98,583)	$ 1,566	$ 218,259	$ —	$ 121,242
Net cash provided by (used in) investing activities	33	(51,580)	(198,051)	(133,880)	(383,478)
Net cash provided by (used in) financing activities	—	47,707	(769)	133,880	180,818
(Decrease) increase in cash	(98,550)	(2,307)	19,439	—	(81,418)
Cash at beginning of period	99,795	2,307	110,782	—	212,884
Cash at end of period	$1,245	$ —	$ 130,221	$ —	$ 131,466

Condensed Consolidating Statement of Cash Flows
For the Six Months Ended June 30, 2016

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Net cash (used in) provided by operating activities	$(24,519)	$ (6,198)	$ 80,317	$ —	$ 49,600
Net cash used in investing activities	(117,086)	(44,074)	(172,108)	167,236	(166,032)
Net cash provided by financing activities	141,582	50,150	116,077	(167,236)	140,573
(Decrease) increase in cash	(23)	(122)	24,286	—	24,141
Cash at beginning of period	80	186	16,466	—	16,732
Cash at end of period	$57	$ 64	$ 40,752	$ —	$ 40,873

NOTE 6 - INCOME TAXES

The Company’s deferred tax assets exceeded its deferred tax liabilities at June 30, 2017 due to the deferred tax assets generated by the full-cost ceiling impairment charges recorded in prior periods; 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 retained a full valuation allowance at June 30, 2017 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.

NOTE 7 - STOCK-BASED COMPENSATION

In February 2017, the Company granted awards of 228,174 shares of restricted stock and options to purchase 590,128 shares of the Company’s common stock at an exercise price of $27.26 per share to certain of its employees. The fair value of these awards was approximately $12.4 million. All of these awards vest ratably over three years. In February 2017, the Company also granted awards of 174,561 shares of restricted stock and options to purchase 444,491 shares of the Company’s common stock at an exercise price of $26.86 per share to certain of its employees. The fair value of these awards was approximately $9.3 million. All of these awards vest ratably over three years.

In June 2017, the Company granted an employee an award of 87,757 shares of common stock that vested immediately on the grant date. The fair value of this award was approximately $2.1 million. In June 2017, the Company also accelerated the expense for 97,797 restricted stock units issued to directors and outstanding prior to June 2017, resulting from a change in the vesting schedule applicable to equity awards granted to the Company’s directors. The total expense associated with these restricted stock units recognized in the three months ended June 30, 2017 was approximately $1.5 million.

NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS

At June 30, 2017, 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 2017 and 2018.
The following is a summary of the Company's open costless collar contracts for oil and natural gas at June 30, 2017.

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	07/01/2017 - 12/31/2017	2,460,000	$ 45.17	$ 55.75	$ 4,365
Oil	01/01/2018 - 12/31/2018	1,920,000	$ 43.91	$ 63.44	4,990
Natural Gas	07/01/2017 - 12/31/2017	12,540,000	$ 2.51	$ 3.60	(500)
Natural Gas	01/01/2018 - 12/31/2018	16,800,000	$ 2.58	$ 3.67	12
Total open derivative financial instruments					$ 8,867

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.
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, 2017 and December 31, 2016 (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, 2017			
Current assets	$ 10,835	$ (3,768)	$ 7,067
Other assets	5,066	(2,074)	2,992
Current liabilities	(4,915)	3,723	(1,192)
Other liabilities	(2,074)	2,074	—
Total	$ 8,912	$ (45)	$ 8,867
December 31, 2016			
Current liabilities	$ (24,203)	$ —	$ (24,203)
Other liabilities	(751)	—	(751)
Total	$ (24,954)	$ —	$ (24,954)

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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 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	2017	2016	2017	2016
Derivative Instrument					
Oil	Revenues: Realized gain (loss) on derivatives	$581	$561	$(1,053)	$6,024
Natural Gas	Revenues: Realized (loss) gain on derivatives	(23)	1,904	(608)	3,504
Realized gain (loss) on derivatives		558	2,465	(1,661)	9,528
Oil	Revenues: Unrealized gain (loss) on derivatives	10,643	(19,319)	28,422	(26,974)
Natural Gas	Revenues: Unrealized gain (loss) on derivatives	2,547	(7,306)	5,399	(6,490)
Unrealized gain (loss) on derivatives		13,190	(26,625)	33,821	(33,464)
Total		$13,748	$(24,160)	$32,160	$(23,936)

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.

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 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 that 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, 2017 and December 31, 2016 (in thousands).

	Fair Value Measurements at June 30, 2017 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Oil and natural gas derivatives	$—	$10,059	$—	$10,059

Oil and natural gas derivatives	—	(1,192)	—	(1,192)
Total	$—	$8,867	$—	$8,867

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

NOTE 9 - FAIR VALUE MEASUREMENTS - Continued

Description	Fair Value Measurements at December 31, 2016 using Level 1	Level 2	Level 3	Total
Liabilities				
Oil and natural gas derivatives	$ —	$ (24,954)	$ —	$ (24,954)
Total	$ —	$ (24,954)	$ —	$ (24,954)

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

Other Fair Value Measurements

At June 30, 2017 and December 31, 2016, the carrying values reported on the interim unaudited condensed consolidated balance sheets for accounts receivable, prepaid expenses and other assets, accounts payable, accrued liabilities, royalties payable, amounts due to affiliates, advances from joint interest owners, amounts due to joint ventures and other current liabilities approximated their fair values due to their short-term maturities.

At June 30, 2017 and December 31, 2016, the fair value of the Notes was $592.3 million and $605.2 million, respectively, based on quoted market prices, which represent Level 1 inputs in the fair value hierarchy.

NOTE 10 - COMMITMENTS AND CONTINGENCIES

Processing, Transportation and Salt Water Disposal Commitments

Eagle Ford

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, and the revenue the Company receives varies with the quality of natural gas transported to the processing facilities and the contract period.

Under this agreement, if the Company does not meet 80% of the maximum thermal quantity transportation and processing commitments in a contract year, it will be required to pay a deficiency fee per MMBtu of natural gas deficiency. Any quantity in excess of the maximum MMBtu delivered in a contract year can be carried over to the next contract year for purposes of calculating the natural gas deficiency. During certain prior periods, the Company had an immaterial natural gas deficiency, and the counterparty to this agreement waived the deficiency fee. The Company paid $0.5 million and $0.8 million in processing and transportation fees under this agreement during the three months ended June 30, 2017 and 2016, respectively, and $1.0 million and $1.7 million in processing and transportation fees under this agreement during the six months ended June 30, 2017 and 2016, respectively. The future undiscounted minimum payment under this agreement as of June 30, 2017 was $0.2 million.

Delaware Basin — Loving County, Texas Natural Gas Processing

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 in West Texas through the counterparty's gathering system for processing at the counterparty's facilities. Under this agreement, if the Company does not meet the volume commitment for transportation and processing at the facilities 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 transportation 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, 2017, the total deficiency fee required to be paid would be approximately $11.6 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

NOTE 10 - COMMITMENTS AND CONTINGENCIES - Continued

contract year can be carried over to the next contract year for purposes of calculating the natural gas deficiency. The Company paid approximately $3.7 million and $2.8 million in natural gas processing and gathering fees under this agreement during the three months ended June 30, 2017 and 2016, respectively, and $6.8 million and $4.7 million in natural gas processing and gathering fees under this agreement during the six months ended June 30, 2017 and 2016, respectively. The Company can elect to either sell the residue gas to the counterparty at the tailgate of its processing plants or have the counterparty deliver to the Company the residue gas in-kind to be sold to third parties downstream of the plants.

Delaware Basin — San Mateo

In connection with the Joint Venture, effective as of February 1, 2017, the Company dedicated its current and future leasehold interests in the Rustler Breaks and Wolf asset areas pursuant to 15-year, fixed-fee natural gas, oil and salt water gathering agreements and salt water disposal agreements. In addition, the Company dedicated its current and future leasehold interests in the Rustler Breaks asset area pursuant to a 15-year, fixed-fee natural gas processing agreement (collectively with the gathering and salt water disposal agreements, the “Operational Agreements”). The Joint Venture will provide the Company with firm service under each of the Operational Agreements in exchange for certain minimum volume commitments. The minimum contractual obligation under the Operational Agreements at June 30, 2017 was approximately $256.4 million.

Beginning in May 2017, a subsidiary of San Mateo entered into certain agreements with third parties for the engineering, procurement, construction and installation of an expansion of the Black River Processing Plant, including required compression. The expansion is expected to be placed into service in 2018. San Mateo’s total commitments under these agreements are $56.9 million. The subsidiary of San Mateo paid approximately $7.9 million and $9.9 million under these agreements during the three and six months ended June 30, 2017. As of June 30, 2017, the remaining obligations under these agreements were $47.0 million, which are expected to be incurred within the next year.

Other Commitments

The Company does not own or operate its own drilling rigs, but instead enters into contracts with third parties for such drilling 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 two years or less. The Company would incur a termination obligation if the Company elected to terminate a contract and if the drilling contractor were unable to secure replacement 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 $42.0 million at June 30, 2017.

At June 30, 2017, the Company had outstanding commitments to participate in the drilling and completion of various non-operated wells. If all of these wells are drilled and completed as proposed, the Company’s minimum outstanding aggregate commitments for its participation in these non-operated wells were approximately $19.7 million at June 30, 2017. The Company expects these costs to be incurred within the next year.

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, 2017 and December 31, 2016 (in thousands).

	June 30, 2017	December 31, 2016
Accrued evaluated and unproved and unevaluated property costs	$98,589	$54,273
Accrued support equipment and facilities costs	15,596	15,139
Accrued lease operating expenses	12,613	16,009
Accrued interest on debt	8,345	6,541
Accrued asset retirement obligations	703	915
Accrued partners' share of joint interest charges	12,479	5,572
Other	3,011	3,011
Total accrued liabilities	$151,336	$101,460

Supplemental Cash Flow Information

The following table provides supplemental disclosures of cash flow information for the six months ended June 30, 2017 and 2016 (in thousands).

	Six Months Ended June 30,	
	2017	2016
Cash paid for interest expense, net of amounts capitalized	$15,875	$12,226
Increase in asset retirement obligations related to mineral properties	$1,978	$2,511
(Decrease) increase in asset retirement obligations related to support equipment and facilities	$(138)	$75
Increase (decrease) in liabilities for oil and natural gas properties capital expenditures	$43,797	$(3,476)
Increase (decrease) in liabilities for support equipment and facilities	$1,838	$(11,565)
Stock-based compensation expense recognized as liability	$(339)	$88
(Decrease) increase in liabilities for accrued cost to issue equity	$(343)	$62
Transfer of inventory from oil and natural gas properties	$(228)	$474

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

NOTE 12 - SEGMENT INFORMATION

The Company operates in two business segments: (i) exploration and production and (ii) midstream. The exploration and production segment is engaged in the acquisition, exploration and development of oil and natural gas properties and is currently 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. The midstream segment conducts midstream operations in support of the Company's exploration, development and production operations and provides natural gas processing, natural gas, oil and salt water gathering services and salt water disposal services to third parties on a limited basis. As of February 17, 2017, substantially all of the Company's midstream operations in the Rustler Breaks and Wolf asset areas in the Delaware Basin are conducted through San Mateo (see Note 3).

The following tables present selected financial information for the periods presented regarding the Company's business segments on a stand-alone basis, corporate expenses that are not allocated to a segment and the consolidation and elimination entries necessary to arrive at the financial information for the Company on a consolidated basis (in thousands). On a consolidated basis, midstream services revenues consist primarily of those revenues from midstream operations related to third parties, including working interest owners in the Company's operated wells. All midstream services revenues associated with Company-owned production are eliminated in consolidation. In evaluating the operating results of the exploration and production and midstream segments, the Company does not allocate certain expenses to the individual segments, including general and administrative expenses. Such expenses are reflected in the column labeled "Corporate."

	Exploration and Production	Midstream	Corporate	Consolidations and Eliminations	Consolidated Company
Three Months Ended June 30, 2017					
Oil and natural gas revenues	$113,387	$377	$—	$ —	$113,764
Midstream services revenues	—	11,367	—	(9,268)	2,099
Realized gain on derivatives	558	—	—	—	558
Unrealized gain on derivatives	13,190	—	—	—	13,190
Expenses(1)	78,078	5,960	15,852	(9,268)	90,622
Operating income (loss)(2)	$49,057	$5,784	$(15,852)	$ —	$38,989
Total assets	$1,436,678	$192,889	$147,509	$ —	$1,777,076
Capital expenditures(3)	$165,583	$27,347	$1,752	$ —	$194,682

(1) Includes depletion, depreciation and amortization expenses of $39.6 million and $1.3 million for the exploration and production and midstream segments, respectively. Also includes corporate depletion, depreciation and amortization expenses of $0.4 million.

(2) Includes $3.2 million in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

(3) Includes $13.4 million in capital expenditures attributable to non-controlling interest in subsidiaries related to the midstream segment.

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

NOTE 12 - SEGMENT INFORMATION - Continued

	Exploration and Production	Midstream	Corporate	Consolidations and Eliminations	Consolidated Company
Three Months Ended June 30, 2016					
Oil and natural gas revenues	$ 68,864	$ 472	$ —	$ —	$ 69,336
Midstream services revenues	—	3,469	—	(2,551)	918
Realized gain on derivatives	2,465	—	—	—	2,465
Unrealized loss on derivatives	(26,625)	—	—	—	(26,625)
Expenses[1]	134,338	1,562	13,356	(2,551)	146,705
Operating (loss) income[2]	$ (89,634)	$ 2,379	$ (13,356)	$ —	$ (100,611)
Total assets	$ 927,557	$ 106,425	$ 52,106	$ —	$ 1,086,088
Capital expenditures	$ 97,309	$ 11,192	$ 2,328	$ —	$ 110,829

(1) Includes depletion, depreciation and amortization expenses of $30.6 million and $0.5 million for the exploration and production and midstream segments, respectively, and full-cost ceiling impairment expenses of $78.2 million for the exploration and production segment. Also includes corporate depletion, depreciation and amortization expenses of $0.2 million.

(2) Includes $106,000 in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

	Exploration and Production	Midstream	Corporate	Consolidations and Eliminations	Consolidated Company
Six Months Ended June 30, 2017					
Oil and natural gas revenues	$ 227,552	$ 1,059	$ —	$ —	$ 228,611
Midstream services revenues	—	20,983	—	(17,329)	3,654
Realized loss on derivatives	(1,661)	—	—	—	(1,661)
Unrealized gain on derivatives	33,821	—	—	—	33,821
Expenses[1]	146,416	10,462	31,608	(17,329)	171,157
Operating income (loss)[2]	$ 113,296	$ 11,580	$ (31,608)	$ —	$ 93,268
Total assets	$ 1,436,678	$ 192,889	$ 147,509	$ —	$ 1,777,076
Capital expenditures[3]	$ 373,956	$ 40,227	$ 3,216	$ —	$ 417,399

(1) Includes depletion, depreciation and amortization expenses of $72.1 million and $2.5 million for the exploration and production and midstream segments, respectively. Also includes corporate depletion, depreciation and amortization expenses of $0.7 million.

(2) Includes $5.1 million in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

(3) Includes $18.6 million in capital expenditures attributable to non-controlling interest in subsidiaries related to the midstream segment.

NOTE 12 - SEGMENT INFORMATION - Continued

	Exploration and Production	Midstream	Corporate	Consolidations and Eliminations	Consolidated Company
Six Months Ended June 30, 2016					
Oil and natural gas revenues	$112,672	$590	$—	$ —	$113,262
Midstream services revenues	—	5,560	—	(4,169)	1,391
Realized gain on derivatives	9,528	—	—	—	9,528
Unrealized loss on derivatives	(33,464)	—	—	—	(33,464)
Expenses[1]	267,365	3,096	26,665	(4,169)	292,957
Operating (loss) income[2]	$(178,629)	$3,054	$(26,665)	$ —	$(202,240)
Total assets	$927,557	$106,425	$52,106	$ —	$1,086,088
Capital expenditures	$162,116	$32,250	$3,582	$ —	$197,948

(1) Includes depletion, depreciation and amortization expenses of $58.9 million and $1.0 million for the exploration and production and midstream segments, respectively, and full-cost ceiling impairment expenses of $158.6 million for the exploration and production segment. Also includes corporate depletion, depreciation and amortization expenses of $0.3 million.

(2) Includes $93,000 in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

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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, 2016 (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 word 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, the sufficiency of our 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 our properties and capacity of transportation facilities, availability of acquisitions, our ability to integrate acquisitions 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 United States Securities and Exchange Commission, or 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 with our business;

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- our ability and the ability of our midstream joint venture to construct and operate midstream facilities, including the expansion of our Black River cryogenic natural gas processing plant and the drilling of additional salt water disposal wells;
- the ability of our midstream joint venture to attract third-party volumes;
- our costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;
- competition in the oil and natural gas industry, including in both the exploration and production and midstream segments;
- 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 or in our other filings with the SEC that are not historical.

Although we believe that the expectations conveyed by the forward-looking statements in this Quarterly Report are reasonable based on information available to us on the date hereof, 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 founded in July 2003 and 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. Additionally, we conduct midstream operations, primarily through our midstream joint venture, San Mateo Midstream, LLC (“San Mateo” or the “Joint Venture”), in support of our exploration, development and production operations and provide natural gas processing, natural gas, oil and salt water gathering services and salt water disposal services to third parties on a limited basis.

Second Quarter and Year-to-Date Highlights

For the three months ended June 30, 2017, our total oil equivalent production was 3.4 million BOE, and our average daily oil equivalent production was 36,922 BOE per day, of which 19,423 Bbl per day, or 53%, was oil and 105.0 MMcf per day, or 47%, was natural gas. Our oil production of 1.77 million Bbl for the three months ended June 30, 2017 increased 44% year-over-year from 1.23 million Bbl for the three months ended June 30, 2016. Our natural gas production of 9.6 Bcf for the three months ended June 30, 2017 increased 21% year-over-year from 7.9 Bcf for the three months ended June 30, 2016. For the six months ended June 30, 2017, our total oil equivalent production was 6.3 million BOE, and our average daily oil equivalent production was 34,972 BOE per day, of which 18,876 Bbl per day, or 54%, was oil and 96.6 MMcf per day, or 46%, was natural gas. Our oil production of 3.4 million Bbl for the six months ended June 30, 2017 increased 50% year-over-year from 2.3 million Bbl for the six months ended June 30, 2016. Our natural gas production of 17.5 Bcf for the six months ended June 30, 2017 increased 19% year-over-year from 14.7 Bcf for the six months ended June 30, 2016.

For the second quarter of 2017, we reported net income attributable to Matador Resources Company shareholders of approximately $28.5 million, or $0.28 per diluted common share on a GAAP basis, as compared to a net loss attributable to Matador Resources Company shareholders of $105.9 million, or $1.15 per diluted common share, for the second quarter of 2016. For the second quarter of 2017, our Adjusted EBITDA attributable to Matador Resources Company shareholders (“Adjusted EBITDA”), a non-GAAP financial measure, was $72.7 million, as compared to Adjusted EBITDA of $38.9 million during the second quarter of 2016. 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

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Measures.” For more information regarding our financial results for the second quarter of 2017, see “— Results of Operations” below.

For the six months ended June 30, 2017, we reported net income attributable to Matador Resources Company shareholders of approximately $72.5 million, or $0.72 per diluted common share on a GAAP basis, as compared to a net loss attributable to Matador Resources Company shareholders of $213.5 million, or $2.40 per diluted common share, for the six months ended June 30, 2016. For the six months ended June 30, 2017, our Adjusted EBITDA, a non-GAAP financial measure, was $142.6 million, as compared to Adjusted EBITDA of $56.1 million during the six months ended June 30, 2016. 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 2017, see “— Results of Operations” below.

During the second quarter of 2017, we continued our focus on the exploration, delineation and development of our Delaware Basin acreage in Loving County, Texas and Lea and Eddy Counties, New Mexico. We began 2017 operating four drilling rigs in the Delaware Basin and continued to do so throughout the first quarter of 2017. In late April 2017, we added a fifth drilling rig in the Delaware Basin and expect to operate five rigs in the Delaware Basin throughout the remainder of 2017, including three rigs in our Rustler Breaks and Antelope Ridge asset areas, one rig in our Wolf and Jackson Trust asset areas and one rig in our Ranger/Arrowhead and Twin Lakes asset areas. We expect to direct over 90% of our estimated 2017 capital expenditure budget (excluding capital expenditures related to acreage, mineral and seismic data acquisitions) to drilling and completion and midstream activities in the Delaware Basin. At June 30, 2017, we had incurred approximately $241 million, or 51%, of our 2017 capital expenditure budget of between $456 and $484 million (excluding capital expenditures related to acreage, mineral and seismic data acquisitions).

In July 2017, we took delivery of a sixth drilling rig on a temporary basis for the purpose of drilling a second salt water disposal well in the Rustler Breaks asset area for San Mateo. Upon delivery of the sixth drilling rig, the salt water disposal well was not ready to spud, so at August 2, 2017, we were using this rig to drill an additional oil and natural gas well in our Rustler Breaks asset area. At August 2, 2017, we had no plans to use this sixth rig to drill additional oil and natural gas wells for the remainder of 2017.

We also finished drilling our five-well program in the Eagle Ford shale in South Texas during the second quarter of 2017. Two of these wells were completed and turned to sales in mid-June 2017. The other three wells were completed and turned to sales in early July 2017, and thus, did not contribute to second quarter 2017 production volumes. The rig used to drill these five wells was released in May 2017, and we have no additional operated drilling activities planned in the Eagle Ford shale for the remainder of 2017.

We completed and turned to sales a total of 21 gross (14.2 net) wells in the Delaware Basin during the second quarter of 2017, including 16 gross (13.5 net) operated and five gross (0.7 net) non-operated horizontal wells. In the Rustler Breaks asset area, we began producing oil and natural gas from a total of 13 gross (8.2 net) wells during the second quarter of 2017, including nine gross (7.6 net) operated and four gross (0.6 net) non-operated wells. Of the nine gross operated wells in the Rustler Breaks asset area, five were Wolfcamp A-XY completions, one was a Wolfcamp A-Lower completion and three were Wolfcamp B-Blair completions. In addition, we began producing oil and natural gas from five gross (4.2 net) operated wells in the Wolf asset area during the second quarter of 2017, including one Wolfcamp A-XY completion and four Second Bone Spring completions. In the Ranger, Arrowhead and Twin Lakes asset areas, we began producing oil and natural gas from a total of one gross (0.1 net) non-operated well, one gross (0.7 net) operated well and one gross (1.0 net) operated well, respectively, during the second quarter of 2017. The well in the Arrowhead asset area, a Second Bone Spring completion, and the well in the Twin Lakes asset area, a Wolfcamp D completion, were the first operated horizontal wells we had tested in their respective asset areas.

As a result of our ongoing drilling and completion operations in these asset areas, our Delaware Basin production has continued to increase over the past twelve months. Our total Delaware Basin production for the second quarter of 2017 was 27,622 BOE per day, consisting of 16,645 Bbl of oil per day and 65.9 MMcf of natural gas per day, a 90% increase from production of 14,525 BOE per day, consisting of 9,789 Bbl of oil per day and 28.4 MMcf of natural gas per day, in the second quarter of 2016. The Delaware Basin contributed approximately 86% of our daily oil production and approximately 63% of our daily natural gas production in the second quarter of 2017, as compared to approximately 72% of our daily oil production and approximately 33% of our daily natural gas production in the second quarter of 2016.

During the second quarter of 2017 and through August 2, 2017, we acquired approximately 8,300 net acres in the Delaware Basin, mostly in and around our existing acreage positions, including new leasing activities, acquisitions of small interests from mineral and working interest owners in our operated wells and acreage trades or term assignments with other operators. We incurred capital expenditures of approximately $28.0 million to acquire this additional acreage throughout the Delaware Basin, as well as for new 3-D seismic data across portions of our Wolf asset area. At August 2, 2017, we held approximately 189,500 gross (108,000 net) acres in the Permian Basin in Southeast New Mexico and West Texas, primarily in

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the Delaware Basin in Lea and Eddy Counties, New Mexico and Loving County, Texas. We plan to continue our leasing and acquisitions efforts in the Delaware Basin during the remainder of 2017 and may also continue acquiring acreage in the Eagle Ford and Haynesville shales 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, 2017, December 31, 2016 and June 30, 2016. 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, 2017	December 31, 2016	June 30, 2016
Estimated Proved Reserves Data: (1) (2)			
Estimated proved reserves:			
Oil (MBbl)(3)	74,954	56,977	52,337
Natural Gas (Bcf)(4)	356.5	292.6	258.7
Total (MBOE)(5)	134,373	105,752	95,457
Estimated proved developed reserves:			
Oil (MBbl)(3)	28,454	22,604	19,913
Natural Gas (Bcf)(4)	159.7	126.8	114.4
Total (MBOE)(5)	55,075	43,731	38,978
Percent developed	41.0 %	41.4 %	40.8 %
Estimated proved undeveloped reserves:			
Oil (MBbl)(3)	46,500	34,373	32,424
Natural Gas (Bcf)(4)	196.8	165.9	144.3
Total (MBOE)(5)	79,298	62,021	56,479
Standardized Measure(6) (in millions)	$1,001.9	$575.0	$468.3
PV-10(7) (in millions)	$1,086.9	$581.5	$473.2

(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 2016 through June 2017 were $45.42 per Bbl for oil and $3.01 per MMBtu for natural gas, for the period from January 2016 through December 2016 were $39.25 per Bbl for oil and $2.48 per MMBtu for natural gas and for the period from July 2015 through June 2016 were $39.63 per Bbl for oil and $2.24 per MMBtu for natural gas. These prices were adjusted by property for quality, energy content, regional price differentials, transportation fees, marketing deductions and other factors affecting the price received at the wellhead. We report our proved reserves in two streams, oil and natural gas, and the economic value of the natural gas liquids associated with the natural gas is

included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold.

(3) One thousand barrels of oil.

(4) One billion cubic feet of natural gas.

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

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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, 2017, December 31, 2016 and June 30, 2016 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, 2017, December 31, 2016 and June 30, 2016 were $85.0 million, $6.5 million and $4.9 million, respectively.

At June 30, 2017, our estimated total proved oil and natural gas reserves were 134.4 million BOE, including 75.0 million Bbl of oil and 356.5 Bcf of natural gas, with a Standardized Measure of $1,001.9 million and a PV-10, a non-GAAP financial measure, of $1,086.9 million. At December 31, 2016, our estimated total proved oil and natural gas reserves were 105.8 million BOE, including 57.0 million Bbl of oil and 292.6 Bcf of natural gas, and at June 30, 2016, our estimated total proved oil and natural gas reserves were 95.5 million BOE, including 52.3 million Bbl of oil and 258.7 Bcf of natural gas. Our proved oil reserves of 75.0 million Bbl at June 30, 2017 increased 32%, as compared to 57.0 million Bbl at December 31, 2016, and increased 43%, as compared to 52.3 million Bbl at June 30, 2016. At June 30, 2017, approximately 41% of our total proved reserves were proved developed reserves, 56% of our total proved reserves were oil and 44% of our total proved reserves were natural gas.

As a result of our drilling, completion and delineation activities in Southeast New Mexico and West Texas since 2014, our Delaware Basin oil and natural gas reserves have become a more significant component of our total oil and natural gas reserves. Our estimated Delaware Basin proved oil and natural gas reserves increased 63% from 66.2 million BOE at June 30, 2016, 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, to 108.1 million BOE, or 80% of our total proved oil and natural gas reserves, including 64.9 million Bbl of oil and 259.2 Bcf of natural gas, at June 30, 2017.

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 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,	
	2017	2016	2017	2016
Operating Data:				
Revenues (in thousands):[1]				
Oil	$81,322	$52,691	$164,958	$82,849
Natural gas	32,442	16,645	63,653	30,413
Total oil and natural gas revenues	113,764	69,336	228,611	113,262
Third-party midstream services revenues[2]	2,099	918	3,654	1,391
Realized gain (loss) on derivatives	558	2,465	(1,661)	9,528
Unrealized gain (loss) on derivatives	13,190	(26,625)	33,821	(33,464)
Total revenues	$129,611	$46,094	$264,425	$90,717
Net Production Volumes:[1]				
Oil (MBbl)[3]	1,767	1,230	3,417	2,274
Natural gas (Bcf)[4]	9.6	7.9	17.5	14.7
Total oil equivalent (MBOE)[5]	3,360	2,550	6,330	4,720
Average daily production (BOE/d)[6]	36,922	28,022	34,972	25,934
Average Sales Prices:				
Oil, without realized derivatives (per Bbl)	$46.01	$42.84	$48.28	$36.43
Oil, with realized derivatives (per Bbl)	$46.34	$43.29	$47.97	$39.08
Natural gas, without realized derivatives (per Mcf)	$3.40	$2.10	$3.64	$2.07
Natural gas, with realized derivatives (per Mcf)	$3.39	$2.34	$3.61	$2.31

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

(2) Reclassified from other income for the three and six months ended June 30, 2016 due to the midstream segment becoming a reportable segment.

(3) One thousand barrels of oil.

(4) One billion cubic feet of natural gas.

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

(6) 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, 2017 as Compared to Three Months Ended June 30, 2016

Oil and natural gas revenues. Our oil and natural gas revenues increased $44.4 million to $113.8 million, or 64%, for the three months ended June 30, 2017, as compared to $69.3 million for the three months ended June 30, 2016. Our oil revenues increased $28.6 million, or 54%, to $81.3 million for the three months ended June 30, 2017, as compared to $52.7 million for the three months ended June 30, 2016. The increase in oil revenues resulted from (i) a higher weighted average oil price realized for the three months ended June 30, 2017 of $46.01 per Bbl, as compared to $42.84 per Bbl realized for the three months ended June 30, 2016, and (ii) the 44% increase in oil production to 1.77 million Bbl of oil for the three months ended June 30, 2017, or about 19,423 Bbl of oil per day, as compared to 1.23 million Bbl of oil, or about 13,516 Bbl of oil per day, for the three months ended June 30, 2016. The increase in oil production is primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin. Our natural gas revenues increased by $15.8 million, or 95%, to $32.4 million for the three months ended June 30, 2017, as compared to $16.6 million for the three months ended June 30, 2016. The increase in natural gas revenues resulted from (i) a higher weighted average natural gas price realized for the three months ended June 30, 2017 of

$3.40 per Mcf, as compared to $2.10 per Mcf realized for the three months ended June 30, 2016, and (ii) the 21% increase in our natural gas production to 9.6 Bcf for the three months ended June 30, 2017, as compared to 7.9 Bcf for the three months ended June 30, 2016. The increase in natural gas production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin.

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Third-party midstream services revenues. Our third-party midstream services revenues increased to $2.1 million, or 129%, for the three months ended June 30, 2017, as compared to $0.9 million for the three months ended June 30, 2016. This increase was primarily attributable to a significant increase in natural gas gathering and processing revenues to approximately $1.6 million for the three months ended June 30, 2017, as compared to $0.3 million for the three months ended June 30, 2016, due to (i) our natural gas gathering system and the Black River cryogenic natural gas processing plant (the “Black River Processing Plant”) in the Rustler Breaks asset area being placed into service in the second half of 2016 and (ii) increased natural gas production in our Wolf asset area.

Realized gain on derivatives. Our realized net gain on derivatives was $0.6 million for the three months ended June 30, 2017, as compared to a realized net gain of $2.5 million for the three months ended June 30, 2016. We realized a net gain of $0.6 million from our oil derivative contracts for the three months ended June 30, 2017, resulting from oil prices below the floor prices of certain of our oil costless collar contracts. We realized net 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, resulting from oil and natural gas prices below the floor prices of the majority of our oil and natural gas costless collar contracts. We realized an average gain of approximately $0.47 per Bbl hedged on all of our open oil costless collar contracts during the three months ended June 30, 2017, as compared to an average gain of $0.81 per Bbl hedged for the three months ended June 30, 2016. Our oil volumes hedged for the three months ended June 30, 2017 were 78% higher as compared to the three months ended June 30, 2016. We realized an average gain of approximately $0.65 per MMBtu hedged on all of our open natural gas costless collar contracts for the three months ended June 30, 2016. Our total natural gas volumes hedged for the three months ended June 30, 2017 were 109% higher than the total natural gas volumes hedged for the three months ended June 30, 2016.

Unrealized gain (loss) on derivatives. Our unrealized net gain on derivatives was $13.2 million for the three months ended June 30, 2017, as compared to an unrealized net loss of $26.6 million for the three months ended June 30, 2016. During the three months ended June 30, 2017, the aggregate net fair value of our open oil and natural gas derivative contracts increased to an asset of approximately $8.9 million from a liability of $4.3 million at March 31, 2017, resulting in an unrealized net gain on derivatives of $13.2 million for the three months ended June 30, 2017. 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.

Six Months Ended June 30, 2017 as Compared to Six Months Ended June 30, 2016

Oil and natural gas revenues. Our oil and natural gas revenues increased $115.3 million to $228.6 million, or 102%, for the six months ended June 30, 2017, as compared to $113.3 million for the six months ended June 30, 2016. Our oil revenues increased $82.1 million, or 99%, to $165.0 million for the six months ended June 30, 2017, as compared to $82.8 million for the six months ended June 30, 2016. The increase in oil revenues resulted from (i) a higher weighted average oil price realized for the six months ended June 30, 2017 of $48.28 per Bbl, as compared to $36.43 per Bbl realized for the six months ended June 30, 2016, and (ii) the 50% increase in oil production to 3.42 million Bbl of oil in the six months ended June 30, 2017, or about 18,876 Bbl of oil per day, as compared to 2.27 million Bbl of oil, or about 12,495 Bbl of oil per day, in the six months ended June 30, 2016. This increased oil production is primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin. Our natural gas revenues increased by $33.2 million, or 109%, to $63.7 million for the six months ended June 30, 2017, as compared to $30.4 million for the six months ended June 30, 2016. The increase in natural gas revenues resulted from (i) a higher weighted average natural gas price realized for the six months ended June 30, 2017 of $3.64 per Mcf, as compared to $2.07 per Mcf realized for the six months ended June 30, 2016, and (ii) the 19% increase in our natural gas production to 17.5 Bcf for the six months ended June 30, 2017, as compared to 14.7 Bcf for the six months ended June 30, 2016. The increase in natural gas production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin.

Third-party midstream services revenues. Our third-party midstream services revenues increased to $3.7 million, or 163%, for the six months ended June 30, 2017, as compared to $1.4 million for the six months ended June 30, 2016. This increase was primarily attributable to a significant increase in natural gas gathering and processing revenues to approximately $2.8 million for the six months ended June 30, 2017, as compared to $0.7 million for the six months ended June 30, 2016, due to (i) our natural gas gathering system and the Black River Processing Plant in the Rustler Breaks asset area being placed into service in the second half of 2016 and (ii) increased natural gas production in our Wolf asset area.

Realized gain (loss) on derivatives. Our realized net loss on derivatives was $1.7 million for the six months ended June 30, 2017, as compared to a net gain of approximately $9.5 million for the six months ended June 30, 2016. We realized net losses of $1.1 million and $0.6 million from our oil and natural gas derivative contracts, respectively, for the six months ended June 30, 2017, resulting from oil and natural gas prices that were above the ceiling prices of certain of our oil and natural gas costless collar contracts. We realized net gains of $6.0 million and $3.5 million from our oil and natural gas derivative contracts, respectively, for the six months ended June 30, 2016, resulting from oil and natural gas prices below the floor prices of the majority of our oil and natural gas costless collar contracts. We realized an average loss of approximately $0.48 per Bbl hedged on all of our open oil costless collar contracts during the six months ended June 30, 2017, as compared to an average gain of $5.11 per Bbl hedged for the six months ended June 30, 2016. Our oil volumes hedged for the three months ended June 30, 2017 were 86% higher as

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compared to the six months ended June 30, 2016. We realized an average loss of approximately $0.05 per MMBtu hedged on all of our open natural gas costless collar contracts during the six months ended June 30, 2017, as compared to an average gain of approximately $0.61 per MMBtu hedged on all of our open natural gas costless collar contracts for the six months ended June 30, 2016. Our total natural gas volumes hedged for the six months ended June 30, 2017 were 102% higher than the total natural gas volumes hedged for the six months ended June 30, 2016.
Unrealized gain (loss) on derivatives. Our unrealized gain on derivatives was approximately $33.8 million for the six months ended June 30, 2017, as compared to an unrealized loss of approximately $33.5 million for the six months ended June 30, 2016. During the period from December 31, 2016 through June 30, 2017, the aggregate net fair value of our open oil and natural gas derivative contracts increased from a liability of approximately $25.0 million to an asset of approximately $8.9 million, resulting in an unrealized gain on derivatives of approximately $33.8 million for the six months ended June 30, 2017. This gain is primarily attributable to the decrease in oil and natural gas futures prices during the six months ended June 30, 2017. 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.

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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)	2017	2016	2017	2016
Expenses:				
Production taxes, transportation and processing	$12,875	$10,556	$24,682	$18,459
Lease operating (1)	16,040	12,183	31,797	26,695
Plant and other midstream services operating	2,942	1,061	5,283	2,088
Depletion, depreciation and amortization	41,274	31,248	75,266	60,170
Accretion of asset retirement obligations	314	289	614	552
Full-cost ceiling impairment	—	78,171	—	158,633
General and administrative	17,177	13,197	33,515	26,360
Total expenses	$90,622	$146,705	$171,157	$292,957
Operating income (loss)	$38,989	$(100,611)	$93,268	$(202,240)
Other income (expense):				
Net gain on asset sales and inventory impairment	$—	$1,002	$7	$2,067
Interest expense	(9,224)	(6,167)	(17,679)	(13,365)
Other income (2)	1,922	29	1,991	124
Total other expense	$(7,302)	$(5,136)	$(15,681)	$(11,174)
Net income (loss)	$31,687	$(105,747)	$77,587	$(213,414)
Net income attributable to non-controlling interest in subsidiaries	(3,178)	(106)	(5,094)	(93)
Net income (loss) attributable to Matador Resources Company shareholders	$28,509	$(105,853)	$72,493	$(213,507)
Expenses per BOE:				
Production taxes, transportation and processing	$3.83	$4.14	$3.90	$3.91
Lease operating (1)	$4.77	$4.78	$5.02	$5.66
Plant and other midstream services operating	$0.88	$0.42	$0.83	$0.44
Depletion, depreciation and amortization	$12.28	$12.25	$11.89	$12.75
General and administrative	$5.11	$5.18	$5.29	$5.58

(1) $1.1 million, or $0.42 per BOE, and $2.1 million, or $0.44 per BOE, was reclassified to plant and other midstream services operating expenses for the three and six months ended June 30, 2016, respectively, due to our midstream business becoming a reportable segment.

(2) $0.9 million and $1.4 million was reclassified to midstream services revenues for the three and six months ended June 30, 2016, respectively, due to our midstream business becoming a reportable segment.

Three Months Ended June 30, 2017 as Compared to Three Months Ended June 30, 2016

Production taxes, transportation and processing. Our production taxes, transportation and processing expenses increased by $2.3 million to $12.9 million, or 22%, for the three months ended June 30, 2017, as compared to $10.6 million for the three months ended June 30, 2016. The increase in production taxes, transportation and processing expenses was primarily attributable to the increase in our production taxes of $3.1 million to $6.9 million for the three months ended June 30, 2017, as compared to $3.9 million for the three months ended June 30, 2016, primarily due to the 64% increase in oil and natural gas revenues for the three months ended June 30, 2017, as compared to the three months ended June 30, 2016. In addition, the production tax rates in New Mexico are higher than production tax rates in Texas. As more of our oil and natural gas production becomes attributable to New Mexico, we expect to continue to experience increased production tax expenses. The increased production taxes were partially offset by a decrease in transportation and processing expenses. Transportation and processing expenses decreased to $5.9 million for the three months ended June 30, 2017, as compared to transportation and processing expenses of $6.7 million for the three months ended June 30, 2016. This decrease of $0.8 million was primarily due to the start-up in late August 2016 of the Black River Processing Plant, which processes most of the natural gas produced in our Rustler Breaks asset area in Eddy County, New Mexico, and the 34% decrease in natural gas production between the two periods in Northwest Louisiana and East Texas where our transportation and processing charges are highest on a unit-of-production basis. On a unit-of-production basis, our production taxes, transportation and processing expenses decreased 7% to $3.83 per BOE for the three months ended June 30, 2017, as compared to $4.14 per BOE for the three months ended June 30, 2016. On a unit of-production basis, these second quarter 2017 expenses benefited from significantly higher total oil equivalent production, which increased 32% in the second quarter of 2017, as compared to the second quarter of 2016.

Lease operating. Our lease operating expenses increased by $3.9 million to $16.0 million, or an increase of 32%, for the three months ended June 30, 2017, as compared to $12.2 million for the three months ended June 30, 2016. Our lease operating expenses on a unit-of-production basis remained consistent at $4.77 per BOE for the three months ended June 30, 2017, as compared to $4.78 per BOE for the three months ended June 30, 2016. Our total oil equivalent production increased 32% to approximately 3.4 million BOE for the three months ended June 30, 2017 from approximately 2.6 million BOE for the three months ended June 30, 2016. The increase in lease operating expenses on an absolute basis for the three months ended June 30, 2017, as compared to the three months ended June 30, 2016, was primarily attributable to an increase in costs of services and equipment related to the increased number of wells at June 30, 2017, as compared to June 30, 2016, as a result of our increased delineation and development activities in the Delaware Basin.

Plant and other midstream services operating. Our plant and other midstream services operating expenses increased by $1.9 million to $2.9 million, an increase of 177%, for the three months ended June 30, 2017, as compared to $1.1 million for the three months ended June 30, 2016. This increase was partially attributable to the expenses associated with our salt water disposal operations of $1.5 million for the three months ended June 30, 2017, as compared to $0.7 million for the three months ended June 30, 2016, as a result of additional salt water disposal wells operating in the second quarter of 2017. Most of the remaining increase was attributable to expenses of $0.8 million associated with the Black River Processing Plant, which began operating in August 2016.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $10.0 million to $41.3 million, or an increase of 32%, for the three months ended June 30, 2017, as compared to $31.2 million for the three months ended June 30, 2016. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased slightly to $12.28 per BOE for the three months ended June 30, 2017, as compared to $12.25 per BOE for the three months ended June 30, 2016. The increase in our total depletion, depreciation and amortization expenses was primarily attributable to (i) increased well costs, largely as a result of increased well stimulation costs, since December 31, 2016, and (ii) the 32% increase in oil and natural gas production to 3.4 million BOE for the three months ended June 30, 2017, as compared to 2.6 million BOE for the three months ended June 30, 2016. The impact of the increase in well costs and oil and natural gas production on depletion, depreciation and amortization was mostly offset by higher total proved reserves of 134.4 million BOE, or an increase of 41%, at June 30, 2017, as compared to total proved reserves of 95.5 million BOE at June 30, 2016. The 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. In addition, depreciation expenses attributable to our midstream segment were approximately $1.3 million for the three months ended June 30, 2017, as compared to $0.5 million for the three months ended June 30, 2016.

Full-cost ceiling impairment. At June 30, 2017, we recorded no impairment charge to the net capitalized costs of our oil and natural gas properties. We recorded an impairment charge of $78.2 million to the net capitalized costs of our oil and natural gas properties for the three months ended June 30, 2016.

General and administrative. Our general and administrative expenses increased $4.0 million to $17.2 million, an increase of 30%, for the three months ended June 30, 2017, as compared to $13.2 million for the three months ended June 30, 2016. The increase in our general and administrative expenses was attributable to the $3.7 million increase in non-cash stock-based compensation expense to $7.0 million for the three months ended June 30, 2017, as compared to $3.3 million for the three months ended June 30, 2016. The increase in our general and administrative expenses was also attributable to increased payroll expenses of approximately $1.4 million associated with additional employees joining the Company to support our increased land, geoscience, drilling, completion, production, midstream, accounting and administration functions as a result of the continued growth of the Company. The increase in our non-cash stock-based compensation was attributable to the increased expense related to the continued vesting of awards granted from 2013 through 2017 and the granting of new awards during the second quarter of 2017, as well as a change in the vesting schedule applicable to equity awards granted to our board of directors resulting in a $1.5

million one-time stock-based compensation expense. These increases were partially offset by the increase in capitalized general and administrative expense of $1.3 million due to our increased delineation and development activities in the Delaware Basin for the three months ended June 30, 2017, as compared to the three months ended June 30, 2016. As a result, our general and administrative expenses decreased 1% on a unit-of-production basis to $5.11 per BOE for the three months ended June 30, 2017, as compared to $5.18 per BOE for the three months ended June 30, 2016.

Interest expense. For the three months ended June 30, 2017, we incurred total interest expense of approximately $11.1 million. We capitalized approximately $1.9 million of our interest expense on certain qualifying projects for the three months ended June 30, 2017 and expensed the remaining $9.2 million to operations. For the three months ended June 30, 2016, we incurred total interest expense of approximately $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 to operations. The increase in total interest expense of $3.3 million for the three months ended June 30, 2017, as compared to the three months ended June 30,

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2016, was attributable to an increase in the average debt outstanding. At June 30, 2017, we had no borrowings outstanding and $0.8 million in letters of credit outstanding under our revolving credit agreement (the "Credit Agreement") and $575.0 million in outstanding senior notes. 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 senior notes.

Total income tax benefit. Our deferred tax assets exceeded our deferred tax liabilities at June 30, 2017 due to the deferred tax amounts generated by the full-cost ceiling impairment charges recorded in prior periods. As a result, we established a valuation allowance against the deferred tax assets beginning in the third quarter of 2015. We retained a full valuation allowance at June 30, 2017 due to uncertainties regarding the future realization of our deferred tax assets.

Six Months Ended June 30, 2017 as Compared to Six Months Ended June 30, 2016

Production taxes, transportation and processing. Our production taxes, transportation and processing expenses increased by approximately $6.2 million to $24.7 million, or 34%, for the six months ended June 30, 2017, as compared to $18.5 million for the six months ended June 30, 2016. On a unit-of-production basis, our production taxes, transportation and processing expenses remained consistent at $3.90 per BOE for the six months ended June 30, 2017, as compared to $3.91 per BOE for the six months ended June 30, 2016. The increase in production taxes, transportation and processing expenses was primarily attributable to the $8.0 million increase in our production taxes to $14.1 million for the six months ended June 30, 2017, as compared to $6.1 million for the six months ended June 30, 2016, primarily due to the $115.3 million increase in oil and natural gas revenues for the six months ended June 30, 2017, as compared to the six months ended June 30, 2016. In addition, the production tax rates in New Mexico are higher than production tax rates in Texas. As more of our oil and natural gas production becomes attributable to New Mexico, we expect to continue to experience increased production tax expenses. The increased production taxes were partially offset by a decrease in transportation and processing expenses. Transportation and processing expenses decreased to $10.6 million for the six months ended June 30, 2017, as compared to transportation and processing expenses of $12.4 million for the six months ended June 30, 2016. This decrease of $1.8 million was primarily due to the start-up in late August 2016 of the Black River Processing Plant, which processes most of the natural gas produced in our Rustler Breaks asset area in Eddy County, New Mexico, and the 36% decrease in natural gas production between the two periods in Northwest Louisiana and East Texas where our transportation and processing charges are highest on a unit-of-production basis. On a unit-of-production basis, the expenses for the six months ended June 30, 2017 also benefited from significantly higher total oil equivalent production, which increased 34% in the six months ended June 30, 2017, as compared to the six months ended June 30, 2016.

Lease operating. Our lease operating expenses increased by $5.1 million to $31.8 million, or 19%, for the six months ended June 30, 2017, as compared to $26.7 million for the six months ended June 30, 2016. Our lease operating expenses unit-of-production basis decreased 11% to $5.02 per BOE for the six months ended June 30, 2017, as compared to $5.66 per BOE for the six months ended June 30, 2016. The decrease achieved in lease operating expenses on a unit-of-production basis was attributable to several key factors, including (i) decreased costs associated with our Eagle Ford operations, including workover, salt water disposal and chemical costs, (ii) additional salt water disposal and gathering capacity added in both the Wolf and Rustler Breaks asset areas and (iii) increased oil equivalent production as compared to the six months ended June 30, 2016. This decrease was partially offset by increased workover expenses in the Wolf asset area during the six months ended June 30, 2017.

Plant and other midstream services operating. Our plant and other midstream services operating expenses increased by $3.2 million to $5.3 million, an increase of 153%, for the six months ended June 30, 2017, as compared to $2.1 million for the six months ended June 30, 2016. This increase was partially attributable to the expenses associated with our salt water disposal operations of $3.0 million for the six months ended June 30, 2017, as compared to $1.6 million for the six months ended June 30, 2016, as a result of additional salt water disposal wells operating in the second quarter of 2017. The remaining increase was attributable to expenses of $1.8 million associated with the Black River Processing Plant, which began operating in August 2016.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $15.1 million to $75.3 million, or 25%, for the six months ended June 30, 2017, as compared to $60.2 million for the six months ended June 30, 2016. On a unit-of-production basis, our depletion, depreciation and amortization expenses decreased 7% to $11.89 per BOE for the six months ended June 30, 2017, as compared to $12.75 per BOE for the six months ended June 30, 2016. The increase in our total depletion, depreciation and amortization expenses was primarily attributable to (i) increased well costs, largely as a result of increased well stimulation costs, since December 31, 2016, and (ii) the 34% increase in oil and natural gas production to 6.3 million BOE for the six months ended June 30, 2017, as compared to 4.7 million BOE for the six months ended June 30, 2016. The decrease in our depletion, depreciation and amortization expenses on a unit-of-production basis was attributable to (i) the impairment charges recorded in 2016 and (ii) higher total proved reserves of 134.4 million BOE, or an increase of 41%, at June 30, 2017, as compared to total proved reserves of 95.5 million BOE at June 30, 2016. The 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. In addition, depreciation expenses attributable to our midstream segment were approximately $2.5 million for the six months ended June 30, 2017, as compared to $1.0 million for the six months ended June 30, 2016.

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Full-cost ceiling impairment. At June 30, 2017, we recorded no impairment charge to the net capitalized costs of our oil and natural gas properties. 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.

General and administrative. Our general and administrative expenses increased $7.2 million to $33.5 million, an increase of 27%, for the six months ended June 30, 2017, as compared to $26.4 million for the six months ended June 30, 2016. The increase in our general and administrative expenses was attributable to the $5.6 million increase in non-cash stock-based compensation expense to $11.2 million for the six months ended June 30, 2017, as compared to $5.6 million for the six months ended June 30, 2016. The increase in our non-cash stock-based compensation was attributable to the increased expense related to the vesting of awards granted from 2013 through 2017 and the granting of new awards during the second quarter of 2017, as well as a change in the vesting schedule applicable to equity awards granted to our board of directors resulting in a $1.5 million one-time stock-based compensation expense. The increase in our general and administrative expenses was also attributable to transaction costs of approximately $3.5 million related to the formation of San Mateo and increased payroll expenses of approximately $4.0 million associated with additional employees joining the Company to support our increased land, geoscience, drilling, completion, production, midstream, accounting and administration functions as a result of the continued growth of the Company. These increases were partially offset by the increase in capitalized general and administrative expenses of $4.9 million due to our increased delineation and development activities in the Delaware Basin for the six months ended June 30, 2017, as compared to the six months ended June 30, 2016. Our general and administrative expenses decreased 5% on a unit-of-production basis to $5.29 per BOE for the six months ended June 30, 2017, as compared to $5.58 per BOE for the six months ended June 30, 2016, primarily due to our increased total oil equivalent production.

Interest expense. For the six months ended June 30, 2017, we incurred total interest expense of approximately $20.8 million. We capitalized approximately $3.2 million of our interest expense on certain qualifying projects for the six months ended June 30, 2017 and expensed the remaining $17.7 million to operations. For the six months ended June 30, 2016, we incurred total interest expense of approximately $15.6 million. We capitalized $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 to operations. The increase in total interest expense of $5.3 million for the six months ended June 30, 2017, as compared to the six months ended June 30, 2016, was attributable to an increase in the average debt outstanding. At June 30, 2017, we had no borrowings outstanding and $0.8 million in letters of credit outstanding under our Credit Agreement and $575.0 million in outstanding senior notes. 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 senior notes.

Total income tax benefit. Our deferred tax assets exceeded our deferred tax liabilities at June 30, 2017 due to the deferred tax amounts generated by the full-cost ceiling impairment charges recorded in prior periods. As a result, we established a valuation allowance against the deferred tax assets beginning in the third quarter of 2015. We retained a full valuation allowance at June 30, 2017 due to uncertainties regarding the future realization of our deferred tax assets.

Liquidity and Capital Resources

Our primary use of capital has been, and we expect will continue to be during the remainder of 2017 and for the foreseeable future, for the acquisition, exploration and development of oil and natural gas properties and for midstream investments. Excluding any possible significant acquisitions, we expect to fund our capital expenditure requirements through the remainder of 2017 with a combination of cash on hand (including proceeds we received in connection with the formation of the Joint Venture), 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, the sale or joint venture of midstream assets or oil and natural gas producing assets or acreage, particularly in our non-core asset areas, as well as potential issuances of equity, debt or convertible securities, none of which may be available on satisfactory terms or at all. 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.

On February 17, 2017, we announced the formation of San Mateo, a strategic joint venture with Five Point to operate and expand our Delaware Basin midstream assets. We received $171.5 million in connection with the formation of the Joint Venture and may earn up to an additional $73.5 million in performance incentives over the next five years. We continue to operate the Delaware Basin midstream assets and retain operational control of the Joint Venture. The Company and Five Point own 51% and 49% of the Joint Venture, respectively. San Mateo will continue to provide firm capacity service to us at market rates, while also being a midstream service provider to third parties in and around our Wolf and Rustler Breaks asset areas.

We expect that development of our Delaware Basin assets will be the primary focus of our operations and capital expenditures for the remainder of 2017. We operated five contracted drilling rigs in the Delaware Basin and one contracted drilling rig in the Eagle Ford during the second quarter of 2017. Our 2017 estimated capital expenditure budget consists of $400 to $420 million for drilling, completions, facilities and infrastructure and $56 to $64 million for midstream capital expenditures, which represents our 51% share of an estimated 2017 capital expenditure budget of $110 to $125 million for San Mateo. We

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have allocated substantially all of our estimated 2017 capital expenditures to the further delineation and development of our growing leasehold position and midstream assets in the Delaware Basin, with the exception of amounts allocated to limited operations in the Eagle Ford (including the five wells drilled and completed in 2017) and Haynesville shales to maintain and extend leases and to participate in certain non-operated well opportunities. For the remainder of 2017, our Delaware Basin drilling program will continue to focus on the development of the Wolf and Rustler Breaks asset areas and the further delineation and development of the Jackson Trust, Ranger/Arrowhead, Antelope Ridge and Twin Lakes asset areas, although we may also continue to delineate previously untested zones in the Wolf and Rustler Breaks asset areas.

During the second quarter of 2017 and through August 2, 2017, we acquired approximately 8,300 net acres in the Delaware Basin, mostly in and around our existing acreage positions, including new leasing activities, acquisitions of small interests from mineral and working interest owners in our operated wells and acreage trades or term assignments with other operators. We incurred capital expenditures of approximately $28.0 million to acquire this additional acreage throughout the Delaware Basin, as well as for new 3-D seismic data across portions of our Wolf asset area. At August 2, 2017, we held approximately 189,500 gross (108,000 net) acres in the Permian Basin in Southeast New Mexico and West Texas, primarily in the Delaware Basin in Lea and Eddy Counties, New Mexico and Loving County, Texas.

We plan to continue our leasing and acquisitions efforts in the Delaware Basin during the remainder of 2017 and may also continue acquiring acreage in the Eagle Ford and Haynesville shales. These expenditures are opportunity-specific and per-acre prices can vary significantly based on the opportunity. As a result, it is difficult to estimate these 2017 capital expenditures with any degree of certainty; therefore, we have not provided estimated capital expenditures related to acreage and mineral acquisitions for the remainder of 2017.

At June 30, 2017, we had cash totaling approximately $131.5 million and restricted cash totaling approximately $15.0 million, most of which is associated with San Mateo. By contractual agreement, the cash in the accounts held by our less-than-wholly-owned subsidiaries is not to be commingled with other Company cash and is to be used only to fund the capital expenditures and operations of these less-than-wholly-owned subsidiaries. Additionally, at June 30, 2017, we had no outstanding borrowings under our Credit Agreement, which has a borrowing base of $450.0 million and an elected commitment of $400.0 million.

Our 2017 capital expenditures may be adjusted as business conditions warrant and the amount, timing and allocation of such 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 and scope of our midstream activities, including the expansion of the Black River Processing Plant, the ability of our Joint Venture partner to meet its capital obligations, other opportunities that may become available to us and our ability to obtain capital. When oil or natural gas prices decline, 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 2017 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 Northwest 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 2017 and the hedges we currently have in place. We use commodity derivative financial instruments at times 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. As of August 2, 2017, we had approximately 65% of our anticipated oil production and approximately 70% of our anticipated natural gas production hedged for the remainder of 2017. 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, 2017.

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Our unaudited cash flows for the six months ended June 30, 2017 and 2016 are presented below:

	Six Months Ended June 30,	
(In thousands)	2017	2016
Net cash provided by operating activities	$121,242	$49,600
Net cash used in investing activities	(383,478)	(166,032)
Net cash provided by financing activities	180,818	140,573
Net change in cash	$(81,418)	$24,141
Adjusted EBITDA[(1)] attributable to Matador Resources Company shareholders	$142,611	$56,145

(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 increased $71.6 million to $121.2 million for the six months ended June 30, 2017 from $49.6 million for the six months ended June 30, 2016. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased to $130.9 million for the six months ended June 30, 2017 from $43.5 million for the six months ended June 30, 2016. This increase was primarily attributable to higher oil and natural gas production and higher commodity prices and was partially offset by the decrease in our realized gains on derivatives and an increase in certain expenses. Changes in our operating assets and liabilities between the two periods resulted in a net decrease of approximately $15.8 million in net cash provided by operating activities for the six months ended June 30, 2017, as compared to 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 increased by $217.4 million to $383.5 million for the six months ended June 30, 2017 from $166.0 million for the six months ended June 30, 2016. This increase in net cash used in investing activities is primarily due to an increase of $166.5 million in oil and natural gas properties capital expenditures for the six months ended June 30, 2017, as compared to the six months ended June 30, 2016. Cash used for oil and natural gas properties capital expenditures for the six months ended June 30, 2017 was primarily attributable to the acquisition of additional leasehold and mineral interests and our operated drilling and completion activities in the Delaware Basin. A small portion of our capital expenditures for the six months ended June 30, 2017 was directed to our participation in non-operated wells and our operated drilling and completion activities in the Eagle Ford shale. Additionally, there was an increase in cash outflows related to restricted cash of approximately $57.7 million between the two periods. These increases were partially offset by a decrease in cash used for other property and equipment of approximately $5.8 million.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities increased by $40.2 million to $180.8 million for the six months ended June 30, 2017 from $140.6 million for the six months ended June 30, 2016. The increase in net cash provided by financing activities for the six months ended June 30, 2017 was primarily attributable to (i) the increase of $171.5 million related to contributions from the formation of the Joint Venture and (ii) the net increase of $12.7 million related to contributions from and distributions to the non-controlling interest owners of less-than-wholly-owned subsidiaries, which were offset by (x) an increase in cash outflows of $2.7 million related to the purchase of the non-controlling interest of a less-than-wholly-owned subsidiary and (y) an increase in cash outflows of $2.0 million related to taxes paid in connection with the net share settlement of stock-based compensation. The net cash provided by financing activities for the six months ended June 30, 2016 was primarily attributable to the net proceeds from our March 2016 equity offering of $142.4 million ($141.6 million including cost to issue equity).

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 senior notes.

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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 a primary 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 income (loss) and net cash provided by operating activities, respectively.

	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands)	2017	2016	2017	2016
Unaudited Adjusted EBITDA Reconciliation to Net Income (Loss):				
Net income (loss) attributable to Matador Resources Company shareholders	$28,509	$(105,853)	$72,493	$(213,507)
Net income attributable to non-controlling interest in subsidiaries	3,178	106	5,094	93
Net income (loss)	31,687	(105,747)	77,587	(213,414)
Interest expense	9,224	6,167	17,679	13,365
Depletion, depreciation and amortization	41,274	31,248	75,266	60,170
Accretion of asset retirement obligations	314	289	614	552
Full-cost ceiling impairment	—	78,171	—	158,633
Unrealized (gain) loss on derivatives	(13,190)	26,625	(33,821)	33,464
Stock-based compensation expense	7,026	3,310	11,192	5,553
Net gain on asset sales and inventory impairment	—	(1,002)	(7)	(2,067)
Consolidated Adjusted EBITDA	76,335	39,061	148,510	56,256
Adjusted EBITDA attributable to non-controlling interest in subsidiaries	(3,683)	(115)	(5,899)	(111)
Adjusted EBITDA attributable to Matador Resources Company shareholders	$72,652	$38,946	$142,611	$56,145

	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands)	2017	2016	2017	2016
Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities:				
Net cash provided by operating activities	$59,933	$31,242	$121,242	$49,600
Net change in operating assets and liabilities	7,198	1,944	9,653	(6,117)
Interest expense, net of non-cash portion	9,204	5,875	17,615	12,773
Adjusted EBITDA attributable to non-controlling interest in subsidiaries	(3,683)	(115)	(5,899)	(111)
Adjusted EBITDA attributable to Matador Resources Company shareholders	$72,652	$38,946	$142,611	$56,145

The net income attributable to Matador Resources Company shareholders increased by $134.4 million to $28.5 million for the three months ended June 30, 2017, as compared to a net loss attributable to Matador Resources Company shareholders of $105.9 million for the three months ended June 30, 2016. This increase in net income attributable to Matador Resources Company shareholders for the three months ended June 30, 2017 as compared to the three months ended June 30, 2016 is primarily attributable to (i) the decrease of $78.2 million in the full-cost ceiling impairment, (ii) the increase in oil and natural gas revenues of $44.4 million and (iii) a change of $39.8 million from unrealized loss to unrealized gain on derivatives, offset by (x) the increase in certain expenses, including a $10.0 million increase in depletion, depreciation and amortization expenses, (y) a $3.1 million increase in interest expense and (z) a $3.7 million increase in stock-based compensation expense.

The net income attributable to Matador Resources Company shareholders increased by $286.0 million to $72.5 million for the six months ended June 30, 2017, as compared to a net loss attributable to Matador Resources Company shareholders of $213.5 million for the six months ended June 30, 2016. This increase in net income attributable to Matador Resources Company shareholders for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016 is primarily attributable to (i) the decrease of $158.6 million in the full-cost ceiling impairment, (ii) the increase in oil and natural gas revenues of $115.3 million and (iii) a change of $67.3 million from unrealized loss to unrealized gain on derivatives, offset by (x) the increase in certain expenses, including a $15.1 million increase in depletion, depreciation and amortization expenses, (y) a $4.3 million increase in interest expense and (z) a $5.6 million increase in stock-based compensation expense.

Our Adjusted EBITDA increased by $33.7 million to $72.7 million for the three months ended June 30, 2017, as compared to $38.9 million for the three months ended June 30, 2016. This increase in our Adjusted EBITDA is primarily

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attributable to higher oil and natural gas production and higher commodity prices, which were partially offset by a decrease in the realized gain on derivatives and an increase in certain expenses for the three months ended June 30, 2017, as compared to the three months ended June 30, 2016.

Our Adjusted EBITDA increased by $86.5 million to $142.6 million for the six months ended June 30, 2017, as compared to $56.1 million for the six months ended June 30, 2016. This increase in our Adjusted EBITDA is primarily attributable to higher oil and natural gas production and higher commodity prices, which were partially offset by a decrease in the realized gain on derivatives and an increase in certain expenses for the six months ended June 30, 2017, as compared to the six months ended June 30, 2016.

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, 2017, 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, gathering, processing, disposal and fractionation commitments and (v) 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, the Company has no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect the Company’s 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, 2017:

	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)]	$821	$—	$—	$821	$—
Senior unsecured notes[(2)]	575,000	—	—	—	575,000
Office leases	23,864	2,494	5,051	5,314	11,005
Non-operated drilling commitments[(3)]	19,697	19,697	—	—	—
Drilling rig contracts[(4)]	41,974	27,295	14,679	—	—
Asset retirement obligations	23,094	703	572	3,737	18,082
Gas processing agreements with non-affiliates[(5)]	11,858	3,795	8,063	—	—
Gathering, processing and disposal agreements with San Mateo[(6)]	256,412	—	36,110	69,994	150,308
Natural gas plant engineering, procurement, construction and installation contract[(7)]	47,026	47,026	—	—	—
Total contractual cash obligations	$999,746	$101,010	$64,475	$79,866	$754,395

(1) At June 30, 2017, we had no borrowings outstanding under our Credit Agreement and approximately $0.8 million in outstanding letters of credit issued pursuant to the Credit Agreement. The Credit Agreement matures in October 2020.

(2) The amounts included in the table above represent principal maturities only.

(3) At June 30, 2017, 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 certain of these wells were in progress at June 30, 2017. If all of these wells are drilled and completed, we will have minimum outstanding aggregate commitments for our participation in these wells of approximately $19.7 million at June 30, 2017, which

we expect to incur within the next year.

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

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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 for more information regarding our contractual commitments.

(6) Effective February 1, 2017, we dedicated our current and future leasehold interests in the Rustler Breaks and Wolf asset areas pursuant to 15-year, fixed-fee natural gas, oil and salt water gathering agreements and salt water disposal agreements. In addition, effective February 1, 2017, we dedicated our current and future leasehold interests in the Rustler Breaks asset area pursuant to a 15-year, fixed-fee natural gas processing agreement. See Note 10 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for more information regarding our contractual commitments.

(7) Beginning in May 2017, a subsidiary of San Mateo entered into certain agreements with third parties for the engineering, procurement, construction and installation of an expansion of the Black River Processing Plant, including required compression. See Note 10 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for more information regarding our contractual commitments.

General Outlook and Trends

For the three months ended June 30, 2017, oil prices averaged $48.15 per Bbl, ranging from a high of $53.40 per Bbl in mid-April to a low of $42.53 per Bbl in late June, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. We realized an average oil price of $46.01 per Bbl ($46.34 per Bbl including realized gains from oil derivatives) for our oil production for the three months ended June 30, 2017, as compared to $42.84 per Bbl ($43.29 per Bbl including realized gains from oil derivatives) for the three months ended June 30, 2016. At August 2, 2017, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date had increased from the weighted average price for the second quarter of 2017, settling at $49.59 per Bbl, which was also an increase as compared to $39.51 per Bbl at August 2, 2016.

For the three months ended June 30, 2017, natural gas prices averaged $3.14 per MMBtu, ranging from a high of approximately $3.42 per MMBtu in mid-May to a low of approximately $2.89 per MMBtu in late June, 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 $3.40 per Mcf ($3.39 per Mcf including realized losses from natural gas derivatives) for our natural gas production (including revenues attributable to natural gas liquids) for the three months ended June 30, 2017, as compared to $2.10 per Mcf ($2.34 per Mcf including realized gains from natural gas derivatives) for the three months ended June 30, 2016. At August 2, 2017, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date had decreased from the weighted average price for the second quarter of 2017, settling at $2.81 per MMBtu, which was a small increase as compared to $2.73 per MMBtu at August 2, 2016.

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 if oil and natural gas prices may rise from their current levels, and in fact, oil and natural gas prices may decrease again 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.

Coinciding with the recent improvements in oil and natural gas prices since the latter part of 2016, we have begun to experience price increases from our service providers for some of the products and services we use in our drilling, completion and production operations. If oil and natural gas prices remain at their current levels for a longer period of time or should they increase further, we could experience additional price increases for drilling, completion and production products and services, although we can provide no estimates as to the eventual magnitude of these increases.

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 will 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 certain 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 our 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.

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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, 2016, which are disclosed in Part II, Item 7A of the Annual Report and incorporated herein by reference.

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 typically 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 which 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 period, providing downside price protection.

We record all derivative financial instruments at fair value. The fair value of our derivative financial instruments is determined using purchase and sale information available for similarly traded securities. At June 30, 2017, Comerica Bank, The Bank of Nova Scotia, BMO Harris Financing (Bank of Montreal) and SunTrust Bank (or affiliates thereof) were the counterparties for all of our derivative instruments. We have considered 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, 2017. 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, 2017 to ensure that (i) information required to be disclosed in the reports it 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 our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2017, there were no changes in our internal controls that have materially affected or are reasonably likely to have a material effect on 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, 2017, 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, 2017 to April 30, 2017	2,225	$ 23.71	—	—
May 1, 2017 to May 31, 2017	2,530	22.84	—	—
June 1, 2017 to June 30, 2017	109	21.74	—	—
Total	4,864	$ 23.21	—	—

(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 7, 2017 By:	/s/ Joseph Wm. Foran
	Joseph Wm. Foran
	Chairman and Chief Executive Officer
Date: August 7, 2017 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 (filed herewith).
3.3	Certificate of Amendment to the Amended and Restated Certificate of Formation of Matador Resources Company dated April 2, 2015 (filed herewith).
3.4	Certificate of Amendment to the Amended and Restated Certificate of Formation of Matador Resources Company effective June 2, 2017 (filed herewith).
3.5	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 December 23, 2016).
3.6	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).
10.1	Form of Employment Agreement between Matador Resources Company and each of Billy E. Goodwin and G. Gregg Krug, effective February 19, 2016 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
10.2	Tenth Amendment to Third Amended and Restated Credit Agreement, dated as of April 28, 2017, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on May 4, 2017).
10.3	Form of Restricted Stock Unit Award Agreement for Annual Grants relating to the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan (filed herewith).
10.4	Form of Restricted Stock Unit Award Agreement for Annual Grants with delayed delivery relating to the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan (filed herewith).
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, 2017 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).