Matador Resources Co
Form 10-Q
May 04, 2018
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2018

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 May 2, 2018, there were 109,258,899 shares of the registrant's common stock, par value $0.01 per share, outstanding.

Table of Contents

MATADOR RESOURCES COMPANY
FORM 10-Q
FOR THE QUARTER ENDED MARCH 31, 2018
INDEX

	Page
PART I — FINANCIAL INFORMATION	3
Item 1. Financial Statements - Unaudited	3
Condensed Consolidated Balance Sheets at March 31, 2018 and December 31, 2017	3
Condensed Consolidated Statements of Operations for the Three Months Ended March 31, 2018 and 2017	4
Condensed Consolidated Statement of Changes in Shareholders' Equity for the Three Months Ended March 31, 2018	5
Condensed Consolidated Statements of Cash Flows for the Three Months Ended March 31, 2018 and 2017	6
Notes to Condensed Consolidated Financial Statements	7
Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations	23
Item 3. Quantitative and Qualitative Disclosures About Market Risk	35
Item 4. Controls and Procedures	35
PART II — OTHER INFORMATION	37
Item 1. Legal Proceedings	37
Item 1A. Risk Factors	37
Item 2. Unregistered Sales of Equity Securities and Use of Proceeds	37
Item 6. Exhibits	37
SIGNATURES	38

Table of Contents

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)

	March 31, 2018	December 31, 2017
ASSETS		
Current assets		
Cash	$27,030	$96,505
Restricted cash	25,753	5,977
Accounts receivable		
Oil and natural gas revenues	68,655	65,962
Joint interest billings	62,294	67,225
Other	7,002	8,031
Derivative instruments	480	1,190
Lease and well equipment inventory	8,803	5,993
Prepaid expenses and other assets	6,961	6,287
Total current assets	206,978	257,170
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	3,187,112	3,004,770
Unproved and unevaluated	644,460	637,396
Midstream and other property and equipment	327,338	281,096
Less accumulated depletion, depreciation and amortization	(2,097,176)	(2,041,806)
Net property and equipment	2,061,734	1,881,456
Other assets	6,993	7,064
Total assets	$2,275,705	$2,145,690
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$31,104	$11,757
Accrued liabilities	191,233	174,348
Royalties payable	62,985	61,358
Amounts due to affiliates	3,248	10,302
Derivative instruments	4,891	16,429
Advances from joint interest owners	8,852	2,789
Amounts due to joint ventures	3,373	4,873
Other current liabilities	806	750
Total current liabilities	306,492	282,606
Long-term liabilities		
Senior unsecured notes payable	574,118	574,073
Asset retirement obligations	25,682	25,080
Derivative instruments	412	—
Other long-term liabilities	6,235	6,385
Total long-term liabilities	606,447	605,538
Commitments and contingencies (Note 9)		
Shareholders' equity		
Common stock - $0.01 par value, 160,000,000 shares authorized; 109,346,765 and 108,513,597 shares issued; and 109,261,912 and 108,510,160 shares outstanding,	1,094	1,085

respectively		
Additional paid-in capital	1,684,188	1,666,024
Accumulated deficit	(450,590)	(510,484)
Treasury stock, at cost, 84,853 and 3,437 shares, respectively	(2,446)	(69)
Total Matador Resources Company shareholders' equity	1,232,246	1,156,556
Non-controlling interest in subsidiaries	130,520	100,990
Total shareholders' equity	1,362,766	1,257,546
Total liabilities and shareholders' equity	$2,275,705	$2,145,690

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

Table of Contents

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

	Three Months Ended March 31,	
	2018	2017
Revenues		
Oil and natural gas revenues	$181,954	$114,847
Third-party midstream services revenues	3,068	1,555
Realized loss on derivatives	(4,258)	(2,219)
Unrealized gain on derivatives	10,416	20,631
Total revenues	191,180	134,814
Expenses		
Production taxes, transportation and processing	17,791	11,807
Lease operating	22,148	15,758
Plant and other midstream services operating	4,220	2,341
Depletion, depreciation and amortization	55,369	33,992
Accretion of asset retirement obligations	364	300
General and administrative	17,926	16,338
Total expenses	117,818	80,536
Operating income	73,362	54,278
Other income (expense)		
Net gain on asset sales and inventory impairment	—	7
Interest expense	(8,491)	(8,455)
Other income	53	70
Total other expense	(8,438)	(8,378)
Net income	64,924	45,900
Net income attributable to non-controlling interest in subsidiaries	(5,030)	(1,916)
Net income attributable to Matador Resources Company shareholders	$59,894	$43,984
Earnings per common share		
Basic	$0.55	$0.44
Diluted	$0.55	$0.44
Weighted average common shares outstanding		
Basic	108,913	99,799
Diluted	109,412	100,298

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

Table of Contents

Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY — UNAUDITED
(In thousands)
For the Three Months Ended March 31, 2018

	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, 2018	108,514	$1,085	$1,666,024	$(510,484)	3	$(69)	$1,156,556	$100,990	$1,257,546
Issuance of common stock pursuant to employee stock compensation plan	697	7	(7)	—	—	—	—	—	—
Issuance of common stock pursuant to directors' and advisors' compensation plan	6	1	(1)	—	—	—	—	—	—
Stock-based compensation expense related to equity-based awards including amounts capitalized	—	—	5,390	—	—	—	5,390	—	5,390
Stock options exercised, net of options forfeited in net share settlements	130	1	(1,918)	—	—	—	(1,917)	—	(1,917)
Restricted stock forfeited	—	—	—	—	82	(2,377)	(2,377)	—	(2,377)
Contributions related to formation of Joint Venture (see Note 6)	—	—	14,700	—	—	—	14,700	—	14,700
Contributions from non-controlling interest owners of less-than-wholly-owned subsidiaries	—	—	—	—	—	—	—	29,400	29,400
Distributions to non-controlling interest owners of less-than-wholly-owned subsidiaries	—	—	—	—	—	—	—	(4,900)	(4,900)
Current period net income	—	—	—	59,894	—	—	59,894	5,030	64,924
Balance at March 31, 2018	109,347	$1,094	$1,684,188	$(450,590)	85	$(2,446)	$1,232,246	$130,520	$1,362,766

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

Table of Contents

Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS — UNAUDITED
(In thousands)

	Three Months Ended March 31,	
	2018	2017
Operating activities		
Net income	$64,924	$45,900
Adjustments to reconcile net income to net cash provided by operating activities		
Unrealized gain on derivatives	(10,416)	(20,631)
Depletion, depreciation and amortization	55,369	33,992
Accretion of asset retirement obligations	364	300
Stock-based compensation expense	4,179	4,166
Amortization of debt issuance cost	365	44
Net gain on asset sales and inventory impairment	—	(7)
Changes in operating assets and liabilities		
Accounts receivable	3,268	(16,777)
Lease and well equipment inventory	(3,806)	147
Prepaid expenses	(674)	(2,251)
Other assets	(249)	39
Accounts payable, accrued liabilities and other current liabilities	15,184	8,256
Royalties payable	1,627	6,984
Advances from joint interest owners	6,063	1,255
Other long-term liabilities	(49)	(108)
Net cash provided by operating activities	136,149	61,309
Investing activities		
Oil and natural gas properties capital expenditures	(183,422)	(204,457)
Expenditures for midstream and other property and equipment	(37,332)	(20,867)
Proceeds from sale of assets	—	350
Net cash used in investing activities	(220,754)	(224,974)
Financing activities		
Proceeds from stock options exercised	164	1,981
Contributions related to formation of Joint Venture	14,700	171,500
Contributions from non-controlling interest owners of less-than-wholly-owned subsidiaries	29,400	4,900
Distributions to non-controlling interest owners of less-than-wholly-owned subsidiaries	(4,900)	—
Taxes paid related to net share settlement of stock-based compensation	(4,458)	(1,896)
Purchase of non-controlling interest of less-than-wholly-owned subsidiary	—	(2,653)
Net cash provided by financing activities	34,906	173,832
(Decrease) increase in cash and restricted cash	(49,699)	10,167
Cash and restricted cash at beginning of period	102,482	214,142
Cash and restricted cash at end of period	$52,783	$224,309

Supplemental disclosures of cash flow information (Note 10)

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

Table of Contents

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, oil transportation services, oil, natural gas and salt water gathering services and salt water disposal services to third parties.

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 the Company 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, 2017 (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 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 normal, recurring adjustments that are necessary for a fair presentation of the Company's interim unaudited condensed consolidated financial statements as of March 31, 2018. Amounts as of December 31, 2017 are derived from the Company's audited consolidated financial statements included 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 and midstream operations, stock-based compensation, valuation of derivative instruments and oil and natural gas reserves. The estimates of oil and natural gas reserves quantities and future net cash flows are the basis for the calculations of depletion and impairment of oil and natural gas properties, as well as estimates of asset retirement obligations and certain tax accruals. While the Company believes its estimates are reasonable, changes in facts and assumptions or the discovery of new information may result in revised estimates. Actual results could differ from these estimates.

Change in Accounting Principles

During the first quarter of 2018, the Company adopted Accounting Standards Codification, Revenue from Contracts with Customers (Topic 606) ("ASC 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. The Company adopted the new guidance using the modified retrospective approach. The adoption did not require an adjustment to opening accumulated deficit for any cumulative effect adjustment and does not have a material impact on the Company's

consolidated balance sheets, statements of operations, statement of shareholders' equity or statements of cash flows. Prior to the adoption of ASC 606, the Company recorded oil and natural gas revenues at the time of physical transfer of such products to the purchaser. The Company followed the sales method of accounting for oil and natural gas sales, recognizing revenues based on the Company's actual proceeds from the oil and natural gas sold to purchasers.

The Company enters into contracts with customers to sell its oil and natural gas production. Revenue on these contracts is recognized in accordance with the five-step revenue recognition model prescribed in ASC 606. Specifically, revenue is

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

recognized when the Company's performance obligations under these contracts are satisfied, which generally occurs with the transfer of control of the oil and natural gas to the purchaser. Control is generally considered transferred when the following criteria are met: (i) transfer of physical custody, (ii) transfer of title, (iii) transfer of risk of loss and (iv) relinquishment of any repurchase rights or other similar rights. Given the nature of the products sold, revenue is recognized at a point in time based on the amount of consideration the Company expects to receive in accordance with the price specified in the contract. Consideration under the oil and natural gas marketing contracts is typically received from the purchaser one to two months after production.

The majority of the Company's oil marketing contracts transfer physical custody and title at or near the wellhead, which is generally when control of the oil has been transferred to the purchaser. The majority of the oil produced is sold under contracts using market-based pricing, which price is then adjusted for differentials based upon delivery location and oil quality. To the extent the differentials are incurred after the transfer of control of the oil, the differentials are included in oil sales on the statements of operations as they represent part of the transaction price of the contract. If the differentials, or other related costs, are incurred prior to the transfer of control of the oil, those costs are included in production taxes, transportation and processing expenses on the Company's consolidated statements of operations as they represent payment for services performed outside of the contract with the customer.

The Company's natural gas is sold at the lease location, at the inlet or outlet of a natural gas plant or at an interconnect near a marketing hub following transportation from a processing plant. The majority of the Company's natural gas is sold under fee-based contracts. When the natural gas is sold at the lease, the purchaser gathers the natural gas and transports the natural gas via pipeline to natural gas processing plants where natural gas liquid ("NGL") products are extracted. The NGL products and remaining residue gas are then sold by the purchaser or the Company sells the natural gas to a third party. Under the fee-based contracts, the Company receives NGL and residue gas value, less the fee component, or is invoiced the fee component. To the extent control of the natural gas transfers upstream of the transportation and processing activities, revenue is recognized as the net amount received from the purchaser. To the extent that control transfers downstream of those services, revenue is recognized on a gross basis, and the related costs are included in production taxes, transportation and processing expenses on the Company's consolidated statements of operations.

The Company recognizes midstream services revenues at the time services have been rendered and the price is fixed and determinable. Third-party midstream services revenues are those revenues from midstream operations related to third parties, including working interest owners in our operated wells. All midstream services revenues related to the Company's working interest are eliminated in consolidation. Since the Company has a right to payment from its customers in amounts that correspond directly to the value that the customer receives from the performance completed on each contract, the Company applies the practical expedient in ASC 606 that allows recognition of revenue in the amount for which there is a right to invoice the customer without estimating a transaction price for each contract and allocating that transaction price to the performance obligations within each contract.

The Company determined the impact to its consolidated financial statements as a result of adoption of this standard was a $2.2 million decrease in oil and natural gas revenues and a $2.2 million decrease in production taxes, transportation and processing expenses for the three months ended March 31, 2018, which was not material. As a result of adoption of this standard, the Company is now required to disclose the following information regarding revenues from contracts with customers and revenues from contracts with customers on a disaggregated basis for the three months ended March 31, 2018 (in thousands).

Revenues from contracts with customers	$185,022
Realized loss on derivatives	(4,258)
Unrealized gain on derivatives	10,416
Total revenues	$191,180

Oil revenues	$148,159
Natural gas revenues	33,795
Third-party midstream services revenues	3,068
Total revenues from contracts with customers	$185,022

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical exemption in accordance with ASC 606. The exemption, as described in ASC 606-10-50-14(a), applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

During the first quarter of 2018, the Company adopted Accounting Standards Update ("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. The Company adopted ASU 2016-18 effective January 1, 2018 and determined that the adoption of this ASU changed the presentation of its beginning and ending cash balances and eliminated the presentation of changes in restricted cash balances from investing activities in its consolidated statements of cash flows. The Company adopted the new guidance using the retrospective transition method; as a result, approximately $6.0 million and $1.3 million of restricted cash was added to the beginning cash balance for the three months ended March 31, 2018 and 2017, respectively.

During the first quarter of 2018, the Company adopted 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. The Company adopted ASU 2017-01 prospectively, which did not have a material impact on its consolidated financial statements.

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 both the three months ended March 31, 2018 and 2017, the cost center ceiling was higher than the capitalized costs of oil and natural gas properties, and, as a result, no impairment charge was necessary.

The Company capitalized approximately $7.3 million and $5.6 million of its general and administrative costs for the three months ended March 31, 2018 and 2017, respectively, and approximately $1.9 million and $1.2 million of its interest expense for the three months ended March 31, 2018 and 2017, respectively.

Earnings (Loss) Per Common Share

The Company reports basic earnings attributable to Matador Resources Company shareholders per common share, which excludes the effect of potentially dilutive securities, and diluted earnings 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 months ended March 31, 2018 and 2017 (in thousands).

	Three Months Ended March 31,	
	2018	2017
Weighted average common shares outstanding		
Basic	108,913	99,799
Dilutive effect of options and restricted stock units	499	499
Diluted weighted average common shares outstanding	109,412	100,298

9

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

Recent Accounting Pronouncements
Leases. In February 2016, the Financial Accounting Standards Board ("FASB") issued ASU 2016-02, Leases (Topic 842), which requires the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous U.S. GAAP. This ASU will become effective for fiscal years beginning after December 15, 2018 with early adoption permitted. Entities are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. These practical expedients relate to the identification and classification of leases that commenced before the effective date, initial direct costs for leases that commenced before the effective date and the ability to use hindsight in evaluating lessee options to extend or terminate a lease or to purchase the underlying asset. In January 2018, the FASB issued ASU 2018-01, Leases (Topic 842), which is a land easement practical expedient. If the Company elects to use this practical expedient, the Company should evaluate new or modified land easements under this ASU beginning at the date of adoption. Adoption of ASU 2016-02 will result in increased reported assets and liabilities. The quantitative impact of the new lease standard will depend on the leases in force at the time of adoption. The Company is currently evaluating the impact of the adoption of these ASUs on its consolidated financial statements, including identifying all leases, as defined under the new lease standard, determining which practical expedients the Company will use and quantifying the impact of the new lease standard on existing leases. The Company expects to adopt these ASUs on January 1, 2019.

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 3 — ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company's asset retirement obligations for the three months ended March 31, 2018 (in thousands).

Beginning asset retirement obligations	$26,256
Liabilities incurred during period	747
Liabilities settled during period	(411)
Accretion expense	364
Ending asset retirement obligations	26,956
Less: current asset retirement obligations[(1)]	(1,274)
Long-term asset retirement obligations	$25,682

(1) Included in accrued liabilities in the Company's interim unaudited condensed consolidated balance sheet at March 31, 2018.

NOTE 4 — DEBT

At March 31, 2018, 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 $2.1 million in outstanding letters of credit issued pursuant to the Credit Agreement. At May 2, 2018, the Company had $575.0 million of outstanding 6.875% senior notes due 2023, $45.0 million in borrowings outstanding under the Credit Agreement and approximately $3.0 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 2018, the lenders completed their review of the Company's proved oil and natural gas reserves at December 31, 2017, and as a result, on March 5, 2018, the borrowing base was increased to $725.0 million. This March 2018 redetermination constituted the regularly scheduled May 1 redetermination. The Company elected to keep the borrowing commitment at $400.0 million and the maximum facility amount remained at $500.0 million. Borrowings under the Credit Agreement are limited to the lowest of the borrowing base, the maximum facility amount and the elected commitment. The Credit Agreement matures on October 16, 2020.

The Company believes that it was in compliance with the terms of the Credit Agreement at March 31, 2018.

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 15 and October 15 of each year.

NOTE 5 — INCOME TAXES

The Company's deferred tax assets exceeded its deferred tax liabilities at March 31, 2018 due to the deferred tax assets generated by full-cost ceiling impairment charges recorded in prior periods. The Company established a valuation allowance against most of the deferred tax assets beginning in the third quarter of 2015 and retained a full valuation allowance at March 31, 2018 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 is more likely than not to be utilized.

11

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 6 — EQUITY

Stock-based Compensation
In February 2018, the Company granted awards of 667,488 shares of restricted stock and options to purchase 563,408 shares of the Company's common stock at an exercise price of $29.68 per share to certain of its employees. The fair value of these awards was approximately $26.9 million. All of these awards vest ratably over three years.

Performance Incentive
In connection with the formation of San Mateo in 2017, the Company has the ability to earn a total of $73.5 million in performance incentives to be paid by its joint venture partner, a subsidiary of Five Point Energy LLC ("Five Point"), over a five-year period. The Company earned, and Five Point paid to the Company, $14.7 million in performance incentives in the first quarter of 2018, and the Company may earn an additional $58.8 million in performance incentives over the next four years. These performance incentives are recorded as an increase to additional paid-in capital when received.

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 7 — DERIVATIVE FINANCIAL INSTRUMENTS

At March 31, 2018, the Company had various costless collar, three-way costless collar and swap 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 and fixed price for the swaps. Each contract is set to expire at varying times during 2018.

The following is a summary of the Company's open costless collar contracts for oil and natural gas at March 31, 2018.

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 - WTI [1]	04/01/2018 - 12/31/2018	2,160,000	$ 44.27	$ 60.29	$ (11,663)
Oil - WTI [1]	01/01/2019 - 12/31/2019	2,400,000	$ 50.00	$ 64.75	(1,288)
Oil - LLS [2]	04/01/2018 - 12/31/2018	540,000	$ 45.00	$ 63.05	(2,708)
Natural Gas	04/01/2018 - 12/31/2018	12,600,000	$ 2.58	$ 3.67	480
Total open costless collar contracts					$ (15,179)

(1) NYMEX West Texas Intermediate crude oil.
(2) Argus Louisiana Light Sweet crude oil.

The following is a summary of the Company's open three-way costless collar contracts for oil at March 31, 2018. Open three-way costless collars consist of a long put (the floor), a short call (the ceiling) and a long call that limits losses on the upside.

Commodity	Calculation Period	Notional Quantity (Bbl)	Weighted Average Price Floor ($/Bbl)	Weighted Average Price, Short Call ($/Bbl)	Weighted Average Price, Long Call ($/Bbl)	Fair Value of Asset (Liability) (thousands)
Oil - WTI [1]	04/01/2018 - 12/31/2018	1,440,000	$ 50.08	$ 63.50	$ 66.68	$ (1,196)
Total open three-way costless collar contracts						$ (1,196)

(1) NYMEX West Texas Intermediate crude oil.

The following is a summary of the Company's open basis swap contracts for oil at March 31, 2018.

Commodity	Calculation Period	Notional Quantity (Bbl)	Fixed Price ($/Bbl)	Fair Value of Asset (Liability) (thousands)
Oil Basis Swaps	04/01/2018 - 12/31/2018	3,915,000	$(1.02)	$ 11,552
Total open swap contracts				$ 11,552
Total open derivative financial instruments				$ (4,823)

From time-to-time, we enter into derivative financial instruments with certain counterparties. These derivative financial instruments are subject to master netting arrangements, and 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.

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 7 — DERIVATIVE FINANCIAL INSTRUMENTS — Continued

The following table presents the gross asset and liability fair values of the Company's commodity price derivative financial instruments and the location of these balances in the interim unaudited condensed consolidated balance sheets as of March 31, 2018 and December 31, 2017 (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
March 31, 2018			
Current assets	$109,635	$ (109,155)	$ 480
Other assets	5,835	(5,835)	—
Current liabilities	(114,046)	109,155	(4,891)
Other liabilities	(6,247)	5,835	(412)
Total	$(4,823)	$ —	$ (4,823)
December 31, 2017			
Current assets	$131,092	$ (129,902)	$ 1,190
Current liabilities	(146,331)	129,902	(16,429)
Total	$(15,239)	$ —	$ (15,239)

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 March 31,	
Type of Instrument	Location in Condensed Consolidated Statement of Operations	2018	2017
Derivative Instrument			
Oil	Revenues: Realized loss on derivatives	$(4,309)	$(1,635)
Natural Gas	Revenues: Realized gain (loss) on derivatives	51	(584)
Realized loss on derivatives		(4,258)	(2,219)
Oil	Revenues: Unrealized gain on derivatives	11,127	17,780
Natural Gas	Revenues: Unrealized (loss) gain on derivatives	(711)	2,851
Unrealized gain on derivatives		10,416	20,631
Total		$6,158	$18,412

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 8 — 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 March 31, 2018 and December 31, 2017 (in thousands).

	Fair Value Measurements at March 31, 2018 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Natural gas derivatives	$—	$480	$—	$480
Oil derivatives and basis swaps	—	(5,303)	—	(5,303)
Total	$—	$(4,823)	$—	$(4,823)

	Fair Value Measurements at December 31, 2017 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Natural gas derivatives	$—	$1,190	$—	$1,190
Oil derivatives and basis swaps	—	(16,429)	—	(16,429)
Total	$—	$(15,239)	$—	$(15,239)

Additional disclosures related to derivative financial instruments are provided in Note 7.

Other Fair Value Measurements

At March 31, 2018 and December 31, 2017, 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 March 31, 2018 and December 31, 2017, the fair value of the Notes was $599.3 million and $614.1 million, respectively, based on quoted market prices, which represent Level 1 inputs in the fair value hierarchy.

15

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 9 — COMMITMENTS AND CONTINGENCIES

Processing, Transportation and Salt Water Disposal Commitments

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 March 31, 2018, the total deficiency fee required to be paid would be approximately $12.6 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 contract year can be carried over to the next contract year for purposes of calculating the natural gas deficiency. The Company paid approximately $3.5 million and $3.2 million in natural gas processing and gathering fees under this agreement during the three months ended March 31, 2018 and 2017, 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 — Eddy County, New Mexico Natural Gas Transportation

In late 2017, the Company entered into an 18-year, fixed-fee natural gas transportation agreement whereby the Company committed to deliver a portion of the residue natural gas production at the tailgate of San Mateo's Black River cryogenic natural gas processing plant in the Rustler Breaks asset area (the "Black River Processing Plant") to transport through the counterparty's pipeline. Under this agreement, if the Company does not meet the volume commitment for transportation in a contract year, the Company will owe the fees to transport the committed volume whether or not the committed volume is utilized. The minimum contractual obligation at March 31, 2018 was approximately $58.8 million. The Company paid approximately $0.5 million in transportation fees under this agreement during the three months ended March 31, 2018.

In late 2017, the Company also entered into a fixed-fee NGL transportation and fractionation agreement whereby the Company committed to deliver its NGL production at the tailgate of the Black River Processing Plant. The Company is committed to deliver a minimum amount of NGLs to the counterparty upon construction and completion of a pipeline expansion and a fractionation facility by the counterparty, which is currently expected to be completed late in 2019. The Company has no rights to compel the counterparty to construct this pipeline extension or fractionation facility. If the counterparty does not construct the pipeline extension and fractionation facility, then the Company does not have any minimum volume commitments under the agreement. If the counterparty constructs the pipeline extension and fractionation facility on or prior to February 28, 2021, then the Company will have a commitment to deliver a minimum amount of NGLs for seven years following the completion of the pipeline extension and fractionation facility. If the Company does not meet its NGL volume commitment in any quarter during the seven-year commitment period, it will be required to pay a deficiency fee per gallon of NGL deficiency. Should the pipeline extension and fractionation facility be completed on or prior to February 28, 2021, the minimum contractual obligation during the seven-year period would be approximately $132.5 million.

Delaware Basin — San Mateo

In February 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"). San Mateo provides 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 March 31, 2018 was approximately $225.6 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. The expansion was completed late in the first quarter of 2018. San Mateo's total commitments under these agreements are $55.3 million. The subsidiary of

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 9 — COMMITMENTS AND CONTINGENCIES — Continued

San Mateo paid approximately $2.4 million under these agreements during the three months ended March 31, 2018. As of March 31, 2018, the remaining obligations under these agreements were $3.1 million, which are expected to be paid within the next few months.

During the first quarter of 2018, a subsidiary of San Mateo entered into agreements for additional field compression and an amine gas treatment unit to maximize the operation of the Black River Processing Plant. San Mateo's total commitments under these agreements are $13.4 million. The subsidiary of San Mateo paid approximately $0.4 million under these agreements during the three months ended March 31, 2018. As of March 31, 2018, the remaining obligations under these agreements were $13.0 million, which are expected to be paid 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. 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 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 $32.7 million at March 31, 2018.

At March 31, 2018, 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 $30.1 million at March 31, 2018. 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.

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 10 — SUPPLEMENTAL DISCLOSURES

Accrued Liabilities

The following table summarizes the Company's current accrued liabilities at March 31, 2018 and December 31, 2017 (in thousands).

	March 31, 2018	December 31, 2017
Accrued evaluated and unproved and unevaluated property costs	$108,200	$105,347
Accrued midstream property costs	22,817	14,823
Accrued lease operating expenses	12,234	12,611
Accrued interest on debt	18,228	8,345
Accrued asset retirement obligations	1,274	1,176
Accrued partners' share of joint interest charges	26,109	27,628
Other	2,371	4,418
Total accrued liabilities	$191,233	$174,348

Supplemental Cash Flow Information

The following table provides supplemental disclosures of cash flow information for the three months ended March 31, 2018 and 2017 (in thousands).

	Three Months Ended March 31,	
	2018	2017
Increase in asset retirement obligations related to mineral properties	$337	$1,434
Decrease in asset retirement obligations related to midstream properties	$—	$(194)
Increase in liabilities for oil and natural gas properties capital expenditures	$5,863	$2,820
Increase (decrease) in liabilities for midstream properties capital expenditures	$8,090	$(6,329)
Stock-based compensation expense recognized as liability	$(102)	$(152)
Decrease in liabilities for accrued cost to issue equity	$—	$(294)
Transfer of inventory (to) from oil and natural gas properties	$(176)	$31
Transfer of inventory to midstream and other property and equipment	$(820)	$—

The following table provides a reconciliation of cash and restricted cash recorded in the interim unaudited condensed consolidated balance sheets to cash and restricted cash as presented on the interim unaudited condensed consolidated statements of cash flows (in thousands).

	Three Months Ended March 31,	
	2018	2017
Cash	$27,030	$209,705
Restricted cash	25,753	14,604
Total cash and restricted cash	$52,783	$224,309

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 11 — 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, oil transportation services, natural gas, oil and salt water gathering services and salt water disposal services to third parties. 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.
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 March 31, 2018					
Oil and natural gas revenues	$180,260	$1,694	$—	$ —	$181,954
Midstream services revenues	—	15,812	—	(12,744)	3,068
Realized loss on derivatives	(4,258)	—	—	—	(4,258)
Unrealized gain on derivatives	10,416	—	—	—	10,416
Expenses[1]	106,155	7,198	17,209	(12,744)	117,818
Operating income (loss)[2]	$80,263	$10,308	$(17,209)	$ —	$73,362
Total assets	$1,902,151	$323,536	$50,018	$ —	$2,275,705
Capital expenditures[3]	$189,445	$45,717	$526	$ —	$235,688

(1) Includes depletion, depreciation and amortization expenses of $53.2 million and $1.5 million for the exploration and production and midstream segments, respectively. Also includes corporate depletion, depreciation and amortization expenses of $0.6 million.

(2) Includes $5.0 million in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

(3) Includes $22.4 million in capital expenditures attributable to non-controlling interest in subsidiaries related to the midstream segment.

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 11 — SEGMENT INFORMATION — Continued

	Exploration and Production	Midstream	Corporate	Consolidations and Eliminations	Consolidated Company
Three Months Ended March 31, 2017					
Oil and natural gas revenues	$114,165	$682	$—	$ —	$114,847
Midstream services revenues	—	9,616	—	(8,061)	1,555
Realized loss on derivatives	(2,219)	—	—	—	(2,219)
Unrealized gain on derivatives	20,631	—	—	—	20,631
Expenses[1]	68,339	4,503	15,755	(8,061)	80,536
Operating income (loss)[2]	$64,238	$5,795	$(15,755)	$ —	$54,278
Total assets	$1,296,823	$166,148	$223,422	$ —	$1,686,393
Capital expenditures[3]	$208,373	$12,880	$1,464	$ —	$222,717

(1) Includes depletion, depreciation and amortization expenses of $32.5 million and $1.2 million for the exploration and production and midstream segments, respectively. Also includes corporate depletion, depreciation and amortization expenses of $0.3 million.

(2) Includes $1.9 million in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

(3) Includes $4.7 million in capital expenditures attributable to non-controlling interest in subsidiaries related to the midstream segment.

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 12 — SUBSIDIARY GUARANTORS

Matador's Notes are jointly and severally guaranteed by certain subsidiaries of Matador (the "Guarantor Subsidiaries") on a full and unconditional basis (except for customary release provisions). At March 31, 2018, the Guarantor Subsidiaries were 100% owned by Matador. Matador is a parent holding company and has no independent assets or operations, and there are no significant restrictions on the ability of Matador to obtain funds from the Guarantor Subsidiaries by dividend or loan. San Mateo and its subsidiaries (the "Non-Guarantor Subsidiaries") are not guarantors of the Notes.

The following presents condensed consolidating financial information of the issuer (Matador), the Non-Guarantor Subsidiaries, the Guarantor Subsidiaries and all entities on a 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
March 31, 2018

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
ASSETS					
Intercompany receivable	$601,346	$ 487	$—	$(601,833)	$—
Third-party current assets	292	30,637	176,049	—	206,978
Net property and equipment	—	267,651	1,794,083	—	2,061,734
Investment in subsidiaries	1,216,908	—	136,713	(1,353,621)	—
Third-party long-term assets	6,444	—	3,504	(2,955)	6,993
Total assets	$1,824,990	$ 298,775	$2,110,349	$(1,958,409)	$2,275,705
LIABILITIES AND EQUITY					
Intercompany payable	$—	$ —	$601,833	$(601,833)	$—
Third-party current liabilities	18,626	28,113	260,027	(274)	306,492
Senior unsecured notes payable	574,118	—	—	—	574,118
Other third-party long-term liabilities	—	3,429	31,581	(2,681)	32,329
Total equity attributable to Matador Resources Company	1,232,246	136,713	1,216,908	(1,353,621)	1,232,246
Non-controlling interest in subsidiaries	—	130,520	—	—	130,520
Total liabilities and equity	$1,824,990	$ 298,775	$2,110,349	$(1,958,409)	$2,275,705

Condensed Consolidating Balance Sheet
December 31, 2017

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
ASSETS					
Intercompany receivable	$585,109	$ 2,912	$—	$(588,021)	$—
Third-party current assets	2,240	9,334	245,596	—	257,170
Net property and equipment	—	223,178	1,658,278	—	1,881,456
Investment in subsidiaries	1,147,295	—	111,077	(1,258,372)	—
Third-party long-term assets	6,425	—	3,642	(3,003)	7,064
Total assets	$1,741,069	$ 235,424	$2,018,593	$(1,849,396)	$2,145,690
LIABILITIES AND EQUITY					
Intercompany payable	$—	$ —	$588,021	$(588,021)	$—

Third-party current liabilities	8,847	19,891	254,142	(274)	282,606
Senior unsecured notes payable	574,073	—	—	—	574,073
Other third-party long-term liabilities	1,593	3,466	29,135	(2,729)	31,465
Total equity attributable to Matador Resources Company	1,156,556	111,077	1,147,295	(1,258,372)	1,156,556
Non-controlling interest in subsidiaries	—	100,990	—	—	100,990
Total liabilities and equity	$1,741,069	$ 235,424	$2,018,593	$(1,849,396)	$2,145,690

Condensed Consolidating Statement of Operations
For the Three Months Ended March 31, 2018

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Total revenues	$—	$ 17,194	$ 186,480	$(12,494)	$ 191,180
Total expenses	1,234	6,928	122,150	(12,494)	117,818
Operating (loss) income	(1,234)	10,266	64,330	—	73,362
Interest expense	(8,491)	—	—	—	(8,491)
Other income	6	—	47	—	53
Earnings in subsidiaries	69,613	—	5,236	(74,849)	—
Income before income taxes	59,894	10,266	69,613	(74,849)	64,924
Net income attributable to non-controlling interest in subsidiaries	—	(5,030)	—	—	(5,030)
Net income attributable to Matador Resources Company shareholders	$59,894	$ 5,236	$ 69,613	$(74,849)	$ 59,894

Condensed Consolidating Statement of Operations
For the Three Months Ended March 31, 2017

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Total revenues	$—	$ 9,663	$ 132,648	$(7,497)	$ 134,814
Total expenses	1,260	3,868	82,905	(7,497)	80,536
Operating (loss) income	(1,260)	5,795	49,743	—	54,278
Net gain on asset sales and inventory impairment	—	—	7	—	7
Interest expense	(8,455)	—	—	—	(8,455)
Other income	27	—	43	—	70
Earnings in subsidiaries	53,672	—	3,825	(57,497)	—
Income before income taxes	43,984	5,795	53,618	(57,497)	45,900
Total income tax provision (benefit)	—	54	(54)	—	—
Net income attributable to non-controlling interest in subsidiaries	—	(1,916)	—	—	(1,916)
Net income attributable to Matador Resources Company shareholders	$43,984	$ 3,825	$ 53,672	$(57,497)	$ 43,984

Condensed Consolidating Statement of Cash Flows
For the Three Months Ended March 31, 2018

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Net cash (used in) provided by operating activities	$(144)	$ 10,385	$ 125,908	$ —	$ 136,149
Net cash used in investing activities	—	(36,831)	(204,323)	20,400	(220,754)
Net cash provided by financing activities	—	44,900	10,406	(20,400)	34,906
(Decrease) increase in cash and restricted cash	(144)	18,454	(68,009)	—	(49,699)
Cash and restricted cash at beginning of period	286	5,663	96,533	—	102,482
Cash and restricted cash at end of period	$ 142	$ 24,117	$ 28,524	$ —	$ 52,783

Condensed Consolidating Statement of Cash Flows
For the Three Months Ended March 31, 2017

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Net cash (used in) provided by operating activities	$(99,235)	$ (1,064)	$ 161,608	$ —	$ 61,309
Net cash provided by (used in) investing activities	29	(19,147)	(63,816)	(142,040)	(224,974)
Net cash provided by financing activities	—	31,707	85	142,040	173,832
(Decrease) increase in cash and restricted cash	(99,206)	11,496	97,877	—	10,167
Cash and restricted cash at beginning of period	99,795	2,900	111,447	—	214,142
Cash and restricted cash at end of period	$589	$ 14,396	$ 209,324	$ —	$ 224,309

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED
NOTE 13 — SUBSEQUENT EVENTS

In April 2018, the Company entered into a short-term natural gas transportation agreement whereby the Company committed to firm transportation from the tailgate of the Black River Processing Plant. Under this short-term agreement, the Company will owe the fees to transport the committed volume whether or not the committed volume is transported through the counterparty's pipeline. The minimum contractual obligation under this short-term contract is approximately $4.8 million. This short-term agreement ends September 30, 2019.
In addition, in April 2018, the Company entered into a 16-year, fixed-fee natural gas transportation agreement that begins on October 1, 2019, whereby the Company committed to firm transportation from the tailgate of the Black River Processing Plant. The Company will owe the fees to transport the committed volume whether or not the committed volume is transported through the counterparty's pipeline. The minimum contractual obligation is approximately $56.8 million.

Table of Contents

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 consolidated financial statements and related notes thereto contained herein and the consolidated financial statements and related notes thereto contained in our Annual Report on Form 10-K for the year ended December 31, 2017 (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 (unless the context indicates otherwise) 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," "would" or other si although 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 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;

Table of Contents

- our ability and the ability of our midstream joint venture to construct and operate midstream facilities, including the expansion and operation 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 undertake no obligation to update forward-looking statements to reflect actual results or changes in factors or assumptions affecting such forward-looking statements, except as required by law, including the securities laws of the United States and the rules and regulations of the SEC.

Overview

We are an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. Our current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. We also operate in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. Additionally, we conduct midstream operations, primarily through our midstream joint venture, San Mateo Midstream, LLC (“San Mateo”), in support of our exploration, development and production operations and provide natural gas processing, oil transportation services, oil, natural gas and salt water gathering services and salt water disposal services to third parties.

First Quarter Highlights

For the three months ended March 31, 2018, our total oil equivalent production was 4.1 million BOE, and our average daily oil equivalent production was 45,273 BOE per day, of which 26,465 Bbl per day, or 58%, was oil and 112.9 MMcf per day, or 42%, was natural gas. Our oil production of 2.4 million Bbl for the three months ended March 31, 2018 increased 44% year-over-year from 1.6 million Bbl for the three months ended March 31, 2017. Our natural gas production of 10.2 Bcf for the three months ended March 31, 2018 increased 28% year-over-year from 7.9 Bcf for the three months ended March 31, 2017.

For the first quarter of 2018, we reported net income attributable to Matador Resources Company shareholders of approximately $59.9 million, or $0.55 per diluted common share on a GAAP basis, as compared to net income attributable to Matador Resources Company shareholders of $44.0 million, or $0.44 per diluted common share, for the first quarter of 2017. For the first quarter of 2018, our Adjusted EBITDA attributable to Matador Resources Company

shareholders ("Adjusted EBITDA"), a non-GAAP financial measure, was $117.3 million, as compared to Adjusted EBITDA of $70.0 million during the first quarter of 2017. 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 first quarter of 2018, see "— Results of Operations" below.

During the first quarter of 2018, 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 2018 operating six drilling rigs in the Delaware Basin and continued to do so throughout the first quarter of 2018. We expect to operate those six rigs in the

Table of Contents

Delaware Basin throughout 2018, including three rigs in the Rustler Breaks asset area, one rig in the Wolf/Jackson Trust asset areas, one rig in the Ranger/Arrowhead and Twin Lakes asset areas and one rig in the Antelope Ridge asset area. San Mateo's third commercial salt water disposal well in the Rustler Breaks asset area became operational in the first quarter of 2018, and one of the three rigs operating in the Rustler Breaks asset area is also expected to drill at least two additional commercial salt water disposal wells in that area during 2018 for San Mateo, which, when completed, will result in five commercial salt water disposal wells in the Rustler Breaks asset area. Depending on commodity prices, costs, opportunities in new asset areas like Antelope Ridge, liquidity and other factors, we may consider adding a seventh rig towards the end of 2018.

In late March 2018, we completed the expansion of San Mateo's Black River cryogenic natural gas processing plant in the Rustler Breaks asset area in Eddy County, New Mexico (the "Black River Processing Plant"), adding an incremental designed inlet capacity of 200 MMcf of natural gas per day and bringing the total designed inlet capacity of the Black River Processing Plant to 260 MMcf of natural gas per day. The expanded Black River Processing Plant supports our exploration and development activities in the Delaware Basin, and with the expanded capacity, San Mateo can offer natural gas processing services to other producers as well.

During the first quarter of 2018, we did not conduct any operated drilling and completion activities on our leasehold properties in the Eagle Ford shale play in South Texas or in the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas, although we did participate in the drilling and completion of 3 gross (0.1 net) non-operated Haynesville shale wells that were turned to sales in the first quarter of 2018. We have no operated drilling activities planned in the Eagle Ford or in the Haynesville shale and Cotton Valley plays for the remainder of 2018.

We completed and turned to sales a total of 29 gross (16.1 net) wells in the Delaware Basin during the first quarter of 2018, including 16 gross (13.4 net) operated horizontal wells, one gross (1.0 net) operated vertical well and 12 gross (1.7 net) non-operated horizontal wells. During the first quarter of 2018, we began producing oil and natural gas from our first three gross (3.0 net) operated wells in the Antelope Ridge asset area, including a Wolfcamp A-XY completion, a Wolfcamp A-Lower completion and a First Bone Spring completion. We also participated in two gross (0.1 net) non-operated wells in the Antelope Ridge asset area. In the Rustler Breaks asset area, we began producing oil and natural gas from a total of 16 gross (9.1 net) wells during the first quarter of 2018, including nine gross (7.8 net) operated and seven gross (1.3 net) non-operated wells. Of the nine gross operated wells in the Rustler Breaks asset area, four were Wolfcamp A-XY completions, two were Wolfcamp A-Lower completions, two were Wolfcamp B-Blair completions and one was a vertical Morrow completion. In addition, we began producing oil and natural gas from two gross (1.0 net) operated wells in the Wolf and Jackson Trust asset areas during the first quarter of 2018, including a Wolfcamp A-XY completion and a Wolfcamp A-Lower completion. In the Ranger/Arrowhead and Twin Lakes asset areas, we began producing oil and natural gas from six gross (2.9 net) wells, including three gross (2.6 net) operated wells and three gross (0.3 net) non-operated wells during the first quarter of 2018.

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 first quarter of 2018 was 37,160 BOE per day, consisting of 23,363 Bbl of oil per day and 82.8 MMcf of natural gas per day, a 51% increase from production of 24,535 BOE per day, consisting of 15,685 Bbl of oil per day and 53.1 MMcf of natural gas per day, in the first quarter of 2017. The Delaware Basin contributed approximately 88% of our daily oil production and approximately 73% of our daily natural gas production in the first quarter of 2018, as compared to approximately 86% of our daily oil production and approximately 60% of our daily natural gas production in the first quarter of 2017.

Strategic Relationship with Plains

On January 22, 2018, a subsidiary of San Mateo entered into a strategic relationship with a subsidiary of Plains All American Pipeline, L.P. ("Plains") to gather and transport crude oil for us and additional customers in and around the Rustler Breaks asset area. Subsidiaries of San Mateo and Plains have agreed to work together through a joint tariff arrangement and related transactions to offer producers located within a joint development area of approximately 400,000 acres in Eddy County, New Mexico crude oil transportation services from the wellhead to Midland, Texas with access to other end markets, such as Cushing and the Gulf Coast. In addition, another subsidiary of Plains has

agreed to purchase our oil production in the Rustler Breaks asset area in Eddy County, New Mexico and the Wolf asset area in Loving County, Texas.

Critical Accounting Policies

Other than as discussed in Note 2 to the interim unaudited condensed consolidated financial statements in this Quarterly Report related to the adoption of ASU 2014-09, Revenue from Contracts with Customers (Topic 606), 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.

Table of Contents

Results of Operations

Revenues

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

	Three Months Ended March 31,	
	2018	2017
Operating Data:		
Revenues (in thousands):[1]		
Oil	$148,159	$83,636
Natural gas	33,795	31,211
Total oil and natural gas revenues	181,954	114,847
Third-party midstream services revenues	3,068	1,555
Realized loss on derivatives	(4,258)	(2,219)
Unrealized gain on derivatives	10,416	20,631
Total revenues	$191,180	$134,814
Net Production Volumes:[1]		
Oil (MBbl)[2]	2,382	1,649
Natural gas (Bcf)[3]	10.2	7.9
Total oil equivalent (MBOE)[4]	4,075	2,970
Average daily production (BOE/d)[5]	45,273	32,999
Average Sales Prices:		
Oil, without realized derivatives (per Bbl)	$62.20	$50.72
Oil, with realized derivatives (per Bbl)	$60.40	$49.73
Natural gas, without realized derivatives (per Mcf)	$3.33	$3.94
Natural gas, with realized derivatives (per Mcf)	$3.33	$3.86

(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) One thousand barrels of oil.

(3) One billion cubic feet of natural gas.

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

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

Three Months Ended March 31, 2018 as Compared to Three Months Ended March 31, 2017

Oil and natural gas revenues. Our oil and natural gas revenues increased $67.1 million to $182.0 million, or 58%, for the three months ended March 31, 2018, as compared to $114.8 million for the three months ended March 31, 2017. Our oil revenues increased $64.5 million, or 77%, to $148.2 million for the three months ended March 31, 2018, as compared to $83.6 million for the three months ended March 31, 2017. The increase in oil revenues resulted from (i) a higher weighted average oil price realized for the three months ended March 31, 2018 of $62.20 per Bbl, as compared to $50.72 per Bbl realized for the three months ended March 31, 2017, and (ii) the 44% increase in our oil production to 2.4 million Bbl of oil for the three months ended March 31, 2018, or 26,465 Bbl of oil per day, as compared to 1.6 million Bbl of oil, or 18,323 Bbl of oil per day, for the three months ended March 31, 2017. The increase in oil production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin. Our natural gas revenues increased by $2.6 million, or 8%, to $33.8 million for the three months ended March 31, 2018, as compared to $31.2 million for the three months ended March 31, 2017. The increase in natural gas revenues resulted from the 28% increase in our natural gas production to 10.2 Bcf for the three months ended March 31, 2018, as compared to 7.9 Bcf for the three months ended March 31, 2017, which was partially offset by a lower weighted average natural gas price realized for the three months ended March 31, 2018 of $3.33 per Mcf, as compared to $3.94 per Mcf realized for the three months ended March 31, 2017. The increase in natural gas production was

primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin.

Table of Contents

Third-party midstream services revenues. Our third-party midstream services revenues increased $1.5 million to $3.1 million, or 97%, for the three months ended March 31, 2018, as compared to $1.6 million for the three months ended March 31, 2017. Third-party midstream services revenues are those revenues from midstream operations related to third parties, including working interest owners in our operated wells. This increase was primarily attributable to a significant increase in (i) natural gas gathering and processing revenues to approximately $1.9 million for the three months ended March 31, 2018, as compared to $1.1 million for the three months ended March 31, 2017, due to increased natural gas production in our Rustler Breaks and Wolf asset areas and (ii) an increase in our third-party salt water gathering and disposal revenue to approximately $1.1 million for the three months ended March 31, 2018, as compared to approximately $0.3 million for the three months ended March 31, 2017.

Realized loss on derivatives. Our realized net loss on derivatives was $4.3 million for the three months ended March 31, 2018, as compared to a realized net loss of $2.2 million for the three months ended March 31, 2017. We realized a net loss of $4.3 million from our oil derivative contracts for the three months ended March 31, 2018 resulting from oil prices above the short call/ceiling prices of certain of our oil costless collar contracts and oil basis prices below swap prices of certain of our oil basis swap contracts. We realized a net loss of $1.6 million and $0.6 million from our oil and natural gas derivative contracts, respectively, for the three months ended March 31, 2017 resulting from oil and natural gas prices that were above the ceiling prices of the majority of our oil and natural gas costless collar contracts. We realized an average loss on our oil derivatives of approximately $1.81 per Bbl produced during the three months ended March 31, 2018, as compared to an average loss of $0.99 per Bbl produced during the three months ended March 31, 2017. Our total oil volumes hedged for the three months ended March 31, 2018 represented 55% of our total oil production, as compared to 58% of our total oil production for the three months ended March 31, 2017. We realized an average loss on our natural gas derivatives of less than $0.01 per Mcf produced during the three months ended March 31, 2018, as compared to an average loss of approximately $0.08 per Mcf produced for the three months ended March 31, 2017. Our total natural gas volumes hedged for the three months ended March 31, 2018 represented 41% of our total natural gas production, as compared to 66% of our total natural gas production for the three months ended March 31, 2017.

Unrealized gain on derivatives. Our unrealized net gain on derivatives was $10.4 million for the three months ended March 31, 2018, as compared to an unrealized net gain of $20.6 million for the three months ended March 31, 2017. During the three months ended March 31, 2018, the net fair value of our open oil and natural gas derivative contracts changed to a net liability of approximately $4.8 million from a net liability of $15.2 million at December 31, 2017, resulting in an unrealized net gain on derivatives of $10.4 million for the three months ended March 31, 2018. During the three months ended March 31, 2017, the net fair value of our open oil and natural gas derivative contracts changed to a net liability of approximately $4.3 million from a net liability of $25.0 million at December 31, 2016, resulting in an unrealized net gain on derivatives of $20.6 million for the three months ended March 31, 2017.

Table of Contents

Expenses

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

	Three Months Ended March 31,	
(In thousands, except expenses per BOE)	2018	2017
Expenses:		
Production taxes, transportation and processing	$17,791	$11,807
Lease operating	22,148	15,758
Plant and other midstream services operating	4,220	2,341
Depletion, depreciation and amortization	55,369	33,992
Accretion of asset retirement obligations	364	300
General and administrative	17,926	16,338
Total expenses	117,818	80,536
Operating income	73,362	54,278
Other income (expense):		
Net gain on asset sales and inventory impairment	—	7
Interest expense	(8,491)	(8,455)
Other income	53	70
Total other expense	(8,438)	(8,378)
Income before income taxes	64,924	45,900
Net income attributable to non-controlling interest in subsidiaries	(5,030)	(1,916)
Net income attributable to Matador Resources Company shareholders	$59,894	$43,984
Expenses per BOE:		
Production taxes, transportation and processing	$4.37	$3.98
Lease operating	$5.44	$5.31
Plant and other midstream services operating	$1.04	$0.79
Depletion, depreciation and amortization	$13.59	$11.45
General and administrative	$4.40	$5.50

Three Months Ended March 31, 2018 as Compared to Three Months Ended March 31, 2017

Production taxes, transportation and processing. Our production taxes, transportation and processing expenses increased $6.0 million to $17.8 million, or 51%, for the three months ended March 31, 2018, as compared to $11.8 million for the three months ended March 31, 2017. On a unit-of-production basis, our production taxes, transportation and processing expenses increased 10% to $4.37 per BOE for the three months ended March 31, 2018, as compared to $3.98 per BOE for the three months ended March 31, 2017. The increase in production taxes, transportation and processing expenses was primarily attributable to the $5.9 million increase in our production taxes to $13.1 million for the three months ended March 31, 2018, as compared to $7.2 million for the three months ended March 31, 2017, primarily due to the $67.1 million increase in oil and natural gas revenues for the three months ended March 31, 2018, as compared to the three months ended March 31, 2017. 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 our production tax expenses to increase proportionately.

Lease operating. Our lease operating expenses increased $6.4 million to $22.1 million, or an increase of 41%, for the three months ended March 31, 2018, as compared to $15.8 million for the three months ended March 31, 2017. Our lease operating expenses on a unit-of-production basis increased 2% to $5.44 per BOE for the three months ended March 31, 2018, as compared to $5.31 per BOE for the three months ended March 31, 2017. The increase in lease operating expenses for the three months ended March 31, 2018, as compared to the three months ended March 31, 2017, was primarily attributable to an increase in costs of services and equipment related to the increased number of wells at March 31, 2018, as compared to March 31, 2017, as a result of our increased delineation and development

drilling activities in the Delaware Basin.

Plant and other midstream services operating. Our plant and other midstream services operating expenses increased $1.9 million to $4.2 million, or an increase of 80%, for the three months ended March 31, 2018, as compared to $2.3 million for the three months ended March 31, 2017. This increase was partially attributable to (i) increased expenses associated with our expanded

Table of Contents

commercial salt water disposal operations to $2.2 million for the three months ended March 31, 2018, as compared to $1.5 million for the three months ended March 31, 2017, and (ii) increased expenses associated with the Black River Processing Plant to $1.7 million for the three months ended March 31, 2018, as compared to $0.8 million for the three months ended March 31, 2017.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased $21.4 million to $55.4 million, or an increase of 63%, for the three months ended March 31, 2018, as compared to $34.0 million for the three months ended March 31, 2017. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased to $13.59 per BOE for the three months ended March 31, 2018, as compared to $11.45 per BOE for the three months ended March 31, 2017. 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 and (ii) the 37% increase in total oil equivalent production to 4.1 million BOE for the three months ended March 31, 2018, as compared to 3.0 million BOE for the three months ended March 31, 2017. The impact of the increase in well costs and oil and natural gas production was partially offset by higher total proved oil and natural gas reserves at March 31, 2018, as compared to March 31, 2017. The increase in total proved oil and natural gas reserves was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin. In addition, depreciation expenses attributable to our midstream segment were approximately $1.5 million for the three months ended March 31, 2018, as compared to $1.2 million for the three months ended March 31, 2017.

General and administrative. Our general and administrative expenses increased $1.6 million to $17.9 million, or an increase of 10%, for the three months ended March 31, 2018, as compared to $16.3 million for the three months ended March 31, 2017. The increase in our general and administrative expenses was primarily attributable to increased payroll expenses of approximately $4.2 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 $1.7 million for the three months ended March 31, 2018, as compared to the three months ended March 31, 2017. As a result of the 37% increase in oil and natural gas production for the three months ended March 31, 2018, as compared to the three months ended March 31, 2017, our general and administrative expenses decreased 20% on a unit-of-production basis to $4.40 per BOE for the three months ended March 31, 2018, as compared to $5.50 per BOE for the three months ended March 31, 2017.

Interest expense. For the three months ended March 31, 2018, we incurred total interest expense of approximately $10.4 million. We capitalized approximately $1.9 million of our interest expense on certain qualifying projects for the three months ended March 31, 2018 and expensed the remaining $8.5 million to operations. For the three months ended March 31, 2017, we incurred total interest expense of approximately $9.7 million. We capitalized $1.2 million of our interest expense on certain qualifying projects for the three months ended March 31, 2017 and expensed the remaining $8.5 million to operations.

Total income tax benefit. Our deferred tax assets exceeded our deferred tax liabilities at March 31, 2018 due to the deferred tax amounts generated by 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 March 31, 2018 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 2018 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 2018 through a combination of cash on hand, operating cash flows and borrowings under our third amended and restated revolving credit agreement, as amended (the “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.

At March 31, 2018, we had cash totaling approximately $27.0 million and restricted cash totaling approximately $25.8 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 of our cash and is to be used only to fund the capital expenditures and operations of these less-than-wholly-owned subsidiaries.

During the first quarter of 2018, the lenders under our Credit Agreement completed their review of the Company's proved oil and natural gas reserves at December 31, 2017, and as a result, on March 5, 2018, the borrowing base was increased to $725.0 million and the maximum facility amount remained at $500.0 million. This March 2018 redetermination constituted the regularly scheduled May 1 redetermination. The Company elected to keep the lenders' borrowing commitment at $400.0 million. Borrowings under the Credit Agreement are limited to the lowest of the borrowing base, the maximum facility amount

Table of Contents

and the elected commitment. The Credit Agreement matures on October 16, 2020. At March 31, 2018, we had no outstanding borrowings under our Credit Agreement.

In April 2018, we accessed the line of credit under our Credit Agreement to fund certain of our acreage and mineral acquisitions, as well as for our ongoing exploration and development and midstream activities and for general corporate purposes. At May 2, 2018, we had $45.0 million in borrowings outstanding under our Credit Agreement and approximately $3.0 million in outstanding letters of credit issued pursuant to the Credit Agreement.

We expect that development of our Delaware Basin assets will be the primary focus of our operations and capital expenditures for the remainder of 2018. We plan to operate six contracted drilling rigs in the Delaware Basin throughout the remainder of 2018. One of the six rigs is also expected to drill at least two additional salt water disposal wells in the Rustler Breaks asset area for San Mateo during 2018. Our 2018 estimated capital expenditure budget consists of $530 to $570 million for drilling, completions, facilities and infrastructure and $70 to $90 million for midstream capital expenditures, which represents our 51% share of San Mateo's 2018 estimated capital expenditures. During the first quarter of 2018, we incurred capital expenditures of approximately $170.5 million for drilling, completions, facilities and infrastructure and approximately $23.3 million for midstream activities, which was 51% of San Mateo's capital expenditures of $45.7 million. Substantially all of our 2018 estimated capital expenditures will be allocated 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 and Haynesville shales to maintain and extend leases and to participate in certain non-operated well opportunities. Our 2018 Delaware Basin drilling program will focus on the continued development of the Wolf and Rustler Breaks asset areas and the further delineation and development of the Antelope Ridge, Jackson Trust, Ranger/Arrowhead and Twin Lakes asset areas, although we also anticipate continuing to delineate previously untested intervals in the Wolf and Rustler Breaks asset areas during 2018 as well. Depending on commodity prices, costs, opportunities in new asset areas like Antelope Ridge, liquidity and other factors, we may consider adding a seventh rig towards the end of 2018.

From January 1, 2018 through April 30, 2018, we acquired approximately 3,500 net leasehold and mineral acres, mostly in and around our existing acreage in the Delaware Basin, for a total acquisition cost of approximately $30 million. We intend to continue acquiring acreage and mineral interests, principally in the Delaware Basin, during the remainder of 2018. These expenditures are opportunity-specific and per-acre prices can vary significantly based on the prospect. As a result, it is difficult to estimate these 2018 capital expenditures with any degree of certainty; therefore, we have not provided estimated capital expenditures related to acreage and mineral acquisitions for 2018.

Our 2018 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, the ability of our joint venture partners to meet their 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 2018 is expected to come from producing wells and development activities on currently proved properties in the Wolfcamp and Bone Spring plays in the Delaware Basin, the Eagle Ford shale in South Texas and the Haynesville shale in Louisiana. Our existing wells may not produce at the levels we have forecasted 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 2018 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 liquid ("NGL") prices and to partially offset reductions in our cash flows from operations resulting from declines in commodity prices. See Note 7 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for a summary of our open derivative financial instruments at March 31, 2018.

Table of Contents

Our unaudited cash flows for the three months ended March 31, 2018 and 2017 are presented below:

	Three Months Ended March 31,	
(In thousands)	2018	2017
Net cash provided by operating activities	$136,149	$61,309
Net cash used in investing activities	(220,754)	(224,974)
Net cash provided by financing activities	34,906	173,832
Net change in cash	$(49,699)	$10,167
Adjusted EBITDA attributable to Matador Resources Company shareholders [1]	$117,254	$69,959

(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 $74.8 million to $136.1 million for the three months ended March 31, 2018 from $61.3 million for the three months ended March 31, 2017. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased to $114.8 million for the three months ended March 31, 2018 from $63.8 million for the three months ended March 31, 2017. This increase was primarily attributable to higher oil and natural gas production and higher oil prices. Changes in our operating assets and liabilities between the two periods resulted in a net increase of approximately $23.8 million in net cash provided by operating activities for the three months ended March 31, 2018, as compared to the three months ended March 31, 2017.

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 NGL prices. In addition, we attempt to avoid long-term service agreements where possible in order to minimize ongoing future commitments.

Cash Flows Used in Investing Activities

Net cash used in investing activities decreased by $4.2 million to $220.8 million for the three months ended March 31, 2018 from $225.0 million for the three months ended March 31, 2017. This decrease in net cash used in investing activities is primarily due to a decrease of $21.0 million in oil and natural gas properties capital expenditures for the three months ended March 31, 2018, as compared to the three months ended March 31, 2017. Cash used for oil and natural gas properties capital expenditures for the three months ended March 31, 2018 was primarily attributable to the acquisition of additional leasehold and mineral interests and to our operated drilling and completion activities in the Delaware Basin. This decrease was partially offset by an increase in cash used for midstream and other property and equipment of approximately $16.5 million primarily related to capital expenditures for San Mateo.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities decreased by $138.9 million to $34.9 million for the three months ended March 31, 2018 from $173.8 million for the three months ended March 31, 2017. During the three months ended March 31, 2018, we received net proceeds of $14.7 million attributable to performance incentives related to the formation of San Mateo as well as net cash of $24.5 million attributable to contributions from and distributions to the non-controlling interest owners of less-than-wholly-owned subsidiaries. During the three months ended March 31, 2017, we received net proceeds of $171.5 million related to the formation of San Mateo.

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

Table of Contents

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.

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

	Three Months Ended March 31,	
(In thousands)	2018	2017
Unaudited Adjusted EBITDA Reconciliation to Net Income:		
Net income attributable to Matador Resources Company shareholders	$59,894	$43,984
Net income attributable to non-controlling interest in subsidiaries	5,030	1,916
Net income	64,924	45,900
Interest expense	8,491	8,455
Depletion, depreciation and amortization	55,369	33,992
Accretion of asset retirement obligations	364	300
Unrealized gain on derivatives	(10,416)	(20,631)
Stock-based compensation expense	4,179	4,166
Net gain on asset sales and inventory impairment	—	(7)
Consolidated Adjusted EBITDA	122,911	72,175
Adjusted EBITDA attributable to non-controlling interest in subsidiaries	(5,657)	(2,216)
Adjusted EBITDA attributable to Matador Resources Company shareholders	$117,254	$69,959

	Three Months Ended March 31,	
(In thousands)	2018	2017
Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities:		
Net cash provided by operating activities	$136,149	$61,309
Net change in operating assets and liabilities	(21,364)	2,455
Interest expense, net of non-cash portion	8,126	8,411
Adjusted EBITDA attributable to non-controlling interest in subsidiaries	(5,657)	(2,216)
Adjusted EBITDA attributable to Matador Resources Company shareholders	$117,254	$69,959

Net income attributable to Matador Resources Company shareholders increased by $15.9 million to $59.9 million for the three months ended March 31, 2018, as compared to $44.0 million for the three months ended March 31, 2017. This increase in net income attributable to Matador Resources Company shareholders for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017 is primarily attributable to the increase in oil and natural gas revenues of $67.1 million partially offset by a $10.2 million decrease in unrealized gain on derivatives and a $37.3 million increase in total expenses, including a $21.4 million increase in depletion, depreciation and amortization expenses.

Our Adjusted EBITDA, a non-GAAP financial measure, increased by $47.3 million to $117.3 million for the three months ended March 31, 2018, as compared to $70.0 million for the three months ended March 31, 2017. This increase in our Adjusted EBITDA is primarily attributable to higher oil and natural gas production and higher oil prices for the three months ended March 31, 2018, as compared to the three months ended March 31, 2017.

32

Table of Contents

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 March 31, 2018, 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 and disposal 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, transportation and disposal 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 9 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 March 31, 2018:

	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]	$2,100	$—	$—	$2,100	$—
Senior unsecured notes[2]	575,000	—	—	—	575,000
Office leases	21,995	2,493	5,172	5,491	8,839
Non-operated drilling commitments[3]	30,128	30,128	—	—	—
Drilling rig contracts[4]	32,738	26,504	6,234	—	—
Asset retirement obligations	26,956	1,274	848	2,014	22,820
Natural gas transportation, gathering and processing agreements with non-affiliates[5]	203,949	10,284	36,172	45,046	112,447
Gathering processing and disposal agreements with San Mateo[6]	225,576	5,275	69,994	75,102	75,205
Natural gas construction contracts[7]	16,124	16,124	—	—	—
Total contractual cash obligations	$1,134,566	$92,082	$118,420	$129,753	$794,311

(1) At March 31, 2018, we had no borrowings outstanding under our Credit Agreement and approximately $2.1 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. Interest expense on our 6.875% senior notes due 2023 that are outstanding as of March 31, 2018 is expected to be approximately $39.5 million each year until maturity.

(3) At March 31, 2018, 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 March 31, 2018. If all of these wells are drilled and completed, we will have minimum outstanding aggregate commitments for our participation in these wells of approximately $30.1 million at March 31, 2018, 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 9 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for more information regarding these contractual commitments.

(5) In late 2015, we entered into a 15-year fixed-fee natural gas gathering and processing agreement for a significant portion of our operated natural gas production in Loving County, Texas. In late 2017, we entered into an 18-year

fixed-fee natural gas transportation agreement where we committed to deliver a portion of the residue natural gas production at the tailgate of the Black River Processing Plant to transport through the counterparty's pipeline in Eddy County, New Mexico. In late 2017, we also entered into a fixed-fee NGL transportation and fractionation agreement whereby we committed to deliver our NGL production at the tailgate of the Black River Processing Plant. We have committed to deliver a minimum amount of NGLs to the counterparty upon construction and completion of a pipeline expansion and a fractionation facility by the counterparty, which is currently expected to be completed late in 2019. We have no rights to compel the counterparty to construct this pipeline extension or fractionation facility. If the counterparty does not construct the pipeline extension and fractionation facility, then we do not have any minimum volume commitments under the agreement. If the counterparty constructs the pipeline extension and fractionation facility on or prior to February 28, 2021, then we will have a commitment to deliver a minimum amount of NGLs for seven years following the completion of the pipeline extension and fractionation facility. If we do not meet our NGL volume commitment in any quarter during the seven-year commitment period, we will be required to pay a deficiency fee per gallon of NGL deficiency. The amounts in the table assume that the seven-year period containing minimum NGL volume commitments begins in late 2019. See Note 9 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for more information regarding these contractual commitments.

Table of Contents

(6) In February 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 9 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for more information regarding these 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. In addition, during the first quarter of 2018, a subsidiary of San Mateo entered into agreements for additional field compression and an amine gas treatment unit to maximize the operation of the Black River Processing Plant. See Note 9 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for more information regarding these contractual commitments.

General Outlook and Trends

For the three months ended March 31, 2018, oil prices averaged $62.86 per Bbl, ranging from a high of $66.14 per Bbl in late January to a low of $59.19 per Bbl in mid-February, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. We realized a weighted average oil price of $62.20 per Bbl ($60.40 per Bbl including realized losses from oil derivatives) for our oil production for the three months ended March 31, 2018, as compared to $50.72 per Bbl ($49.73 per Bbl including realized losses from oil derivatives) for the three months ended March 31, 2017. At May 2, 2018, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date had increased from the average price for the first quarter of 2018, settling at $67.93 per Bbl, which was a significant increase as compared to $47.66 per Bbl at May 2, 2017.

For the three months ended March 31, 2018, natural gas prices averaged $2.85 per MMBtu, ranging from a high of approximately $3.63 per MMBtu in late January to a low of approximately $2.55 per MMBtu in mid-February, 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 $3.33 per Mcf (with essentially no realized gains or losses from natural gas derivatives) for our natural gas production (including revenues attributable to NGLs) for the three months ended March 31, 2018, as compared to $3.94 per Mcf ($3.86 per Mcf, including realized losses from natural gas derivatives) for the three months ended March 31, 2017. At May 2, 2018, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date had decreased from the average price for the first quarter of 2018, settling at $2.76 per MMBtu, which was also a decrease as compared to $3.20 per MMBtu at May 2, 2017.

The prices we receive for oil, natural gas and NGLs heavily influence our revenue, profitability, cash flow available for capital expenditures, access to capital and future rate of growth. Oil, natural gas and NGLs 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 NGLs have been volatile and these markets will likely continue to be volatile in the future. Declines in oil, natural gas or NGL prices not only reduce our revenues, but could also reduce the amount of oil, natural gas and NGLs 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 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 NGL 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 NGL 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.

In addition, the prices we receive for our oil and natural gas production, in particular, often reflect a discount to the relevant benchmark prices, such as the NYMEX West Texas Intermediate oil price or the NYMEX Henry Hub natural gas price. The difference between these benchmark prices and the price we receive is called a differential. At March 31, 2018, most of our oil production from the Delaware Basin was sold based on prices established in Midland, Texas and most of our natural gas production from the Delaware Basin was sold based on prices established at the Waha Hub in far West Texas. During the first quarter of 2018, the price differentials for oil sold in Midland and natural gas

sold at the Waha Hub compared to the benchmark prices for oil and natural gas, respectively, began to widen significantly. Although these widening differentials did not significantly impact our oil and natural gas revenues in the first quarter of 2018, these widening differentials are expected to negatively impact our oil and natural gas revenues beginning in the second quarter of 2018.

In early May 2018, these price differentials were approximately ($10.00) per barrel for oil and ($1.50) per MMBtu for natural gas. We anticipate that these widening price differentials could persist for 12 to 18 months or longer until additional oil and natural gas pipeline capacity from West Texas to the Texas Gulf Coast and other end markets is completed; however, we can provide no assurances as to how long these widening differentials may persist and, in fact, these price differentials could widen further in future periods. At May 2, 2018, we had approximately 55% of our anticipated Delaware Basin oil production for the remainder of 2018 hedged at a weighted average basis differential swap price of ($1.02) per barrel to help mitigate our exposure to these widening oil basis differentials. See Note 7 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for a summary of these oil basis swaps. At May 2, 2018, we had no hedges in place to mitigate our exposure to basis differentials for our natural gas production.

Table of Contents

Coinciding with the improvements in oil and natural gas prices since the latter part of 2016, we have experienced price increases from certain of 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 or 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 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 NGL price declines, however, drilling certain oil or natural gas wells may not be economic, 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.

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, 2017, 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 NGLs 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 NGL prices. Traditional costless collars provide us with downside price protection through the purchase of a put option that is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, these arrangements are initially “costless” to us. Participating three-way costless collars also provide the Company with downside price protection through the purchase of a put option, but they also allow the Company to participate in price upside through the purchase of a call option; the purchase of both the put option and the call option are financed through the sale of a call option. Because the proceeds from the call option sale are used to offset the cost of the purchased put and call options, these arrangements are also initially “costless” to the Company. In the case of a costless collar, the put option and the call option or options 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 March 31, 2018, RBC, 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 7 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for a summary of our open derivative financial instruments at March 31, 2018. 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 March 31, 2018 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.

Table of Contents

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls during the three months ended March 31, 2018 that have materially affected or are reasonably likely to have a material effect on our internal control over financial reporting.

Table of Contents

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 March 31, 2018, 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
January 1, 2018 to January 31, 2018	25,529	$ 31.70	—	—
February 1, 2018 to February 28, 2018	45,503	29.52	—	—
March 1, 2018 to March 31, 2018	8,175	28.78	—	—
Total	79,207	$ 30.15	—	—

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

Item 6. Exhibits

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

Table of Contents

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: May 3, 2018 By: /s/ Joseph Wm. Foran
Joseph Wm. Foran
Chairman and Chief Executive Officer

Date: May 3, 2018 By: /s/ David E. Lancaster
David E. Lancaster
Executive Vice President and Chief Financial Officer

Table of Contents

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 the Registration Statement on Form S-1 filed on August 12, 2011).
3.2	Amended and Restated Certificate of Formation of Matador Resources Company (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).
3.3	Certificate of Amendment to the Amended and Restated Certificate of Formation of Matador Resources Company dated April 2, 2015 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).
3.4	Certificate of Amendment to the Amended and Restated Certificate of Formation of Matador Resources Company effective June 2, 2017 (incorporated by reference to Exhibit 3.4 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).
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 February 22, 2018).
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).
101	The following financial information from Matador Resources Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018 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).