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

FORM 10-Q

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

For the quarterly period ended September 30, 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 every Interactive Data File required to be submitted 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 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	☐	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 October 31, 2018, there were 116,333,766 shares of the registrant’s common stock, par value $0.01 per share, outstanding.

MATADOR RESOURCES COMPANY
FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 2018

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Part I — FINANCIAL INFORMATION

Item 1. Financial Statements — Unaudited

Matador Resources Company and Subsidiaries

CONDENSED CONSOLIDATED BALANCE SHEETS — UNAUDITED
(In thousands, except par value and share data)

	September 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash	$ 45,942	$ 96,505
Restricted cash	7,066	5,977
Accounts receivable		
Oil and natural gas revenues	81,422	65,962
Joint interest billings	55,390	67,225
Other	10,060	8,031
Derivative instruments	4	1,190
Lease and well equipment inventory	18,758	5,993
Prepaid expenses and other assets	6,790	6,287
Total current assets	225,432	257,170
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	3,506,479	3,004,770
Unproved and unevaluated	1,241,529	637,396
Midstream and other property and equipment	408,436	281,096
Less accumulated depletion, depreciation and amortization	(2,234,470)	(2,041,806)
Net property and equipment	2,921,974	1,881,456
Other assets	6,796	7,064
Total assets	$ 3,154,202	$ 2,145,690
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 32,491	$ 11,757
Accrued liabilities	178,830	174,348
Royalties payable	67,023	61,358
Amounts due to affiliates	12,998	10,302
Derivative instruments	19,740	16,429
Advances from joint interest owners	12,354	2,789
Amounts due to joint ventures	2,373	4,873
Other current liabilities	942	750
Total current liabilities	326,751	282,606
Long-term liabilities		
Borrowings under Credit Agreement	325,000	—
Senior unsecured notes payable	740,063	574,073
Asset retirement obligations	28,706	25,080
Derivative instruments	4,996	—
Other long-term liabilities	6,243	6,385
Total long-term liabilities	1,105,008	605,538
Commitments and contingencies (Note 9)		
Shareholders' equity		
Common stock - $0.01 par value, 160,000,000 shares authorized; 116,506,743 and 108,513,597 shares issued; and 116,348,548 and 108,510,160 shares outstanding, respectively	1,165	1,085
Additional paid-in capital	1,923,030	1,666,024
Accumulated deficit	(372,990)	(510,484)
Treasury stock, at cost, 158,195 and 3,437 shares, respectively	(4,039)	(69)
Total Matador Resources Company shareholders' equity	1,547,166	1,156,556
Non-controlling interest in subsidiaries	175,277	100,990
Total shareholders' equity	1,722,443	1,257,546
Total liabilities and shareholders' equity	$ 3,154,202	$ 2,145,690

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

Matador Resources Company and Subsidiaries

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS — UNAUDITED
(In thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	**2017**	**2018**	**2017**
Revenues				
Oil and natural gas revenues	$ 216,282	$ 134,948	$ 607,255	$ 363,559
Third-party midstream services revenues	6,809	3,218	13,284	6,871
Realized gain (loss) on derivatives	5,424	485	(1,322)	(1,176)
Unrealized (loss) gain on derivatives	(21,337)	(12,372)	(9,492)	21,449
Total revenues	207,178	126,279	609,725	390,703
Expenses				
Production taxes, transportation and processing	20,215	15,666	58,116	40,348
Lease operating	22,531	16,689	69,685	48,486
Plant and other midstream services operating	7,291	3,096	17,187	8,379
Depletion, depreciation and amortization	70,457	47,800	192,664	123,066
Accretion of asset retirement obligations	387	323	1,126	937
General and administrative	18,444	16,156	55,739	49,671
Total expenses	139,325	99,730	394,517	270,887
Operating income	67,853	26,549	215,208	119,816
Other income (expense)				
Net (loss) gain on asset sales and inventory impairment	(196)	16	(196)	23
Interest expense	(10,340)	(8,550)	(26,835)	(26,229)
Prepayment premium on extinguishment of debt	(31,226)	—	(31,226)	—
Other (expense) income	(976)	(36)	(1,275)	1,956
Total other expense	(42,738)	(8,570)	(59,532)	(24,250)
Net income	25,115	17,979	155,676	95,566
Net income attributable to non-controlling interest in subsidiaries	(7,321)	(2,940)	(18,182)	(8,034)
Net income attributable to Matador Resources Company shareholders	$ 17,794	$ 15,039	$ 137,494	$ 87,532
Earnings per common share				
Basic	$ 0.15	$ 0.15	$ 1.22	$ 0.87
Diluted	$ 0.15	$ 0.15	$ 1.21	$ 0.87
Weighted average common shares outstanding				
Basic	116,358	100,365	112,659	100,141
Diluted	116,912	100,504	113,208	100,580

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

Matador Resources Company and Subsidiaries

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY — UNAUDITED
(In thousands)

For the Nine Months Ended September 30, 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	736	7	(7)	—	—	—	—	—	—
Issuance of common stock	7,000	70	226,542	—	—	—	226,612	—	226,612
Cost to issue equity	—	—	(146)	—	—	—	(146)	—	(146)
Issuance of common stock pursuant to directors' and advisors' compensation plan	79	1	(1)	—	—	—	—	—	—
Stock-based compensation expense related to equity-based awards including amounts capitalized	—	—	17,174	—	—	—	17,174	—	17,174
Stock options exercised, net of options forfeited in net share settlements	178	2	(1,256)	—	—	—	(1,254)	—	(1,254)
Restricted stock forfeited	—	—	—	—	155	(3,970)	(3,970)	—	(3,970)
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	—	—	—	—	—	—	—	73,500	73,500
Distributions to non-controlling interest owners of less-than-wholly-owned subsidiaries	—	—	—	—	—	—	—	(17,395)	(17,395)
Current period net income	—	—	—	137,494	—	—	137,494	18,182	155,676
Balance at September 30, 2018	116,507	$ 1,165	$ 1,923,030	$ (372,990)	158	$ (4,039)	$ 1,547,166	$ 175,277	$ 1,722,443

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

Matador Resources Company and Subsidiaries

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS — UNAUDITED
(In thousands)

	Nine Months Ended September 30,	
	2018	**2017**
Operating activities		
Net income	$ 155,676	$ 95,566
Adjustments to reconcile net income to net cash provided by operating activities		
Unrealized loss (gain) on derivatives	9,492	(21,449)
Depletion, depreciation and amortization	192,664	123,066
Accretion of asset retirement obligations	1,126	937
Stock-based compensation expense	13,787	12,488
Prepayment premium on extinguishment of debt	31,226	—
Amortization of debt issuance cost	851	103
Net loss (gain) on asset sales and inventory impairment	196	(23)
Changes in operating assets and liabilities		
Accounts receivable	(5,654)	(50,343)
Lease and well equipment inventory	(15,347)	(1,666)
Prepaid expenses	(502)	(2,224)
Other assets	—	217
Accounts payable, accrued liabilities and other current liabilities	20,823	35,068
Royalties payable	5,665	29,651
Advances from joint interest owners	9,565	2,646
Other long-term liabilities	(250)	(1,521)
Net cash provided by operating activities	419,318	222,516
Investing activities		
Oil and natural gas properties capital expenditures	(1,106,556)	(517,270)
Expenditures for midstream and other property and equipment	(122,239)	(80,560)
Proceeds from sale of assets	8,267	977
Net cash used in investing activities	(1,220,528)	(596,853)
Financing activities		
Repayments of borrowings	(45,000)	—
Borrowings under Credit Agreement	370,000	—
Proceeds from issuance of senior unsecured notes	750,000	—
Cost to issue senior unsecured notes	(9,531)	—
Purchase of senior unsecured notes	(605,780)	—
Proceeds from issuance of common stock	226,612	—
Cost to issue equity	(146)	—
Proceeds from stock options exercised	827	2,920
Contributions related to formation of Joint Venture	14,700	171,500
Contributions from non-controlling interest owners of less-than-wholly-owned subsidiaries	73,500	29,400
Distributions to non-controlling interest owners of less-than-wholly-owned subsidiaries	(17,395)	(5,635)
Taxes paid related to net share settlement of stock-based compensation	(6,051)	(4,415)
Purchase of non-controlling interest of less-than-wholly-owned subsidiary	—	(2,653)
Net cash provided by financing activities	751,736	191,117
Decrease in cash and restricted cash	(49,474)	(183,220)
Cash and restricted cash at beginning of period	102,482	214,142
Cash and restricted cash at end of period	$ 53,008	$ 30,922

Supplemental disclosures of cash flow information (Note 10)

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

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED

NOTE 1 — NATURE OF OPERATIONS

Matador Resources Company, a Texas corporation ("Matador" and, collectively with its subsidiaries, the "Company"), is an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. The Company's current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the 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, *Consolidation (Topic 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 September 30, 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 Update 2014-09, *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 did 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. With the adoption of ASC 606, revenue from these contracts is recognized in accordance with the five-step revenue recognition model prescribed in

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

ASC 606. Specifically, revenue is 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 at or 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, if necessary, natural gas liquid (“NGL”) products are extracted. The NGL products and remaining residue gas are then sold by the purchaser, or if the Company elects to repurchase the natural gas, 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 the Company’s 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 on its consolidated financial statements as a result of adoption of ASC 606 was a $2.8 million and $7.6 million decrease in oil and natural gas revenues and a $2.8 million and $7.6 million decrease in production taxes, transportation and processing expenses for the three and nine months ended September 30, 2018, respectively, which was not material. As a result of adoption of this standard, the Company is now required to disclose the following information regarding total revenues and revenues from contracts with customers on a disaggregated basis for the three and nine months ended September 30, 2018 (in thousands).

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2018
Revenues from contracts with customers	$ 223,091	$ 620,539
Realized gain (loss) on derivatives	5,424	(1,322)
Unrealized loss on derivatives	(21,337)	(9,492)
Total revenues	$ 207,178	$ 609,725

	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2018
Oil revenues	$ 169,913	$ 484,343
Natural gas revenues	46,369	122,912
Third-party midstream services revenues	6,809	13,284
Total revenues from contracts with customers	$ 223,091	$ 620,539

The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical expedient in accordance with ASC 606. The expedient, 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 nine months ended September 30, 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 and nine months ended September 30, 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 $8.5 million and $6.1 million of its general and administrative costs for the three months ended September 30, 2018 and 2017, respectively, and approximately $1.7 million and $2.1 million of its interest expense for the three months ended September 30, 2018 and 2017, respectively. The Company capitalized approximately $22.6 million and $16.9 million of its general and administrative costs for the nine months ended September 30, 2018 and 2017, respectively, and approximately $6.2 million and $5.2 million of its interest expense for the nine months ended September 30, 2018 and 2017, respectively.

On September 12, 2018, the Company announced the successful acquisition of 8,400 gross (8,400 net) leasehold acres in Lea and Eddy Counties, New Mexico for approximately $387 million in the Bureau of Land Management New Mexico Oil and Gas Lease Sale on September 5 and 6, 2018 (the "BLM Acquisition").

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

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 and nine months ended September 30, 2018 and 2017 (in thousands).

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Weighted average common shares outstanding				
Basic	116,358	100,365	112,659	100,141
Dilutive effect of options and restricted stock units	554	139	549	439
Diluted weighted average common shares outstanding	116,912	100,504	113,208	100,580

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. The Company plans to use this practical expedient, and as a result, the Company will evaluate new or modified land easements under this ASU beginning at the date of adoption. In July 2018, the FASB issued ASU 2018-11, *Leases (Topic 842)*, which is a targeted improvement for comparative reporting requirements for initial adoption of ASU 2016-02. The Company plans to use the optional transition method to adopt ASU 2016-02, and the amendments provided for in ASU 2018-11 will allow the Company to initially apply the new lease standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period 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, and quantifying the impact of the new lease standard on existing leases. The Company expects to adopt these ASUs as of January 1, 2019.

Stock Compensation. In June 2018, the FASB issued ASU 2018-07, *Compensation - Stock Compensation (Topic 718): Improvements to Nonemployee Share-Based Payment Accounting*. This ASU extends the scope of Topic 718 to include share-based payment transactions related to the acquisition of goods and services from nonemployees. Currently, the Company accounts for stock-based awards to special advisors and contractors under ASC 505-50 as liability instruments, and the fair value of the awards is recalculated each reporting period. Upon adoption, all such awards will be measured at fair value on the grant date and the resulting expense will be recognized on a straight-line basis over the awards' vesting period. This ASU is effective for fiscal years beginning after December 15, 2018 with early adoption permitted. The transitional guidance requires entities to remeasure all unvested awards that are being accounted for under ASC 505-50 as liability instruments as of the beginning of the year in which this ASU is adopted. The Company expects to adopt this ASU as of January 1, 2019 and does not anticipate this ASU will have a material impact on the Company's consolidated financial statements.

NOTE 3 — ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company's asset retirement obligations for the nine months ended September 30, 2018 (in thousands).

Beginning asset retirement obligations	$ 26,256
Liabilities incurred during period	2,473
Liabilities settled during period	(663)
Revisions in estimated cash flows	442
Accretion expense	1,126
Ending asset retirement obligations	29,634
Less: current asset retirement obligations[1]	(928)
Long-term asset retirement obligations	$ 28,706

(1) Included in accrued liabilities in the Company's interim unaudited condensed consolidated balance sheet at September 30, 2018.

NOTE 4 — DEBT

At September 30, 2018, the Company had $750.0 million of outstanding 5.875% senior notes due 2026 (the "Original 2026 Notes"), $325.0 million in borrowings outstanding under the Company's revolving credit agreement (the "Credit Agreement") and approximately $3.0 million in outstanding letters of credit issued pursuant to the Credit Agreement. At October 31, 2018, the Company had $1.05 billion of outstanding Notes (as defined below), $25.0 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, in March 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 at September 30, 2018.

In October 2018, the lenders completed their review of the Company's proved oil and natural gas reserves at June 30, 2018. In connection with such review, the Company amended the Credit Agreement to, among other items, increase the maximum facility amount to $1.5 billion, increase the borrowing base to $850.0 million, increase the elected borrowing commitment to $500.0 million, extend the maturity to October 31, 2023 and reduce borrowing rates by 0.25% per annum. This October 2018 redetermination constituted the regularly scheduled November 1 redetermination. Borrowings under the Credit Agreement are limited to the lowest of the borrowing base, the maximum facility amount and the elected borrowing commitment.

The Company believes that it was in compliance with the terms of the Credit Agreement at September 30, 2018.

Senior Unsecured Notes

As of June 30, 2018, the Company had $575.0 million of outstanding 6.875% senior notes due 2023 (the "2023 Notes"). On August 21, 2018, the Company issued $750.0 million of Original 2026 Notes in a private placement (the "2026 Notes Offering"). The Original 2026 Notes were issued at par value with a coupon rate of 5.875%, and the Company received net proceeds of approximately $740.0 million, after deducting the initial purchasers' discounts and offering expenses. In conjunction with the 2026 Notes Offering, in August and September 2018, respectively, the Company completed a tender offer to purchase for cash and subsequent redemption of all of the Company's $575.0 million aggregate principal amount of 2023 Notes (the "2023 Notes Tender Offer and Redemption"). The Company used a portion of the net proceeds from the 2026 Notes Offering to fund the 2023 Notes Tender Offer and Redemption. In connection with the 2023 Notes Tender Offer and Redemption, the Company incurred a loss of $31.2 million, including total payments of $30.4 million to holders of the 2023

NOTE 4 — DEBT — Continued

Notes as a result of the tender premium and the required 105.156% redemption price payable pursuant to the 2023 Notes indenture.

On October 4, 2018, the Company issued an additional $300.0 million of 5.875% senior unsecured notes due 2026 (the “Additional 2026 Notes” and, collectively with the Original 2026 Notes, the “Notes”). The Additional 2026 Notes were issued pursuant to, and are governed by, the same indenture governing the Original 2026 Notes (the “Indenture”). The Additional 2026 Notes were issued at 100.5% of par, plus accrued interest from August 21, 2018. The Company received net proceeds from this offering of approximately $297.6 million, after deducting the initial purchasers’ discounts and estimated offering expenses but excluding accrued interest from August 21, 2018 paid by the initial purchasers of the Additional 2026 Notes. The proceeds from this offering were used to repay a portion of the outstanding borrowings under the Credit Agreement, which were incurred in connection with the BLM Acquisition. The Notes will mature September 15, 2026, and interest is payable on the Notes semi-annually in arrears on each March 15 and September 15. The Notes are guaranteed on a senior unsecured basis by certain subsidiaries of the Company (the “Guarantors”).

On or after September 15, 2021, the Company may redeem all or a part of the Notes at any time or from time to time at the following redemption prices (expressed as percentages of principal amount) plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the twelve-month period beginning on September 15 of the years indicated below:

Year	Redemption Price
2021	104.406%
2022	102.938%
2023	101.469%
2024 and thereafter	100.000%

At any time prior to September 15, 2021, the Company may redeem up to 35% of the aggregate principal amount of the Notes with net proceeds from certain equity offerings at a redemption price of 105.875% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date, provided that (i) at least 65% in aggregate principal amount of the Notes (including any additional notes) originally issued remains outstanding immediately after the occurrence of such redemption (excluding Notes held by the Company and its subsidiaries) and (ii) each such redemption occurs within 180 days of the date of the closing of the related equity offering.

In addition, at any time prior to September 15, 2021, the Company may redeem all or part of the Notes at a redemption price equal to the sum of:

(i) the principal amount thereof, plus

(ii) the excess, if any, of (a) the present value at such time of (1) the redemption price of such Notes at September 15, 2021 plus (2) any required interest payments due on such Notes through September 15, 2021, discounted to the redemption date on a semi-annual basis using a discount rate equal to the Treasury Rate (as defined in the Indenture) plus 50 basis points, over (b) the principal amount of such Notes, plus

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

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

- incur additional indebtedness;
- sell assets;
- pay dividends or make certain investments;
- create liens that secure indebtedness;
- enter into transactions with affiliates; and
- merge or consolidate with another company.

NOTE 4 — DEBT — Continued

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

- default for 30 days in the payment when due of interest on the Notes;
- default in the payment when due of the principal of, or premium, if any, on the Notes;
- failure by the Company to comply with its obligations to offer to purchase or purchase notes pursuant to the change of control or asset sale covenants of the Indenture or to comply with the covenant relating to mergers;
- failure by the Company for 180 days after notice to comply with its reporting obligations under the Indenture;
- failure by the Company for 60 days after notice to comply with any of the other agreements in the Indenture;
- payment defaults and accelerations with respect to other indebtedness of the Company and its Restricted Subsidiaries in the aggregate principal amount of $50.0 million or more;
- failure by the Company or any Restricted Subsidiary to pay certain final judgments aggregating in excess of $50.0 million within 60 days;
- any subsidiary guarantee by a Guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker; and
- certain events of bankruptcy or insolvency with respect to the Company or any Restricted Subsidiary that is a Significant Subsidiary or any group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary.

NOTE 5 — INCOME TAXES

The Company’s deferred tax assets exceeded its deferred tax liabilities at September 30, 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 September 30, 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.

NOTE 6 — EQUITY

Equity Offering

On May 17, 2018, the Company completed a public offering of 7,000,000 shares of its common stock. After deducting offering costs totaling approximately $0.1 million, the Company received net proceeds of approximately $226.5 million. The proceeds from this offering were used to acquire additional leasehold and mineral acres in the Delaware Basin, to fund certain midstream initiatives in the Delaware Basin and for general corporate purposes, including to fund a portion of the Company's capital expenditures. Pending such uses, the Company used a portion of the proceeds from the offering to repay the $45.0 million in borrowings then outstanding under the Credit Agreement and invested the remaining funds in short-term marketable securities.

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 Incentives

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 during the nine months ended September 30, 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. These performance incentives for the nine months ended September 30, 2018 are also denoted as "Contributions related to formation of Joint Venture" under "Financing activities" in the Company's condensed consolidated statements of cash flows.

NOTE 7 — DERIVATIVE FINANCIAL INSTRUMENTS

At September 30, 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 and 2019.

The following is a summary of the Company's open costless collar contracts for oil and natural gas at September 30, 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]	10/01/2018 - 12/31/2018	720,000	$ 44.27	$ 60.29	$ (9,240)
Oil - WTI[1]	01/01/2019 - 12/31/2019	2,400,000	$ 50.00	$ 64.75	(21,287)
Oil - LLS[2]	10/01/2018 - 12/31/2018	180,000	$ 45.00	$ 63.05	(2,973)
Natural Gas	10/01/2018 - 12/31/2018	4,200,000	$ 2.58	$ 3.67	(18)
Total open costless collar contracts					$ (33,518)

(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 September 30, 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]	10/01/2018 - 12/31/2018	480,000	$ 50.08	$ 63.50	$ 66.68	$ (1,369)
Total open three-way costless collar contracts						$ (1,369)

(1) NYMEX West Texas Intermediate crude oil.

The following is a summary of the Company's open basis swap contracts for oil at September 30, 2018.

Commodity	Calculation Period	Notional Quantity (Bbl)	Fixed Price ($/Bbl)	Fair Value of Asset (Liability) (thousands)
Oil Basis Swaps	10/01/2018 - 12/31/2018	1,305,000	$ (1.02)	$ 10,155
Total open swap contracts				$ 10,155

At September 30, 2018, the Company had an aggregate liability for open derivative financial instruments of $24.7 million.

The Company's 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.

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 September 30, 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
September 30, 2018			
Current assets	$ 49,723	$ (49,719)	$ 4
Other assets	654	(654)	—
Current liabilities	(69,459)	49,719	(19,740)
Long-term liabilities	(5,650)	654	(4,996)
Total	$ (24,732)	$ —	$ (24,732)
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 September 30,		Nine Months Ended September 30,	
Type of Instrument	**Location in Condensed Consolidated Statement of Operations**	**2018**	**2017**	**2018**	**2017**
Derivative Instrument					
Oil	Revenues: Realized gain (loss) on derivatives	$ 5,424	$ 485	$ (1,373)	$ (568)
Natural Gas	Revenues: Realized gain (loss) on derivatives	—	—	51	(608)
Realized gain (loss) on derivatives		5,424	485	(1,322)	(1,176)
Oil	Revenues: Unrealized (loss) gain on derivatives	(21,240)	(12,479)	(8,284)	15,949
Natural Gas	Revenues: Unrealized (loss) gain on derivatives	(97)	115	(1,208)	5,508
NGL	Revenues: Unrealized loss on derivatives	—	(8)	—	(8)
Unrealized (loss) gain on derivatives		(21,337)	(12,372)	(9,492)	21,449
Total		$ (15,913)	$ (11,887)	$ (10,814)	$ 20,273

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 September 30, 2018 and December 31, 2017 (in thousands).

	Fair Value Measurements at September 30, 2018 using			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets (Liabilities)				
Natural gas derivatives	$ —	$ (18)	$ —	$ (18)
Oil derivatives and basis swaps	—	(24,714)	—	(24,714)
Total	$ —	$ (24,732)	$ —	$ (24,732)

	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 September 30, 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 September 30, 2018, the carrying value of borrowings under the Credit Agreement approximated its fair value as it is subject to short-term floating interest rates that reflect market rates available to the Company at the time and is classified at Level 2.

NOTE 8 — FAIR VALUE MEASUREMENTS — Continued

At September 30, 2018 and December 31, 2017, the fair value of the Original 2026 Notes and the 2023 Notes was $761.3 million and $614.1 million, respectively, based on quoted market prices, which represent Level 1 inputs in the fair value hierarchy.

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 minimum commitment. If the Company ceased operations in this area at September 30, 2018, the total deficiency fee required to be paid would be approximately $12.5 million. In addition, if the Company elects to reduce the gathering and processing commitment in any year, the Company has the ability to elect to increase the committed volumes in any future year to the originally agreed gathering and processing commitment. Any quantity in excess of the volume commitment delivered in a contract year can be carried over to the next contract year for purposes of calculating that year’s natural gas deficiency. The Company paid approximately $4.8 million and $4.0 million in natural gas processing and gathering fees under this agreement during the three months ended September 30, 2018 and 2017, respectively, and $12.2 million and $10.8 million in natural gas processing and gathering fees under this agreement during the nine months ended September 30, 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 September 30, 2018 was approximately $45.2 million. The Company paid approximately $1.0 million and $2.5 million in transportation fees under this agreement during the three and nine months ended September 30, 2018, respectively.

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 in late 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 $132.3 million.

In April 2018, the Company entered into a short-term natural gas transportation agreement whereby the Company 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. 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 at September 30, 2018 was approximately $3.6 million. This short-term

NOTE 9 — COMMITMENTS AND CONTINGENCIES — Continued

agreement ends on September 30, 2019. The Company paid approximately $0.9 million and $1.1 million in transportation fees under this agreement during the three and nine months ended September 30, 2018, respectively.

In April 2018, the Company also entered into a 16-year, fixed-fee natural gas transportation agreement that begins on October 1, 2019, whereby the Company 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. 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 at September 30, 2018 was approximately $56.8 million.

In May 2018, the Company also entered into a 10-year, fixed-fee natural gas sales agreement whereby the Company committed to deliver residue natural gas through the counterparty's pipeline to the Texas Gulf Coast beginning on the in-service date of such pipeline, which is expected to be operational in late 2019. If the Company does not meet the volume commitment specified in the natural gas sales agreement, it may be required to pay a deficiency fee per MMBtu of natural gas deficiency. The minimum contractual obligation at September 30, 2018 was approximately $200.6 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 with subsidiaries of San Mateo. 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 September 30, 2018 was approximately $222.0 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. Since inception, San Mateo's commitments under these agreements totaled $55.3 million. The subsidiary of San Mateo paid approximately $2.0 million and $5.6 million under these agreements during the three and nine months ended September 30, 2018. As of September 30, 2018, there was no remaining obligation under these agreements.

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. Since inception, San Mateo's commitments under these agreements totaled $24.8 million. The subsidiary of San Mateo paid approximately $6.3 million and $12.8 million under these agreements during the three and nine months ended September 30, 2018. As of September 30, 2018, the remaining obligations under these agreements were $12.0 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 $32.8 million at September 30, 2018.

At September 30, 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 $44.2 million at September 30, 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 on the Company cannot be predicted with certainty, in the opinion of management, it is remote that these lawsuits will have a material adverse impact on the Company's financial condition, results of operations or cash flows.

NOTE 10 — SUPPLEMENTAL DISCLOSURES

Accrued Liabilities

The following table summarizes the Company's current accrued liabilities at September 30, 2018 and December 31, 2017 (in thousands).

	September 30, 2018	December 31, 2017
Accrued evaluated and unproved and unevaluated property costs	$ 108,420	$ 105,347
Accrued midstream property costs	16,996	14,823
Accrued lease operating expenses	18,651	12,611
Accrued interest on debt	5,407	8,345
Accrued asset retirement obligations	928	1,176
Accrued partners' share of joint interest charges	22,114	27,628
Other	6,314	4,418
Total accrued liabilities	$ 178,830	$ 174,348

Supplemental Cash Flow Information

The following table provides supplemental disclosures of cash flow information for the nine months ended September 30, 2018 and 2017 (in thousands).

	Nine Months Ended September 30,	
	2018	2017
Cash paid for interest expense, net of amounts capitalized	$ 29,773	$ 14,542
Increase in asset retirement obligations related to mineral properties	$ 1,705	$ 2,484
Increase (decrease) in asset retirement obligations related to midstream properties	$ 547	$ (138)
Increase in liabilities for oil and natural gas properties capital expenditures	$ 5,157	$ 35,940
Increase (decrease) in liabilities for midstream properties capital expenditures	$ 1,864	$ (247)
Stock-based compensation expense recognized as liability	$ (107)	$ 150
Decrease in liabilities for accrued cost to issue equity	$ —	$ (343)
Increase in liabilities for accrued cost to issue senior notes	$ 510	$ —
Transfer of inventory from oil and natural gas properties	$ 305	$ 74
Transfer of inventory to midstream and other property and equipment	$ (2,691)	$ —

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).

	Nine Months Ended September 30,	
	2018	2017
Cash	$ 45,942	$ 20,178
Restricted cash	7,066	10,744
Total cash and restricted cash	$ 53,008	$ 30,922

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, development and production 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 September 30, 2018					
Oil and natural gas revenues	$ 215,248	$ 1,034	$ —	$ —	$ 216,282
Midstream services revenues	—	24,950	—	(18,141)	6,809
Realized gain on derivatives	5,424	—	—	—	5,424
Unrealized loss on derivatives	(21,337)	—	—	—	(21,337)
Expenses(1)	128,263	10,162	19,041	(18,141)	139,325
Operating income (loss)(2)	$ 71,072	$ 15,822	$ (19,041)	$ —	$ 67,853
Total assets	$ 2,697,685	$ 391,323	$ 65,194	$ —	$ 3,154,202
Capital expenditures(3)	$ 716,751	$ 47,153	$ 312	$ —	$ 764,216

(1) Includes depletion, depreciation and amortization expenses of $67.2 million and $2.6 million for the exploration and production and midstream segments, respectively. Also includes corporate depletion, depreciation and amortization expenses of $0.6 million.

(2) Includes $7.3 million in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

(3) Includes $554.9 million attributable to land and seismic acquisition expenditures related to the exploration and production segment and $23.1 million in capital expenditures attributable to non-controlling interest in subsidiaries related to the midstream segment.

NOTE 11 — SEGMENT INFORMATION — Continued

	Exploration and Production	Midstream	Corporate	Consolidations and Eliminations	Consolidated Company
Three Months Ended September 30, 2017					
Oil and natural gas revenues	$ 134,488	$ 460	$ —	$ —	$ 134,948
Midstream services revenues	—	11,261	—	(8,043)	3,218
Realized gain on derivatives	485	—	—	—	485
Unrealized loss on derivatives	(12,372)	—	—	—	(12,372)
Expenses[(1)]	86,728	5,598	15,447	(8,043)	99,730
Operating income (loss)[(2)]	$ 35,873	$ 6,123	$ (15,447)	$ —	$ 26,549
Total assets	$ 1,590,677	$ 222,274	$ 35,586	$ —	$ 1,848,537
Capital expenditures[(3)]	$ 180,686	$ 35,008	$ 1,494	$ —	$ 217,188

(1) Includes depletion, depreciation and amortization expenses of $46.1 million and $1.3 million for the exploration and production and midstream segments, respectively. Also includes corporate depletion, depreciation and amortization expenses of $0.4 million.

(2) Includes $2.9 million in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

(3) Includes $17.2 million in capital expenditures attributable to non-controlling interest in subsidiaries related to the midstream segment.

	Exploration and Production	Midstream	Corporate	Consolidations and Eliminations	Consolidated Company
Nine Months Ended September 30, 2018					
Oil and natural gas revenues	$ 602,737	$ 4,518	$ —	$ —	$ 607,255
Midstream services revenues	—	60,658	—	(47,374)	13,284
Realized loss on derivatives	(1,322)	—	—	—	(1,322)
Unrealized loss on derivatives	(9,492)	—	—	—	(9,492)
Expenses[(1)]	359,830	26,723	55,338	(47,374)	394,517
Operating income (loss)[(2)]	$ 232,093	$ 38,453	$ (55,338)	$ —	$ 215,208
Total assets	$ 2,697,685	$ 391,323	$ 65,194	$ —	$ 3,154,202
Capital expenditures[(3)]	$ 1,105,541	$ 125,770	$ 1,570	$ —	$ 1,232,881

(1) Includes depletion, depreciation and amortization expenses of $184.4 million and $6.5 million for the exploration and production and midstream segments, respectively. Also includes corporate depletion, depreciation and amortization expenses of $1.8 million.

(2) Includes $18.2 million in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

(3) Includes $613.8 million attributable to land and seismic acquisition expenditures related to the exploration and production segment and $61.6 million in capital expenditures attributable to non-controlling interest in subsidiaries related to the midstream segment.

NOTE 11 — SEGMENT INFORMATION — Continued

	Exploration and Production	Midstream	Corporate	Consolidations and Eliminations	Consolidated Company
Nine Months Ended September 30, 2017					
Oil and natural gas revenues	$ 362,040	$ 1,519	$ —	$ —	$ 363,559
Midstream services revenues	—	32,244	—	(25,373)	6,871
Realized loss on derivatives	(1,176)	—	—	—	(1,176)
Unrealized gain on derivatives	21,449	—	—	—	21,449
Expenses(1)	233,145	16,060	47,055	(25,373)	270,887
Operating income (loss)(2)	$ 149,168	$ 17,703	$ (47,055)	$ —	$ 119,816
Total assets	$ 1,590,677	$ 222,274	$ 35,586	$ —	$ 1,848,537
Capital expenditures(3)	$ 554,642	$ 75,235	$ 4,710	$ —	$ 634,587

(1) Includes depletion, depreciation and amortization expenses of $118.2 million and $3.8 million for the exploration and production and midstream segments, respectively. Also includes corporate depletion, depreciation and amortization expenses of $1.1 million.

(2) Includes $8.0 million in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

(3) Includes $35.8 million in capital expenditures attributable to non-controlling interest in subsidiaries related to the midstream segment.

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NOTE 12 — SUBSIDIARY GUARANTORS

The 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 September 30, 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
September 30, 2018

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
ASSETS					
Intercompany receivable	$ 939,294	$ 26,382	$ —	$ (965,676)	$ —
Third-party current assets	827	23,159	201,446	—	225,432
Net property and equipment	—	343,371	2,578,603	—	2,921,974
Investment in subsidiaries	1,346,446	—	183,297	(1,529,743)	—
Third-party long-term assets	6,425	—	3,305	(2,934)	6,796
Total assets	$ 2,292,992	$ 392,912	$ 2,966,651	$ (2,498,353)	$ 3,154,202
LIABILITIES AND EQUITY					
Intercompany payable	$ —	$ —	$ 965,676	$ (965,676)	$ —
Third-party current liabilities	5,763	30,335	290,909	(256)	326,751
Senior unsecured notes payable	740,063	—	—	—	740,063
Other third-party long-term liabilities	—	4,003	363,620	(2,678)	364,945
Total equity attributable to Matador Resources Company	1,547,166	183,297	1,346,446	(1,529,743)	1,547,166
Non-controlling interest in subsidiaries	—	175,277	—	—	175,277
Total liabilities and equity	$ 2,292,992	$ 392,912	$ 2,966,651	$ (2,498,353)	$ 3,154,202

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 September 30, 2018

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Total revenues	$ —	$ 25,640	$ 199,386	$ (17,848)	$ 207,178
Total expenses	1,184	10,708	145,281	(17,848)	139,325
Operating (loss) income	(1,184)	14,932	54,105	—	67,853
Net loss on asset sales and inventory impairment	—	—	(196)	—	(196)
Interest expense	(10,340)	—	—	—	(10,340)

Prepayment premium on extinguishment of debt	(31,226)	—	—	—	(31,226)
Other (expense) income	(6)	8	(978)	—	(976)
Earnings in subsidiaries	60,550	—	7,619	(68,169)	—
Income before income taxes	17,794	14,940	60,550	(68,169)	25,115
Net income attributable to non-controlling interest in subsidiaries	—	(7,321)	—	—	(7,321)
Net income attributable to Matador Resources Company shareholders	$ 17,794	$ 7,619	$ 60,550	$ (68,169)	$ 17,794

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

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Total revenues	$ —	$ 11,242	$ 122,675	$ (7,638)	$ 126,279
Total expenses	1,175	5,253	100,940	(7,638)	99,730
Operating (loss) income	(1,175)	5,989	21,735	—	26,549
Net gain on asset sales and inventory impairment	—	—	16	—	16
Interest expense	(8,550)	—	—	—	(8,550)
Other income	27	11	(74)	—	(36)
Earnings in subsidiaries	24,674	—	2,997	(27,671)	—
Income before income taxes	14,976	6,000	24,674	(27,671)	17,979
Total income tax (benefit) provision	(63)	63	—	—	—
Net income attributable to non-controlling interest in subsidiaries	—	(2,940)	—	—	(2,940)
Net income attributable to Matador Resources Company shareholders	$ 15,039	$ 2,997	$ 24,674	$ (27,671)	$ 15,039

Condensed Consolidating Statement of Operations
For the Nine Months Ended September 30, 2018

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Total revenues	$ —	$ 64,190	$ 592,085	$ (46,550)	$ 609,725
Total expenses	3,596	27,102	410,369	(46,550)	394,517
Operating (loss) income	(3,596)	37,088	181,716	—	215,208
Net loss on asset sales and inventory impairment	—	—	(196)	—	(196)
Interest expense	(26,835)	—	—	—	(26,835)
Other (expense) income	—	19	(1,294)	—	(1,275)
Prepayment premium on extinguishment of debt	(31,226)	—	—	—	(31,226)
Earnings in subsidiaries	199,151	—	18,925	(218,076)	—
Income before income taxes	137,494	37,107	199,151	(218,076)	155,676
Net income attributable to non-controlling interest in subsidiaries	—	(18,182)	—	—	(18,182)
Net income attributable to Matador Resources Company shareholders	$ 137,494	$ 18,925	$ 199,151	$ (218,076)	$ 137,494

Condensed Consolidating Statement of Operations
For the Nine Months Ended September 30, 2017

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Total revenues	$ —	$ 32,179	$ 382,520	$ (23,996)	$ 390,703
Total expenses	4,021	13,935	276,927	(23,996)	270,887
Operating (loss) income	(4,021)	18,244	105,593	—	119,816
Net gain on asset sales and inventory impairment	—	—	23	—	23
Interest expense	(26,229)	—	—	—	(26,229)
Other income	27	37	1,892	—	1,956
Earnings in subsidiaries	117,574	—	10,066	(127,640)	—
Income before income taxes	87,351	18,281	117,574	(127,640)	95,566
Total income tax (benefit) provision	(181)	181	—	—	—
Net income attributable to non-controlling interest in subsidiaries	—	(8,034)	—	—	(8,034)
Net income attributable to Matador Resources Company shareholders	$ 87,532	$ 10,066	$ 117,574	$ (127,640)	$ 87,532

Condensed Consolidating Statement of Cash Flows
For the Nine Months Ended September 30, 2018

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Net cash (used in) provided by operating activities	$ (361,016)	$ 12,318	$ 768,016	$ —	$ 419,318
Net cash used in investing activities	—	(120,836)	(1,152,987)	53,295	(1,220,528)
Net cash provided by financing activities	361,155	109,400	334,476	(53,295)	751,736
Increase (decrease) in cash and restricted cash	139	882	(50,495)	—	(49,474)
Cash and restricted cash at beginning of period	286	5,663	96,533	—	102,482

Cash and restricted cash at end of period	$ 425	$ 6,545	$ 46,038	$ —	$ 53,008

Condensed Consolidating Statement of Cash Flows
For the Nine Months Ended September 30, 2017

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Net cash (used in) provided by operating activities	$ (99,546)	$ 24,075	$ 297,987	$ —	$ 222,516
Net cash provided by (used in) investing activities	33	(75,749)	(387,257)	(133,880)	(596,853)
Net cash provided by (used in) financing activities	—	58,732	(1,495)	133,880	191,117
(Decrease) increase in cash and restricted cash	(99,513)	7,058	(90,765)	—	(183,220)
Cash and restricted cash at beginning of period	99,795	2,900	111,447	—	214,142
Cash and restricted cash at end of period	$ 282	$ 9,958	$ 20,682	$ —	$ 30,922

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our interim unaudited condensed consolidated financial statements and related notes thereto contained herein and 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 similar words, 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;

- our ability and the ability of our midstream joint venture to construct and operate midstream facilities, including the 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.

Third Quarter and Year-to-Date Highlights

For the three months ended September 30, 2018, our total oil equivalent production was 5.0 million BOE, and our average daily oil equivalent production was 54,625 BOE per day, of which 32,317 Bbl per day, or 59%, was oil and 133.8 MMcf per day, or 41%, was natural gas. Our oil production of 3.0 million Bbl for the three months ended September 30, 2018 increased 37% year-over-year from 2.2 million Bbl for the three months ended September 30, 2017. Our natural gas production of 12.3 Bcf for the three months ended September 30, 2018 increased 21% year-over-year from 10.2 Bcf for the three months ended September 30, 2017. For the nine months ended September 30, 2018, our total oil equivalent production was 13.9 million BOE, and our average daily oil equivalent production was 50,979 BOE per day, of which 29,529 Bbl per day, or 58%, was oil and 128.7 MMcf per day, or 42%, was natural gas. Our oil production of 8.1 million Bbl for the nine months ended September 30, 2018 increased 44% year-over-year from 5.6 million Bbl for the nine months ended September 30, 2017. Our natural gas production of 35.1 Bcf for the nine months ended September 30, 2018 increased 27% year-over-year from 27.6 Bcf for the nine months ended September 30, 2017.

For the third quarter of 2018, we reported net income attributable to Matador Resources Company shareholders of approximately $17.8 million, or $0.15 per diluted common share, on a GAAP basis, as compared to net income attributable to Matador Resources Company shareholders of $15.0 million, or $0.15 per diluted common share, for the third quarter of 2017. For the third quarter of 2018, our Adjusted EBITDA attributable to Matador Resources Company shareholders (“Adjusted EBITDA”), a non-GAAP financial measure, was $155.4 million, as compared to Adjusted EBITDA of $84.8 million during the third quarter of 2017. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income 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 third quarter of 2018, see "— Results of Operations" below.

For the nine months ended September 30, 2018, we reported net income attributable to Matador Resources Company shareholders of approximately $137.5 million, or $1.21 per diluted common share, on a GAAP basis, as compared to net income attributable to Matador Resources Company shareholders of $87.5 million, or $0.87 per diluted common share, for the nine months ended September 30, 2017. For the nine months ended September 30, 2018, our Adjusted EBITDA, a non-GAAP financial measure, was $410.0 million, as compared to Adjusted EBITDA of $227.4 million during the nine months ended September 30, 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 nine months ended September 30, 2018, see "— Results of Operations" below.

Operations Update

During the third 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 through September 30, 2018. We expect to operate those six rigs in the Delaware Basin through the remainder of 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. We have continued to build significant optionality into our drilling program. Three of our rigs operate on longer-term contracts with remaining average terms between 12 and 15 months. The other three rigs are on short-term contracts with remaining obligations of six months or less. This affords us the ability to modify our drilling program as management may determine necessary based on changing commodity prices and other factors.

Effective October 1, 2018, we added a seventh operated drilling rig to our drilling program on a short-term contract. This seventh drilling rig was deployed initially in South Texas to drill up to ten wells, primarily in the Eagle Ford shale. This rig is expected to operate in South Texas throughout the fourth quarter of 2018 and into early 2019. At that time, subject to commodity prices and other economic circumstances, we anticipate moving this rig to the Delaware Basin, most likely to either the Arrowhead or Antelope Ridge asset area. We then expect to operate this seventh rig in the Delaware Basin throughout the remainder of 2019.

By initially deploying this seventh rig in South Texas over the next several months, we will be able to add to our oil production in South Texas during a time when our realized oil price in the Gulf Coast region is expected to be significantly higher than our realized oil price in the Delaware Basin. Further, given the results of the five-well Eagle Ford program we drilled in 2017, we anticipate strong economic returns from this drilling program. In addition, drilling these wells in South Texas provides us with the opportunity to test and establish the prospectivity of new formations, such as the Austin Chalk, which we have not previously tested on our South Texas leasehold. This short drilling program should also enable us to satisfy several near-term lease expiration obligations. The first few wells in this South Texas drilling program are expected to be completed and placed on production late in the fourth quarter of 2018. As a result, we expect the initial production from these wells should have a limited impact on our fourth quarter and full-year 2018 production estimates.

During the third 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. We did participate in the drilling and completion of two gross (0.3 net) non-operated Eagle Ford shale wells that were turned to sales in the third quarter of 2018.

We completed and turned to sales a total of 36 gross (16.6 net) wells in the Delaware Basin during the third quarter of 2018, including 19 gross (15.0 net) operated horizontal wells and 17 gross (1.6 net) non-operated horizontal wells. During the third quarter of 2018, we began producing oil and natural gas from a total of six gross (2.7 net) wells in the Antelope Ridge asset area, including three gross (2.7 net) operated and three gross (less than 0.1 net) non-operated wells. The three gross operated wells included two Wolfcamp A-Lower and one Third Bone Spring completion. In the Rustler Breaks asset area, we began producing oil and natural gas from a total of 26 gross (11.7 net) wells during the third quarter of 2018, including 13 gross (10.5 net) operated and 13 gross (1.2 net) non-operated wells. Of the 13 gross operated wells in the Rustler Breaks asset area, eight were Wolfcamp A-XY completions, two were Wolfcamp A-Lower completions, one was a Wolfcamp B-Blair completion and two were Second Bone Spring completions. 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 third quarter of 2018, including one Wolfcamp A-XY completion and one Wolfcamp B completion. Finally, in the Arrowhead asset area, we began producing oil and natural gas from one gross (0.8 net) operated well, a Wolfcamp A-XY completion, during the third 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 third quarter of 2018 was 47,831 BOE per day, consisting of 29,931 Bbl of oil per day and 107.4 MMcf of natural gas per day, a 56% increase from production of 30,707 BOE per day, consisting of 18,689 Bbl of oil per day and 72.1 MMcf of natural gas per day, in the third quarter of 2017. The Delaware Basin contributed approximately 93% of our daily oil production and approximately 80% of our daily natural gas production in the third quarter of 2018, as compared to approximately 79% of our daily oil production and approximately 65% of our daily natural gas production in the third quarter of 2017.

Recent Acreage Acquisitions

On September 12, 2018, we announced the successful acquisition of 8,400 gross (8,400 net) leasehold acres in Lea and Eddy Counties, New Mexico for approximately $387 million, or a weighted average cost of approximately $46,000 per net acre, in the Bureau of Land Management New Mexico Oil and Gas Lease Sale on September 5 and 6, 2018 (the "BLM Acquisition"). The acquired leasehold acreage includes approximately 2,800 gross/net acres in the Stateline area, 4,800 gross/net acres in the Antelope Ridge asset area, 400 gross/net acres in the Arrowhead asset area and 400 gross/net acres in the Twin Lakes asset area.

We completed the BLM Acquisition on September 20, 2018, and we expect the leases will be issued to us in the fourth quarter of 2018. We financed the BLM Acquisition using cash on hand and borrowings under our revolving credit facility (the "Credit Agreement"). At September 30, 2018, we had $325.0 million in borrowings outstanding under the Credit Agreement and approximately $3.0 million in outstanding letters of credit issued pursuant to the Credit Agreement.

In addition to the BLM Acquisition, during the third quarter of 2018, we acquired approximately 12,600 net leasehold and mineral acres in and around our existing acreage positions in the Delaware Basin, including approximately 2,600 net mineral acres. Including the BLM Acquisition, we have added approximately 27,200 net leasehold and mineral acres in the Delaware Basin from January 1 through October 31, 2018, bringing our total Delaware Basin leasehold and mineral position to approximately 222,200 gross (131,200 net) acres at October 31, 2018.

Capital Market Transactions

As of June 30, 2018, we had $575.0 million aggregate principal amount of outstanding 6.875% senior notes due 2023 (the "2023 Notes"). On August 21, 2018, we issued $750.0 million of 5.875% senior unsecured notes due 2026 (the "Original 2026 Notes") in a private placement (the "2026 Notes Offering"). The Original 2026 Notes were issued at par value, and we received net proceeds of approximately $740.0 million, after deducting the initials purchasers' discounts and estimated offering expenses. In conjunction with the 2026 Notes Offering, in August and September 2018, respectively, we completed a tender offer to purchase for cash and subsequent redemption of all of our $575.0 million aggregate principal amount of 2023 Notes (the "2023 Notes Tender Offer and Redemption"). We used a portion of the net proceeds from the 2026 Notes Offering to fund the 2023 Notes Tender Offer and Redemption.

On October 4, 2018, we issued an additional $300.0 million of 5.875% senior unsecured notes due 2026 (the "Additional 2026 Notes" and, collectively with the Original 2026 Notes, the "Notes"). The Additional 2026 Notes were issued pursuant to, and are governed by, the same indenture governing the Original 2026 Notes (the "Indenture"). The Additional 2026 Notes were issued at 100.5% of par, plus accrued interest from August 21, 2018. We received net proceeds from this offering of approximately $297.6 million, after deducting the initial purchasers' discounts and estimated offering expenses but excluding accrued interest from August 21, 2018 paid by the initial purchasers of the Additional 2026 Notes. The proceeds from this offering were used to repay a portion of the outstanding borrowings under the Credit Agreement, which were incurred in connection with the BLM Acquisition. The Notes will mature September 15, 2026, and interest is payable on the Notes semi-annually in arrears on each March 15 and September 15.

2018 Capital Expenditure Budget

On August 1, 2018, we adjusted our anticipated 2018 capital expenditures for drilling and completions (including equipping wells for production) from $530 to $570 million to $620 to $650 million and our anticipated midstream capital expenditures remained $70 to $90 million, which primarily represents our 51% share of San Mateo's 2018 estimated capital expenditures. With the addition of the seventh drilling rig deployed to South Texas on October 1, 2018, we increased our anticipated 2018 capital expenditures for drilling and completions (including equipping wells for production) by approximately 4%, or $25 to $30 million, to $645 to $680 million. We have allocated substantially all of our estimated 2018 capital expenditures to the further delineation and development of our growing leasehold position and midstream assets in the Delaware Basin, with the exception of the South Texas drilling program beginning in the fourth quarter of 2018 and amounts allocated to limited non-operated activities in the Eagle Ford and Haynesville shales. For the remainder of 2018, our Delaware Basin drilling program will continue to focus on the development of the Wolf and Rustler Breaks asset areas and the further delineation and development of the Jackson Trust, Ranger/Arrowhead, Antelope Ridge and Twin Lakes asset areas, although we may also continue to delineate previously untested zones in the Wolf and Rustler Breaks asset areas.

Natural Gas Gathering and Processing Agreement

In October 2018, a subsidiary of San Mateo entered into a long-term agreement with a producer in Eddy County, New Mexico relating to the gathering and processing of such producer's natural gas production. As a result of this agreement, along with prior natural gas gathering and processing agreements entered into by San Mateo with the Company and other customers, San Mateo has now entered into contracts to provide firm gathering and processing services for over 200 million cubic feet of natural gas per day, or over 80% of the designed inlet capacity of 260 million cubic feet of natural gas per day, at its Black River cryogenic natural gas processing plant in the Rustler Breaks asset area in Eddy County, New Mexico (the "Black River Processing Plant").

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 Accounting Standards Update 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.

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Results of Operations

Revenues

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

	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Operating Data:				
Revenues (in thousands):[1]				
Oil	$ 169,913	$ 100,150	$ 484,343	$ 265,107
Natural gas	46,369	34,798	122,912	98,452
Total oil and natural gas revenues	216,282	134,948	607,255	363,559
Third-party midstream services revenues	6,809	3,218	13,284	6,871
Realized gain (loss) on derivatives	5,424	485	(1,322)	(1,176)
Unrealized (loss) gain on derivatives	(21,337)	(12,372)	(9,492)	21,449
Total revenues	$ 207,178	$ 126,279	$ 609,725	$ 390,703
Net Production Volumes:[1]				
Oil (MBbl)[2]	2,973	2,166	8,061	5,582
Natural gas (Bcf)[3]	12.3	10.2	35.1	27.6
Total oil equivalent (MBOE)[4]	5,025	3,860	13,917	10,190
Average daily production (BOE/d)[5]	54,625	41,954	50,979	37,325
Average Sales Prices:				
Oil, without realized derivatives (per Bbl)	$ 57.15	$ 46.25	$ 60.08	$ 47.49
Oil, with realized derivatives (per Bbl)	$ 58.97	$ 46.47	$ 59.91	$ 47.39
Natural gas, without realized derivatives (per Mcf)	$ 3.77	$ 3.42	$ 3.50	$ 3.56
Natural gas, with realized derivatives (per Mcf)	$ 3.77	$ 3.42	$ 3.50	$ 3.54

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

(2) One thousand barrels of oil.

(3) One billion cubic feet of natural gas.

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

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

Three Months Ended September 30, 2018 as Compared to Three Months Ended September 30, 2017

Oil and natural gas revenues. Our oil and natural gas revenues increased $81.3 million to $216.3 million, or 60%, for the three months ended September 30, 2018, as compared to $134.9 million for the three months ended September 30, 2017. Our oil revenues increased $69.8 million, or 70%, to $169.9 million for the three months ended September 30, 2018, as compared to $100.2 million for the three months ended September 30, 2017. The increase in oil revenues resulted from (i) a higher weighted average oil price realized for the three months ended September 30, 2018 of $57.15 per Bbl, as compared to $46.25 per Bbl realized for the three months ended September 30, 2017, and (ii) the 37% increase in our oil production to 3.0 million Bbl of oil for the three months ended September 30, 2018, or 32,317 Bbl of oil per day, as compared to 2.2 million Bbl of oil, or 23,538 Bbl of oil per day, for the three months ended September 30, 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 $11.6 million, or 33%, to $46.4 million for the three months ended September 30, 2018, as compared to $34.8 million for the three months ended September 30, 2017. The increase in natural gas revenues resulted from the 21% increase in our natural gas production to 12.3 Bcf for the three months ended September 30, 2018, as compared to 10.2 Bcf for the three months ended September 30, 2017, and from the 10% increase in our realized natural gas prices between the two periods. The increase in natural gas production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin.

Third-party midstream services revenues. Our third-party midstream services revenues increased $3.6 million to $6.8 million, or 112%, for the three months ended September 30, 2018, as compared to $3.2 million for the three months ended September 30, 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 an increase in our third-party salt water gathering and disposal revenues to approximately $3.3 million for the three months ended September 30, 2018, as compared to approximately $0.4 million for the three months ended September 30, 2017.

Realized gain on derivatives. Our realized net gain on derivatives was $5.4 million for the three months ended September 30, 2018, as compared to a realized net gain of $0.5 million for the three months ended September 30, 2017. We realized a net loss of $10.2 million related to our oil costless collar contracts for the three months ended September 30, 2018, resulting from oil prices that were above the short call/ceiling prices of certain of our oil costless collar contracts. We realized a net gain of $15.6 million related to our oil basis swap contracts for the three months ended September 30, 2018, resulting from oil basis prices lower than the swap prices of certain of our oil basis swap contracts. We realized a net gain of $0.5 million from our oil derivative contracts for the three months ended September 30, 2017, resulting from oil prices that were below the floor prices of certain of our oil costless collar contracts. We realized an average gain on our oil derivatives contracts of approximately $1.82 per Bbl produced during the three months ended September 30, 2018, as compared to an average gain of approximately $0.22 per Bbl produced during the three months ended September 30, 2017. Our total oil volumes hedged for the three months ended September 30, 2018 represented 47% of our total oil production, as compared to 57% of our total oil production for the three months ended September 30, 2017. Our total natural gas volumes hedged for the three months ended September 30, 2018 represented 34% of our total natural gas production, as compared to 62% of our total natural gas production for the three months ended September 30, 2017.

Unrealized loss on derivatives. Our unrealized net loss on derivatives was $21.3 million for the three months ended September 30, 2018, as compared to an unrealized net loss of $12.4 million for the three months ended September 30, 2017. During the three months ended September 30, 2018, the net fair value of our open oil and natural gas derivative contracts decreased to a net liability of $24.7 million from a net liability of $3.4 million at June 30, 2018, resulting in an unrealized loss on derivatives of $21.3 million for the three months ended September 30, 2018. During the three months ended September 30, 2017, the net fair value of our open oil and natural gas derivative contracts decreased to a net liability of approximately $3.5 million from a net asset of $8.9 million at June 30, 2017, resulting in an unrealized loss on derivatives of $12.4 million for the three months ended September 30, 2017.

Nine Months Ended September 30, 2018 as Compared to Nine Months Ended September 30, 2017

Oil and natural gas revenues. Our oil and natural gas revenues increased $243.7 million to $607.3 million, or 67%, for the nine months ended September 30, 2018, as compared to $363.6 million for the nine months ended September 30, 2017. Our oil revenues increased $219.2 million, or 83%, to $484.3 million for the nine months ended September 30, 2018, as compared to $265.1 million for the nine months ended September 30, 2017. The increase in oil revenues resulted from (i) a higher weighted average oil price realized for the nine months ended September 30, 2018 of $60.08 per Bbl, as compared to $47.49 per Bbl realized for the nine months ended September 30, 2017, and (ii) the 44% increase in our oil production to 8.1 million Bbl of oil for the nine months ended September 30, 2018, or 29,529 Bbl of oil per day, as compared to 5.6 million Bbl of oil, or 20,447 Bbl of oil per day, for the nine months ended September 30, 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 $24.5 million, or 25%, to $122.9 million for the nine months ended September 30, 2018, as compared to $98.5 million for the nine months ended September 30, 2017. The increase in natural gas revenues resulted from the 27% increase in our natural gas production to 35.1 Bcf for the nine months ended September 30, 2018, as compared to 27.6 Bcf for the nine months ended September 30, 2017, which was partially offset by a slightly lower weighted average natural gas price realized for the nine months ended September 30, 2018 of $3.50 per Mcf, as compared to $3.56 per Mcf realized for the nine months ended September 30, 2017. The increase in natural gas production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin.

Third-party midstream services revenues. Our third-party midstream services revenues increased $6.4 million to $13.3 million, or 93%, for the nine months ended September 30, 2018, as compared to $6.9 million for the nine months ended September 30, 2017. This increase was primarily attributable to (i) an increase in our third-party salt water gathering and disposal revenues to approximately $6.3 million for the nine months ended September 30, 2018, as compared to approximately $1.1 million for the nine months ended September 30, 2017, and (ii) an increase in natural gas gathering and processing revenues to approximately $6.8 million for the nine months ended September 30, 2018, as compared to $5.6 million for the nine months ended September 30, 2017, due to increased natural gas volumes being gathered and/or processed in our Rustler Breaks and Wolf asset areas.

Realized loss on derivatives. Our realized net loss on derivatives was $1.3 million for the nine months ended September 30, 2018, as compared to a realized net loss of $1.2 million for the nine months ended September 30, 2017. We realized a net loss of $21.6 million related to our oil costless collar contracts for the nine months ended September 30, 2018, resulting from oil prices that were above the short call/ceiling prices of certain of our oil costless collar contracts. We realized a net gain of $20.3 million related to our oil basis swap contracts for the nine months ended September 30, 2018, resulting from oil basis prices lower than the swap prices of certain of our oil basis swap contracts. We realized net losses of $0.6 million from both our oil and natural gas derivative contracts for the nine months ended September 30, 2017, resulting from oil and natural gas prices that were above the ceiling prices of certain of our oil and natural gas costless collar contracts. We realized an average loss on our oil derivatives of approximately $0.17 per Bbl produced during the nine months ended September 30, 2018, as compared to an average loss of $0.10 per Bbl produced during the nine months ended September 30, 2017. Our total oil volumes hedged for the nine months ended September 30, 2018 represented 50% of our total oil production, as compared to 61% of our total oil production for the nine months ended September 30, 2017. Our total natural gas volumes hedged for the nine months ended September 30, 2018 represented 36% of our total natural gas production, as compared to 64% of our total natural gas production for the nine months ended September 30, 2017.

Unrealized (loss) gain on derivatives. Our unrealized net loss on derivatives was $9.5 million for the nine months ended September 30, 2018, as compared to an unrealized net gain of $21.4 million for the nine months ended September 30, 2017. During the period from December 31, 2017 through September 30, 2018, the aggregate net fair value of our open oil and natural gas derivative contracts decreased to a net liability of approximately $24.7 million from a net liability of approximately $15.2 million, resulting in an unrealized loss on derivatives of approximately $9.5 million for the nine months ended September 30, 2018. During the period from December 31, 2016 through September 30, 2017, the aggregate net fair value of our open oil and natural gas derivative contracts increased from a net liability of approximately $25.0 million to a net liability of approximately $3.5 million, resulting in an unrealized gain on derivatives of approximately $21.4 million for the nine months ended September 30, 2017.

Expenses

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In thousands, except expenses per BOE)	**2018**	**2017**	**2018**	**2017**
Expenses:				
Production taxes, transportation and processing	$ 20,215	$ 15,666	$ 58,116	$ 40,348
Lease operating	22,531	16,689	69,685	48,486
Plant and other midstream services operating	7,291	3,096	17,187	8,379
Depletion, depreciation and amortization	70,457	47,800	192,664	123,066
Accretion of asset retirement obligations	387	323	1,126	937
General and administrative	18,444	16,156	55,739	49,671
Total expenses	139,325	99,730	394,517	270,887
Operating income	67,853	26,549	215,208	119,816
Other income (expense):				
Net (loss) gain on asset sales and inventory impairment	(196)	16	(196)	23
Interest expense	(10,340)	(8,550)	(26,835)	(26,229)
Prepayment premium on extinguishment of debt	(31,226)	—	(31,226)	—
Other (expense) income	(976)	(36)	(1,275)	1,956
Total other expense	(42,738)	(8,570)	(59,532)	(24,250)
Net income	25,115	17,979	155,676	95,566
Net income attributable to non-controlling interest in subsidiaries	(7,321)	(2,940)	(18,182)	(8,034)
Net income attributable to Matador Resources Company shareholders	$ 17,794	$ 15,039	$ 137,494	$ 87,532
Expenses per BOE:				
Production taxes, transportation and processing	$ 4.02	$ 4.06	$ 4.18	$ 3.96
Lease operating	$ 4.48	$ 4.32	$ 5.01	$ 4.76
Plant and other midstream services operating	$ 1.45	$ 0.80	$ 1.23	$ 0.82
Depletion, depreciation and amortization	$ 14.02	$ 12.38	$ 13.84	$ 12.08
General and administrative	$ 3.67	$ 4.19	$ 4.00	$ 4.87

Three Months Ended September 30, 2018 as Compared to Three Months Ended September 30, 2017

Production taxes, transportation and processing. Our production taxes, transportation and processing expenses increased $4.5 million to $20.2 million, or 29%, for the three months ended September 30, 2018, as compared to $15.7 million for the three months ended September 30, 2017. On a unit-of-production basis, our production taxes, transportation and processing expenses decreased 1% to $4.02 per BOE for the three months ended September 30, 2018, as compared to $4.06 per BOE for the three months ended September 30, 2017. The increase in production taxes, transportation and processing expenses was primarily attributable to the $7.9 million increase in our production taxes to $16.0 million for the three months ended September 30, 2018, as compared to $8.1 million for the three months ended September 30, 2017, principally due to the $81.3 million increase in oil and natural gas revenues for the three months ended September 30, 2018, as compared to the three months ended September 30, 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 $5.8 million to $22.5 million, or 35%, for the three months ended September 30, 2018, as compared to $16.7 million for the three months ended September 30, 2017. On a unit-of-production basis, our lease operating expenses increased 4% to $4.48 per BOE for the three months ended September 30, 2018, as compared to $4.32 per BOE for the three months ended September 30, 2017. The increase in lease operating expenses for the three months ended September 30, 2018, as compared to the three months ended September 30, 2017, was primarily attributable to an increase in costs of services and equipment related to the increased number of wells at September 30, 2018, as compared to September 30, 2017.

Plant and other midstream services operating. Our plant and other midstream services operating expenses increased $4.2 million to $7.3 million, or an increase of 135%, for the three months ended September 30, 2018, as compared to $3.1 million for the three months ended September 30, 2017. This increase was primarily attributable to (i) increased expenses associated with our expanded commercial salt water disposal operations to $3.7 million for the three months ended September 30, 2018, as compared to $1.6 million for the three months ended September 30, 2017, and (ii) increased expenses associated with the Black River Processing Plant, which was expanded in the first quarter of 2018, to $1.7 million for the three months ended September 30, 2018, as compared to $1.0 million for the three months ended September 30, 2017.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased $22.7 million to $70.5 million, or 47%, for the three months ended September 30, 2018, as compared to $47.8 million for the three months ended September 30, 2017. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased 13% to $14.02 per BOE for the three months ended September 30, 2018, as compared to $12.38 per BOE for the three months ended September 30, 2017. The increase in our total depletion, depreciation and amortization expenses was primarily attributable to (i) increased well costs year-over-year in response to increased oil prices over the past year and (ii) the 30% increase in our total oil equivalent production to 5.0 million BOE for the three months ended September 30, 2018, as compared to 3.9 million BOE for the three months ended September 30, 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 September 30, 2018, as compared to September 30, 2017, 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 $2.6 million for the three months ended September 30, 2018, as compared to $1.3 million for the three months ended September 30, 2017.

General and administrative. Our general and administrative expenses increased $2.3 million to $18.4 million, or 14%, for the three months ended September 30, 2018, as compared to $16.2 million for the three months ended September 30, 2017. The increase in our general and administrative expenses was primarily attributable to increased payroll and related expenses of $5.6 million, including approximately $3.5 million of non-cash stock-based compensation. These increases were partially offset by the $2.4 million increase in capitalized general and administrative expenses for the three months ended September 30, 2018, as compared to the three months ended September 30, 2017. As a result of the 30% increase in oil and natural gas production for the three months ended September 30, 2018, as compared to the three months ended September 30, 2017, our general and administrative expenses decreased 12% on a unit-of-production basis to $3.67 per BOE for the three months ended September 30, 2018, as compared to $4.19 per BOE for the three months ended September 30, 2017.

Interest expense. For the three months ended September 30, 2018, we incurred total interest expense of approximately $12.1 million. We capitalized approximately $1.7 million of our interest expense on certain qualifying projects for the three months ended September 30, 2018 and expensed the remaining $10.3 million to operations. For the three months ended September 30, 2017, we incurred total interest expense of approximately $10.6 million. We capitalized approximately $2.1 million of our interest expense on certain qualifying projects for the three months ended September 30, 2017 and expensed the remaining $8.6 million to operations.

Prepayment premium on extinguishment of debt. Our prepayment premium on the extinguishment of debt for the three months ended September 30, 2018 was $31.2 million due to the 2023 Notes Tender Offer and Redemption, including total payments of $30.4 million to holders of the 2023 Notes as a result of the tender premium and the required 105.156% redemption price payable pursuant to the 2023 Notes indenture.

Total income tax benefit. Our deferred tax assets exceeded our deferred tax liabilities at September 30, 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 September 30, 2018 due to uncertainties regarding the future realization of our deferred tax assets. Should we continue to generate net income, we anticipate the reversal of a portion of the deferred tax asset valuation allowance in a future period.

Nine Months Ended September 30, 2018 as Compared to Nine Months Ended September 30, 2017

Production taxes, transportation and processing. Our production taxes, transportation and processing expenses increased $17.8 million to $58.1 million, or 44%, for the nine months ended September 30, 2018, as compared to $40.3 million for the nine months ended September 30, 2017. On a unit-of-production basis, our production taxes, transportation and processing expenses increased 6% to $4.18 per BOE for the nine months ended September 30, 2018, as compared to $3.96 per BOE for the nine months ended September 30, 2017. The increase in production taxes, transportation and processing expenses was primarily attributable to the $22.0 million increase in our production taxes to $44.2 million for the nine months ended September 30, 2018, as compared to $22.2 million for the nine months ended September 30, 2017, principally due to the $243.7 million increase in oil and natural gas revenues for the nine months ended September 30, 2018, as compared to the nine months ended September 30, 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 $21.2 million to $69.7 million, or 44%, for the nine months ended September 30, 2018, as compared to $48.5 million for the nine months ended September 30, 2017. Our lease operating expenses on a unit-of production basis increased 5% to $5.01 per BOE for the nine months ended September 30, 2018, as compared to $4.76

per BOE for the nine months ended September 30, 2017. The increase in lease operating expenses for the nine months ended September 30, 2018, as compared to the nine months ended September 30, 2017, was primarily attributable to an increase in costs of services and equipment, including salt water disposal costs in asset areas other than Wolf and Rustler Breaks (which are serviced by San Mateo), at September 30, 2018, as compared to September 30, 2017.

Plant and other midstream services operating. Our plant and other midstream services operating expenses increased $8.8 million to $17.2 million, or 105%, for the nine months ended September 30, 2018, as compared to $8.4 million for the nine months ended September 30, 2017. This increase was primarily attributable to (i) increased expenses associated with our expanded commercial salt water disposal operations to $8.8 million for the nine months ended September 30, 2018, as compared to $4.7 million for the nine months ended September 30, 2017, and (ii) increased expenses associated with the Black River Processing Plant, which was expanded in the first quarter of 2018, to $5.3 million for the nine months ended September 30, 2018, as compared to $2.8 million for the nine months ended September 30, 2017.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased $69.6 million to $192.7 million, or 57%, for the nine months ended September 30, 2018, as compared to $123.1 million for the nine months ended September 30, 2017. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased 15% to $13.84 per BOE for the nine months ended September 30, 2018, as compared to $12.08 per BOE for the nine months ended September 30, 2017. The increase in our total depletion, depreciation and amortization expenses was primarily attributable to (i) increased well costs in response to increased oil prices over the past year and (ii) the 37% increase in our total oil equivalent production to 13.9 million BOE for the nine months ended September 30, 2018, as compared to 10.2 million BOE for the nine months ended September 30, 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 September 30, 2018, as compared to September 30, 2017, 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 $6.5 million for the nine months ended September 30, 2018, as compared to $3.8 million for the nine months ended September 30, 2017.

General and administrative. Our general and administrative expenses increased $6.1 million to $55.7 million, or 12%, for the nine months ended September 30, 2018, as compared to $49.7 million for the nine months ended September 30, 2017. The increase in our general and administrative expenses was partially attributable to increased payroll and related expenses of approximately $9.4 million associated with additional employees joining the Company to support our increased land, geoscience, drilling, completion, production, midstream, accounting and administration functions as a result of our continued growth. These increases were partially offset by the $5.7 million increase in capitalized general and administrative expenses for the nine months ended September 30, 2018, as compared to the nine months ended September 30, 2017. As a result of the 37% increase in oil and natural gas production for the nine months ended September 30, 2018, as compared to the nine months ended September 30, 2017, our general and administrative expenses decreased 18% on a unit-of-production basis to $4.00 per BOE for the nine months ended September 30, 2018, as compared to $4.87 per BOE for the nine months ended September 30, 2017.

Interest expense. For the nine months ended September 30, 2018, we incurred total interest expense of approximately $33.0 million. We capitalized approximately $6.2 million of our interest expense on certain qualifying projects for the nine months ended September 30, 2018 and expensed the remaining $26.8 million to operations. For the nine months ended September 30, 2017, we incurred total interest expense of approximately $31.5 million. We capitalized approximately $5.2 million of our interest expense on certain qualifying projects for the nine months ended September 30, 2017 and expensed the remaining $26.2 million to operations.

Prepayment premium on extinguishment of debt. Our prepayment premium on the extinguishment of debt for the nine months ended September 30, 2018 was $31.2 million due to the 2023 Notes Tender Offer and Redemption, including total payments of $30.4 million to holders of the 2023 Notes as a result of the tender premium and the required 105.156% redemption price payable pursuant to the 2023 Notes indenture.

Total income tax benefit. Our deferred tax assets exceeded our deferred tax liabilities at September 30, 2018 due to the deferred tax amounts generated by the full-cost ceiling impairment charges recorded in prior periods. As a result, we established a valuation allowance against the deferred tax assets beginning in the third quarter of 2015. We retained a full valuation allowance at September 30, 2018 due to uncertainties regarding the future realization of our deferred tax assets. Should we continue to generate net income, we anticipate the reversal of a portion of the deferred tax asset valuation allowance in a future period.

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 for the remainder of 2018 and for 2019 through a combination of cash on hand, operating cash flows and borrowings under 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.

As of June 30, 2018, we had $575.0 million of outstanding 2023 Notes with a coupon of 6.875%. On August 21, 2018, we issued $750.0 million of Original 2026 Notes with a coupon of 5.875% in a private placement. The Original 2026 Notes were issued at par value, and we received net proceeds of approximately $740.0 million, after deducting the initial purchasers’ discounts and estimated offering expenses. In conjunction with the 2026 Notes Offering, in August and September 2018, we completed the 2023 Notes Tender Offer and Redemption of all of our $575.0 million aggregate principal amount of 2023 Notes. We used a portion of the net proceeds from the 2026 Notes Offering to fund the 2023 Notes Tender Offer and Redemption.

On September 12, 2018, we announced the successful acquisition of 8,400 gross (8,400 net) leasehold acres in Lea and Eddy Counties, New Mexico for approximately $387 million, or a weighted average cost of approximately $46,000 per net acre, in the Bureau of Land Management New Mexico Oil and Gas Lease Sale on September 5 and 6, 2018 (the “BLM Acquisition”). We completed the BLM Acquisition on September 20, 2018, and we expect the leases will be issued to us in the fourth quarter of 2018. We financed the BLM Acquisition using cash on hand and borrowings under the Credit Agreement.

At September 30, 2018, we had $750.0 million of outstanding Original 2026 Notes, $325.0 million in borrowings outstanding under the Credit Agreement and approximately $3.0 million in outstanding letters of credit issued pursuant to the Credit Agreement. At September 30, 2018, we also had cash totaling approximately $45.9 million and restricted cash totaling approximately $7.1 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 our other cash and is to be used only to fund the capital expenditures and operations of these less-than-wholly-owned subsidiaries.

On October 4, 2018, we issued $300.0 million of Additional 2026 Notes. The Additional 2026 Notes were issued pursuant to, and are governed by, the same Indenture governing the Original 2026 Notes. The Additional 2026 Notes were issued at 100.5% of par, plus accrued interest from August 21, 2018. We received net proceeds from this offering of approximately $297.6 million, after deducting the initial purchasers’ discounts and estimated offering expenses but excluding accrued interest from August 21, 2018 paid by the initial purchasers of the Additional 2026 Notes. The proceeds from this offering were used to repay a portion of the $325.0 million in outstanding borrowings under the Credit Agreement, which were incurred in connection with the BLM Acquisition. The Notes will mature September 15, 2026, and interest is payable on the Notes semi-annually in arrears on each March 15 and September 15.

At October 31, 2018, we had $1.05 billion of outstanding Notes, $25.0 million in borrowings outstanding under the Credit Agreement and approximately $3.0 million in outstanding letters of credit issued pursuant to the Credit Agreement.

In October 2018, the lenders under our Credit Agreement completed their review of our proved oil and natural gas reserves at June 30, 2018. In connection with such review, we amended the Credit Agreement to, among other items, increase the maximum facility amount to $1.5 billion, increase the borrowing base to $850.0 million, increase the elected borrowing commitment to $500.0 million, extend the maturity to October 31, 2023 and reduce borrowing rates by 0.25% per annum. This October 2018 redetermination constituted the regularly scheduled November 1 redetermination. Borrowings under the Credit Agreement are limited to the lowest of the borrowing base, the maximum facility amount and the elected borrowing commitment.

During the third 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 through September 30, 2018. We expect to operate those six rigs in the Delaware Basin through the remainder of 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. We have continued to build significant optionality into our drilling program. Three of our rigs operate on longer-term contracts with remaining average terms between 12 and 15 months. The other three rigs are on short-term contracts with remaining obligations of six months or less. This affords us the ability to modify our drilling program as management may determine necessary based on changing commodity prices and other factors.

Effective October 1, 2018, we added a seventh operated drilling rig to our drilling program on a short-term contract. This seventh drilling rig was deployed initially in South Texas to drill up to ten wells, primarily in the Eagle Ford shale. This rig is expected to operate in South Texas throughout the fourth quarter of 2018 and into early 2019. At that time, subject to commodity prices and other economic circumstances, we anticipate moving this rig to the Delaware Basin, most likely to either the Arrowhead or Antelope Ridge asset area. We then expect to operate this seventh rig in the Delaware Basin throughout the remainder of 2019.

On August 1, 2018, we adjusted our anticipated 2018 capital expenditures for drilling and completions (including equipping wells for production) from $530 to $570 million to $620 to $650 million and our anticipated midstream capital expenditures remained $70 to $90 million, which primarily represents our 51% share of San Mateo's 2018 estimated capital expenditures. With the addition of the seventh drilling rig deployed to South Texas on October 1, 2018, we increased our anticipated 2018 capital expenditures for drilling and completions (including equipping wells for production) by approximately 4%, or $25 to $30 million, to $645 to $680 million. We have allocated substantially all of our estimated 2018 capital expenditures to the further delineation and development of our growing leasehold position and midstream assets in the Delaware Basin, with the exception of the South Texas drilling program beginning in the fourth quarter of 2018 and amounts allocated to limited non-operated activities in the Eagle Ford and Haynesville shales. For the remainder of 2018, our Delaware Basin drilling program will continue to focus on the development of the Wolf and Rustler Breaks asset areas and the further delineation and development of the Jackson Trust, Ranger/Arrowhead, Antelope Ridge and Twin Lakes asset areas, although we may also continue to delineate previously untested zones in the Wolf and Rustler Breaks asset areas.

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 realized oil, natural gas and NGL 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 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 September 30, 2018.

Our unaudited cash flows for the nine months ended September 30, 2018 and 2017 are presented below:

	Nine Months Ended September 30,	
(In thousands)	**2018**	**2017**
Net cash provided by operating activities	$ 419,318	$ 222,516
Net cash used in investing activities	(1,220,528)	(596,853)
Net cash provided by financing activities	751,736	191,117
Net change in cash and restricted cash	$ (49,474)	$ (183,220)
Adjusted EBITDA attributable to Matador Resources Company shareholders[1]	$ 409,984	$ 227,444

(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 $196.8 million to $419.3 million for the nine months ended September 30, 2018 from $222.5 million for the nine months ended September 30, 2017. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased to $405.0 million for the nine months ended September 30, 2018 from $210.7 million for the nine months ended September 30, 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 $2.5 million in net cash provided by operating activities for the nine months ended September 30, 2018, as compared to the nine months ended September 30, 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 increased by $623.7 million to $1.221 billion for the nine months ended September 30, 2018 from $596.9 million for the nine months ended September 30, 2017. This increase in net cash used in investing activities is primarily due to an increase of $589.3 million in oil and natural gas properties capital expenditures for the nine months ended September 30, 2018, as compared to the nine months ended September 30, 2017. Cash used for oil and natural gas properties capital expenditures for the nine months ended September 30, 2018 was attributable to the acquisition of additional leasehold and mineral interests including, primarily, the BLM Acquisition, and to our operated and non-operated drilling and completion activities in the Delaware Basin. The remaining increase was attributable to an increase in cash used for midstream and other property and equipment of $41.7 million primarily related to capital expenditures for San Mateo, which was partially offset by a net increase of $7.3 million in proceeds from the sale of acreage.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities increased by $560.6 million to $751.7 million for the nine months ended September 30, 2018 from $191.1 million for the nine months ended September 30, 2017. During the nine months ended September 30, 2018, we received net proceeds of $226.5 million from our May 2018 public equity offering, had borrowings under our credit agreement of $370.0 million, received net proceeds from the 2026 Notes Offering of $740.5 million and had an increase of $44.1 million in contributions from non-controlling interest owners in less-than-wholly-owned subsidiaries. These increases were offset by the repayment of the $45.0 million in borrowings under our Credit Agreement, the purchase of our 2023 Notes for $605.8 million, a decrease of $156.8 million in contributions related to the formation of San Mateo and an increase of $11.8 million in distributions to non-controlling interest owners in less-than-wholly-owned subsidiaries.

Non-GAAP Financial Measures

We define Adjusted EBITDA as earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, certain other non-cash items and non-cash stock-based compensation expense, and net gain or loss on asset sales and inventory impairment. Adjusted EBITDA is not a measure of net income (loss) or cash flows as determined by GAAP. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies.

Management believes Adjusted EBITDA is necessary because it allows us to evaluate our operating performance and compare the results of operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in calculating Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which certain assets were acquired.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income (loss) 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 September 30,		Nine Months Ended September 30,	
(In thousands)	**2018**	**2017**	**2018**	**2017**
Unaudited Adjusted EBITDA Reconciliation to Net Income:				
Net income attributable to Matador Resources Company shareholders	$ 17,794	$ 15,039	$ 137,494	$ 87,532
Net income attributable to non-controlling interest in subsidiaries	7,321	2,940	18,182	8,034
Net income	25,115	17,979	155,676	95,566
Interest expense	10,340	8,550	26,835	26,229
Depletion, depreciation and amortization	70,457	47,800	192,664	123,066
Accretion of asset retirement obligations	387	323	1,126	937
Unrealized loss (gain) on derivatives	21,337	12,372	9,492	(21,449)
Stock-based compensation expense	4,842	1,296	13,787	12,488
Net loss (gain) on asset sales and inventory impairment	196	(16)	196	(23)
Prepayment premium on extinguishment of debt	31,226	—	31,226	—
Consolidated Adjusted EBITDA	163,900	88,304	431,002	236,814
Adjusted EBITDA attributable to non-controlling interest in subsidiaries	(8,508)	(3,471)	(21,018)	(9,370)
Adjusted EBITDA attributable to Matador Resources Company shareholders	$ 155,392	$ 84,833	$ 409,984	$ 227,444

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In thousands)	**2018**	**2017**	**2018**	**2017**
Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities:				
Net cash provided by operating activities	$ 165,111	$ 101,274	$ 419,318	$ 222,516
Net change in operating assets and liabilities	(11,111)	(21,481)	(14,300)	(11,828)
Interest expense, net of non-cash portion	9,900	8,511	25,984	26,126
Adjusted EBITDA attributable to non-controlling interest in subsidiaries	(8,508)	(3,471)	(21,018)	(9,370)
Adjusted EBITDA attributable to Matador Resources Company shareholders	$ 155,392	$ 84,833	$ 409,984	$ 227,444

Net income attributable to Matador Resources Company shareholders increased by $2.8 million to $17.8 million for the three months ended September 30, 2018, as compared to $15.0 million for the three months ended September 30, 2017. This increase in net income attributable to Matador Resources Company shareholders for the three months ended September 30, 2018 as compared to the three months ended September 30, 2017 is primarily attributable to the increase in oil and natural gas revenues of $81.3 million, which was offset by a $9.0 million increase in unrealized loss on derivatives, a $39.6 million increase in total expenses and the $31.2 million in prepayment premium on extinguishment of debt.

Net income attributable to Matador Resources Company shareholders increased by $50.0 million to $137.5 million for the nine months ended September 30, 2018, as compared to $87.5 million for the nine months ended September 30, 2017. This increase in net income attributable to Matador Resources Company shareholders for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017 is primarily attributable to the increase in oil and natural gas revenues of $243.7 million, which was offset by a $30.9 million decrease in unrealized gain on derivatives, a $123.6 million increase in total expenses and the $31.2 million in prepayment premium on extinguishment of debt.

Adjusted EBITDA, a non-GAAP financial measure, increased by $70.6 million to $155.4 million for the three months ended September 30, 2018, as compared to $84.8 million for the three months ended September 30, 2017. This increase in our Adjusted EBITDA is primarily attributable to higher oil and natural gas production and higher oil and natural gas prices for the three months ended September 30, 2018, as compared to the three months ended September 30, 2017.

Adjusted EBITDA, a non-GAAP financial measure, increased by $182.5 million to $410.0 million for the nine months ended September 30, 2018, as compared to $227.4 million for the nine months ended September 30, 2017. This increase in our

Adjusted EBITDA is primarily attributable to higher oil and natural gas production and higher oil prices for the nine months ended September 30, 2018, as compared to the nine months ended September 30, 2017.

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 September 30, 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 September 30, 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)	$ 327,991	$ —	$ —	$ —	$ 327,991
Senior unsecured notes(2)	750,000	—	—	—	750,000
Office leases	21,035	2,647	5,388	5,604	7,396
Non-operated drilling commitments(3)	44,234	44,234	—		—
Drilling rig contracts(4)	32,790	30,771	2,019	—	—
Asset retirement obligations	29,634	928	1,106	2,229	25,371
Natural gas transportation, gathering and processing agreements with non-affiliates(5)	451,092	18,957	87,651	90,815	253,669
Gathering, processing and disposal agreements with San Mateo(6)	222,028	1,727	69,994	75,102	75,205
Natural gas construction contracts(7)	11,955	11,955	—	—	—
Total contractual cash obligations	$ 1,890,759	$ 111,219	$ 166,158	$ 173,750	$ 1,439,632

(1) The amounts included in the table above represent principal maturities only. At September 30, 2018, we had $325.0 million in borrowings outstanding under our Credit Agreement and approximately $3.0 million in outstanding letters of credit issued pursuant to the Credit Agreement. The Credit Agreement matures in October 2023.

(2) The amounts included in the table above represent principal maturities only. Interest expense on the Original 2026 Notes that were outstanding as of September 30, 2018 is expected to be approximately $44.1 million each year until maturity.

(3) At September 30, 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 September 30, 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 $44.2 million at September 30, 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. In the second quarter of 2018, we entered into a 16-year, fixed fee natural gas transportation agreement that begins on October 1, 2019, whereby 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. Additionally, in the second quarter of 2018, we entered into a short-term natural gas transportation agreement whereby 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. Lastly, in the second quarter of 2018, we entered into a 10-year, fixed-fee natural gas sales agreement whereby we committed to deliver residue natural gas through the counterparty’s pipeline to the Texas Gulf Coast beginning on the in-service date for such pipeline, which is expected to be operational 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.

(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 September 30, 2018, oil prices averaged $69.51 per Bbl, ranging from a high of $74.14 per Bbl in early July to a low of $65.01 per Bbl in mid-August, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. We realized a weighted average oil price of $57.15 per Bbl ($58.97 per Bbl including realized gains from oil derivatives) for our oil production for the three months ended September 30, 2018, as compared to $46.25 per Bbl ($46.47 per Bbl including realized gains from oil derivatives) for our production for the three months ended September 30, 2017. At October 31, 2018, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date had declined from the average price for the third quarter of 2018, settling at $65.31 per Bbl, which was a significant increase as compared to $54.38 per Bbl at October 31, 2017.

For the three months ended September 30, 2018, natural gas prices averaged $2.87 per MMBtu, ranging from a high of approximately $3.08 per MMBtu in late September to a low of approximately $2.72 per MMBtu in mid-July, 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 $3.77 per Mcf (with no realized gains or losses from natural gas derivatives) for our natural gas production (including revenues attributable to NGLs) for the three months ended September 30, 2018, as compared to $3.42 per Mcf (with no realized gains or losses from natural gas derivatives) for our natural gas production (including revenues attributable to NGLs) for the three months ended September 30, 2017. Our weighted average natural gas price was positively impacted by increasing NGL revenues during the third quarter of 2018 as compared to the third quarter of 2017. At October 31, 2018, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date had increased from the average price for the third quarter of 2018, settling at $3.26 per MMBtu, which was also an increase as compared to $2.90 per MMBtu at October 31, 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 and basis differentials. 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 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 the benchmark price and the price we receive is called a differential. At September 30, 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, and these differentials widened further in the second and third quarters. These widening differentials negatively impacted our oil and natural gas revenues throughout the third quarter of 2018, with oil price differentials reaching higher than ($16.00) per Bbl and natural gas price differentials reaching higher than ($1.25) per MMBtu in the latter part of the quarter. The oil price differentials have begun to narrow somewhat since September 30, 2018, but the natural gas price differentials have widened further. These oil and natural gas price differentials are expected to negatively impact our oil and natural gas revenues in the fourth quarter of 2018.

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 these price differentials could widen further in future periods. At September 30, 2018, we had approximately 45% to 50% of our anticipated Delaware Basin oil production for the fourth quarter 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 price 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 September 30, 2018, we had no hedges in place to mitigate our exposure to basis differentials for our natural gas production in 2018 and no basis hedges in place for either oil or natural gas production in 2019 or beyond.

These widening basis differentials are largely attributable to industry concerns regarding the near-term sufficiency of pipeline takeaway capacity for oil, natural gas and NGL production in the Delaware Basin. At October 31, 2018, we had not experienced material pipeline-related interruptions to our oil, natural gas or NGL production during 2018. During the third quarter of 2018, shortages of NGL fractionation capacity were experienced by certain operators in the Delaware Basin and elsewhere. We did not experience such problems in the third quarter of 2018, and although we do not expect to encounter fractionation capacity problems going forward, we can provide no assurances that such problems will not arise. If we do experience any interruptions with takeaway capacity or NGL fractionation, our oil and natural gas revenues, business, financial condition, results of operations and cash flows could be adversely affected.

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 magnitude of these increases.

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 September 30, 2018, Royal Bank of Canada, 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 September 30, 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 September 30, 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.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls during the three months ended September 30, 2018 that have materially affected or are reasonably likely to have a material effect on our internal control over financial reporting.

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 on 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 September 30, 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
July 1, 2018 to July 31, 2018	4,713	$ 31.63	—	—
August 1, 2018 to August 31, 2018	37,828	32.05	—	—
September 1, 2018 to September 30, 2018	2,827	32.81	—	—
Total	45,368	$ 32.05	—	—

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

Item 6. Exhibits

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).
4.1	Indenture, dated August 21, 2018, by and among the Company, the Guarantors and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on August 21, 2018).
4.2	Registration Rights Agreement, dated August 21, 2018, by and among the Company, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several initial purchasers named therein (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed on August 21, 2018).
4.3	Registration Rights Agreement, dated October 4, 2018, by and among the Company, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several initial purchasers named therein (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed on October 4, 2018).
10.1	First Amendment to the Employment Agreement between Matador Resources Company and Billy E. Goodwin (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the period ended June 30, 2018).
10.2	Amended and Restated Employment Agreement between Matador Resources Company and Bradley M. Robinson (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the period ended June 30, 2018).
10.3	Purchase Agreement, dated as of August 7, 2018, by and among the Company, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several initial purchasers named therein (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on August 9, 2018).
10.4	Purchase Agreement, dated as of October 1, 2018, by and among the Company, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several initial purchasers named therein (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on October 4, 2018).
10.5	Eleventh Amendment to Third Amended and Restated Credit Agreement, dated as of August 7, 2018, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on August 9, 2018).
10.6	Twelfth Amendment to Third Amended and Restated Credit Agreement, dated as of October 1, 2018, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on October 4, 2018).
10.7	Thirteenth Amendment to Third Amended and Restated Credit Agreement, dated as of October 31, 2018, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on November 1, 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 September 30, 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).

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: November 1, 2018	By:	/s/ Joseph Wm. Foran
		Joseph Wm. Foran
		Chairman and Chief Executive Officer
Date: November 1, 2018	By:	/s/ David E. Lancaster
		David E. Lancaster
		Executive Vice President and Chief Financial Officer

Exhibit 31.1

CERTIFICATION

I, Joseph Wm. Foran, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Matador Resources Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

November 1, 2018

/s/ Joseph Wm. Foran

Joseph Wm. Foran
Chairman and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, David E. Lancaster, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Matador Resources Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

November 1, 2018

/s/ David E. Lancaster

David E. Lancaster
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the quarterly report of Matador Resources Company (the “Company”) on Form 10-Q for the period ended September 30, 2018 as filed with the Securities and Exchange Commission on the date hereof (the “Form 10-Q”), I, Joseph Wm. Foran, hereby certify in my capacity as Chairman and Chief Executive Officer of the Company, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Form 10-Q fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company.

November 1, 2018	/s/ Joseph Wm. Foran
	Joseph Wm. Foran
	Chairman and Chief Executive Officer (Principal Executive Officer)

Exhibit 32.2

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the quarterly report of Matador Resources Company (the “Company”) on Form 10-Q for the period ended September 30, 2018 as filed with the Securities and Exchange Commission on the date hereof (the “Form 10-Q”), I, David E. Lancaster, hereby certify in my capacity as Executive Vice President and Chief Financial Officer of the Company, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Form 10-Q fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company.

November 1, 2018	/s/ David E. Lancaster
	David E. Lancaster
	Executive Vice President and Chief Financial Officer (Principal Financial Officer)