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

FORM 10-Q

(Mark One)

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

For the Quarterly Period Ended September 30, 2017

OR

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

For the transition period _______________ to _______________

Commission File Number: 001-37362

Black Stone Minerals, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**47-1846692**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
1001 Fannin Street, Suite 2020 Houston, Texas	**77002**
(Address of principal executive offices)	**(Zip code)**

(713) 445-3200
(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. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	☒		Accelerated filer	☐
Non-accelerated filer	☐	(Do not check if a smaller reporting company)	Smaller reporting company	☐
			Emerging growth company	☐

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

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

As of November 1, 2017, there were 103,417,081 common limited partner units, 95,388,424 subordinated limited partner units, and 26,426 preferred units of the registrant outstanding.

TABLE OF CONTENTS

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In thousands)	September 30, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 8,911	$ 9,772
Accounts receivable	68,895	68,181
Commodity derivative assets	4,724	—
Prepaid expenses and other current assets	1,269	1,036
TOTAL CURRENT ASSETS	83,799	78,989
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, at cost, using the successful efforts method of accounting, includes unproved properties of $731,978 and $605,736 at September 30, 2017 and December 31, 2016, respectively	2,892,447	2,697,073
Accumulated depreciation, depletion, amortization, and impairment	(1,736,695)	(1,652,930)
Oil and natural gas properties, net	1,155,752	1,044,143
Other property and equipment, net of accumulated depreciation of $14,384 and $14,327 at September 30, 2017 and December 31, 2016, respectively	519	528
NET PROPERTY AND EQUIPMENT	1,156,271	1,044,671
DEFERRED CHARGES AND OTHER LONG-TERM ASSETS	6,000	5,167
TOTAL ASSETS	$ 1,246,070	$ 1,128,827
LIABILITIES, MEZZANINE EQUITY AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 3,659	$ 4,142
Accrued liabilities	38,336	50,952
Commodity derivative liabilities	—	16,237
Other current liabilities	302	—
TOTAL CURRENT LIABILITIES	42,297	71,331
LONG-TERM LIABILITIES		
Credit facility	362,000	316,000
Accrued incentive compensation	2,883	1,485
Commodity derivative liabilities	—	482
Deferred revenue	—	518
Asset retirement obligations	13,909	13,350
Other long-term liability	6,592	—
TOTAL LIABILITIES	427,681	403,166
COMMITMENTS AND CONTINGENCIES (Note 8)		
MEZZANINE EQUITY		
Partners' equity - convertible redeemable preferred units, 26 and 53 units outstanding at September 30, 2017 and December 31, 2016, respectively	27,092	54,015
EQUITY		
Partners' equity - general partner interest	—	—
Partners' equity - common units, 103,324 and 95,721 units outstanding at September 30, 2017 and December 31, 2016, respectively	608,998	489,023
Partners' equity - subordinated units, 95,388 and 95,164 units outstanding at September 30, 2017 and December 31, 2016, respectively	181,395	181,602
Noncontrolling interests	904	1,021
TOTAL EQUITY	791,297	671,646
TOTAL LIABILITIES, MEZZANINE EQUITY AND EQUITY	$ 1,246,070	$ 1,128,827

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

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)
(In thousands, except per unit amounts)

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
REVENUE				
Oil and condensate sales	$ 41,361	$ 42,780	$ 119,097	$ 104,581
Natural gas and natural gas liquids sales	45,047	38,986	142,651	85,706
Gain (loss) on commodity derivative instruments	(9,341)	7,813	35,387	(12,295)
Lease bonus and other income	12,044	9,592	37,082	26,129
TOTAL REVENUE	89,111	99,171	334,217	204,121
OPERATING (INCOME) EXPENSE				
Lease operating expense	4,569	5,007	12,906	14,179
Production costs and ad valorem taxes	11,549	9,228	35,314	23,301
Exploration expense	8	6	616	643
Depreciation, depletion, and amortization	29,204	28,731	84,483	79,654
Impairment of oil and natural gas properties	—	—	—	6,775
General and administrative	17,305	16,677	51,998	52,213
Accretion of asset retirement obligations	260	206	760	680
(Gain) loss on sale of assets, net	—	—	(931)	(4,772)
TOTAL OPERATING EXPENSE	62,895	59,855	185,146	172,673
INCOME (LOSS) FROM OPERATIONS	26,216	39,316	149,071	31,448
OTHER INCOME (EXPENSE)				
Interest and investment income	(9)	460	30	651
Interest expense	(4,172)	(2,282)	(11,660)	(4,773)
Other income (expense)	(1)	41	352	148
TOTAL OTHER EXPENSE	(4,182)	(1,781)	(11,278)	(3,974)
NET INCOME (LOSS)	22,034	37,535	137,793	27,474
NET (INCOME) LOSS ATTRIBUTABLE TO NONCONTROLLING INTERESTS	20	8	27	15
DISTRIBUTIONS ON REDEEMABLE PREFERRED UNITS	(666)	(1,324)	(2,452)	(4,439)
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON AND SUBORDINATED UNITS	$ 21,388	$ 36,219	$ 135,368	$ 23,050
ALLOCATION OF NET INCOME (LOSS):				
General partner interest	$ —	$ —	$ —	$ —
Common units	16,371	23,114	83,989	24,343
Subordinated units	5,017	13,105	51,379	(1,293)
	$ 21,388	$ 36,219	$ 135,368	$ 23,050
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON AND SUBORDINATED UNIT:				
Per common unit (basic)	$ 0.16	$ 0.24	$ 0.86	$ 0.26
Weighted average common units outstanding (basic)	101,623	95,740	97,777	95,086
Per subordinated unit (basic)	$ 0.05	$ 0.14	$ 0.54	$ (0.01)
Weighted average subordinated units outstanding (basic)	95,388	95,189	95,269	95,125
Per common unit (diluted)	$ 0.16	$ 0.24	$ 0.86	$ 0.26
Weighted average common units outstanding (diluted)	101,623	96,011	97,777	95,619
Per subordinated unit (diluted)	$ 0.05	$ 0.14	$ 0.54	$ (0.01)
Weighted average subordinated units outstanding (diluted)	95,388	95,189	95,269	95,467
DISTRIBUTIONS DECLARED AND PAID:				
Per common unit	$ 0.3125	$ 0.2875	$ 0.8875	$ 0.8125
Per subordinated unit	$ 0.2088	$ 0.1838	$ 0.5763	$ 0.5513

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

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF EQUITY
(Unaudited)
(In thousands)

	Common units	Subordinated units	Partners' equity—common units	Partners' equity—subordinated units	Noncontrolling interests	Total equity
BALANCE AT DECEMBER 31, 2016	95,721	95,164	$ 489,023	$ 181,602	$ 1,021	$ 671,646
Restricted units granted, net of forfeitures	1,576	—	—	—	—	—
Equity-based compensation	—	—	26,430	(114)	—	26,316
Conversion of redeemable preferred units	201	263	2,868	3,756	—	6,624
Repurchases of common and subordinated units	(427)	(39)	(7,553)	(292)	—	(7,845)
Issuance of units for property acquisitions	4,341	—	71,592	—	—	71,592
Distributions	—	—	(87,651)	(54,924)	(90)	(142,665)
Charges to partners' equity for accrued distribution equivalent rights	—	—	(979)	—	—	(979)
Net income (loss)	—	—	85,243	52,577	(27)	137,793
Issuance of common units, net of offering costs	1,912	—	31,267	—	—	31,267
Distributions on redeemable preferred units	—	—	(1,242)	(1,210)	—	(2,452)
BALANCE AT SEPTEMBER 30, 2017	103,324	95,388	$ 608,998	$ 181,395	$ 904	$ 791,297

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

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(In thousands)

	Nine Months Ended September 30, 2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income (loss)	$ 137,793	$ 27,474
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, and amortization	84,483	79,654
Impairment of oil and natural gas properties	—	6,775
Accretion of asset retirement obligations	760	680
Amortization of deferred charges	661	594
(Gain) loss on commodity derivative instruments	(35,387)	12,295
Net cash received on settlement of commodity derivative instruments	12,339	39,220
Equity-based compensation	18,614	33,120
(Gain) loss on sale of assets, net	(931)	(4,772)
Changes in operating assets and liabilities:		
Accounts receivable	(709)	(23,144)
Prepaid expenses and other current assets	(234)	(862)
Accounts payable and accrued liabilities	(3,940)	(29,063)
Deferred revenue	(1,670)	(175)
Settlement of asset retirement obligations	(113)	(237)
NET CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES	211,666	141,559
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisitions of oil and natural gas properties	(89,030)	(140,893)
Additions to oil and natural gas properties	(40,680)	(63,039)
Purchases of other property and equipment	(118)	(5)
Proceeds from farmout of oil and gas properties	6,592	—
Proceeds from the sale of oil and natural gas properties	6,754	177
NET CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES	(116,482)	(203,760)
CASH FLOWS FROM FINANCING ACTIVITIES		
Borrowings under senior line of credit	208,500	304,500
Repayments of borrowings under senior line of credit	(162,500)	(71,500)
Distributions to Black Stone Minerals, L.P. common and subordinated unitholders	(142,575)	(130,883)
Distributions to redeemable preferred unitholders	(3,111)	(5,061)
Distributions to non-controlling interests	(90)	(83)
Proceeds from issuance of common units	31,267	—
Redemptions of redeemable preferred units	(19,641)	(18,461)
Loan origination fees	(50)	—
Repurchases of common and subordinated units	(7,845)	(24,696)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(96,045)	53,816
NET CHANGE IN CASH AND CASH EQUIVALENTS	(861)	(8,385)
CASH AND CASH EQUIVALENTS - beginning of the period	9,772	13,233
CASH AND CASH EQUIVALENTS - end of the period	$ 8,911	$ 4,848
SUPPLEMENTAL DISCLOSURE		
Interest paid	$ 11,041	$ 4,060

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

NOTE 1—BUSINESS AND BASIS OF PRESENTATION

Description of the Business

Black Stone Minerals, L.P. (“BSM” or the “Partnership”) is a publicly traded Delaware limited partnership formed on September 16, 2014. On May 6, 2015, BSM completed its initial public offering (the “IPO”) of 22,500,000 common units representing limited partner interests at a price to the public of $19.00 per common unit. BSM received proceeds of $391.5 million from the sale of its common units, net of underwriting discount, structuring fee, and offering expenses (including costs previously incurred and capitalized). BSM used the net proceeds from the IPO to repay substantially all indebtedness outstanding under its credit facility. On May 1, 2015, BSM’s common units began trading on the New York Stock Exchange under the symbol “BSM.”

Black Stone Minerals Company, L.P., a Delaware limited partnership, and its subsidiaries (collectively referred to as “BSMC” or the “Predecessor”) own oil and natural gas mineral interests in the United States. In connection with the IPO, BSMC was merged into a wholly owned subsidiary of BSM, with BSMC as the surviving entity. Pursuant to the merger, the Class A and Class B common units representing limited partner interests of the Predecessor were converted into an aggregate of 72,574,715 common units and 95,057,312 subordinated units of BSM at a conversion ratio of 12.9465:1 for 0.4329 common units and 0.5671 subordinated units, and the preferred units of BSMC were converted into an aggregate of 117,963 preferred units of BSM at a conversion ratio of one to one. The merger was accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests. Unless otherwise stated or the context otherwise indicates, all references to the “Partnership” or similar expressions for time periods prior to the IPO refer to Black Stone Minerals Company, L.P. and its subsidiaries, the Predecessor, for accounting purposes. For time periods subsequent to the IPO, these terms refer to Black Stone Minerals, L.P. and its subsidiaries.

In addition to mineral interests, which make up the vast majority of the asset base, the Partnership’s assets also include nonparticipating and overriding royalty interests. These interests, which are non-cost-bearing, are collectively referred to as “mineral and royalty interests.” As of September 30, 2017, the Partnership’s mineral and royalty interests were located in 41 states and 64 onshore oil and natural gas producing basins of the continental United States, including all of the major onshore producing basins. The Partnership also owns non-operated working interests in certain oil and natural gas properties.

Basis of Presentation

The accompanying unaudited interim consolidated financial statements of the Partnership have been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP") and pursuant to the rules and regulations of the U.S. Securities and Exchange Commission (“SEC”). These unaudited interim consolidated financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with U.S. GAAP. Accordingly, the accompanying unaudited interim consolidated financial statements and related notes should be read in conjunction with the Partnership’s consolidated financial statements included in the Partnership’s 2016 Annual Report on Form 10-K. The financial statements include the consolidated results of the Partnership. All intercompany balances and transactions have been eliminated.

Certain reclassifications have been made to the prior periods presented to conform to the current period financial statement presentation. The reclassifications have no effect on the consolidated financial position, results of operations, or cash flows of the Partnership.

In the opinion of management, all material adjustments, which are of a normal and recurring nature, necessary for the fair presentation of the financial results for all periods presented have been reflected. The results of operations for the nine months ended September 30, 2017 are not necessarily indicative of the results to be expected for the full year.

The Partnership evaluates the significant terms of its investments to determine the method of accounting to be applied to each respective investment. Investments in which the Partnership has less than a 20% ownership interest and does not have control or exercise significant influence are accounted for under the cost method. The Partnership’s cost method investment is included in deferred charges and other long-term assets in the consolidated balance sheets. Investments in which the Partnership exercises control are consolidated, and the noncontrolling interests of such investments, which are not attributable directly or indirectly to the Partnership, are presented as a separate component of net income and equity in the accompanying consolidated financial statements.

The consolidated financial statements include undivided interests in oil and natural gas property rights. The Partnership accounts for its share of oil and natural gas property rights by reporting its proportionate share of assets, liabilities, revenues, costs, and cash flows within the relevant lines on the accompanying consolidated balance sheets, statements of operations, and statements of cash flows.

Segment Reporting

The Partnership operates in a single operating and reportable segment. Operating segments are defined as components of an enterprise for which separate financial information is evaluated regularly by the chief operating decision maker in deciding how to allocate resources and assess performance. The Partnership's chief executive officer has been determined to be the chief operating decision maker and allocates resources and assesses performance based upon financial information at the consolidated level.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Significant Accounting Policies

Significant accounting policies are disclosed in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2016. There have been no changes in such policies or the application of such policies during the nine months ended September 30, 2017.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, *Revenue from Contracts with Customers* (Topic 606) that will supersede Accounting Standards Codification ("ASC") 605, *Revenue Recognition*. Under the new standard, entities will be required to use judgment and make estimates, including identifying performance obligations in a contract, estimating the amount of variable consideration to include in the transaction price, allocating the transaction price to each separate performance obligation, and determining when an entity satisfies its performance obligations. The new standard also requires more detailed disclosures related to the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The new guidance is effective for fiscal years and interim periods beginning after December 15, 2017, with early adoption permitted. The standard allows for either "full retrospective" adoption, meaning that the standard is applied to all of the periods presented with a cumulative catch-up adjustment as of the earliest period presented, or "modified retrospective" adoption, meaning the standard is applied only to the most current period presented in the financial statements with a cumulative catch-up as of the current period.

The Partnership intends to use the modified retrospective adoption approach and does not plan to early adopt. The Partnership has completed its review of a representative sample of revenue contracts covering its material revenue streams that was designed to evaluate any potential changes in revenue recognition upon adoption of the new standard, and based on evaluations to-date, the implementation of the new standard is not anticipated to have a material impact on the consolidated financial statements. The Partnership is concurrently evaluating the information technology and internal control changes that will be required to implement the new standard based on the results of its contract review process. The Partnership continues to evaluate the disclosure requirements of this new guidance, and expects to fully complete its evaluation of the impacts of ASU 2014-09 to the consolidated financial statements and related disclosures by 2017 year end.

In February 2016, the FASB issued ASU 2016-02, *Leases* (Topic 842), which requires lessees to recognize the lease assets and lease liabilities classified as operating leases on the balance sheet. The new standard will be effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, and early adoption is permitted. The Partnership will use the modified retrospective adoption approach and does not plan to early adopt. Based on current evaluations to-date, the Partnership does not anticipate this new guidance will have a material impact on its consolidated financial statements and related disclosures as this guidance does not apply to leases to explore for or use minerals, oil, natural gas, and similar resources.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments* (Topic 230), to address diversity in practice of how certain cash receipts and cash payments are currently presented and classified in the statement of cash flows. The ASU addresses the topic of separately identifiable cash flows and application of the predominance principle. Classification of cash receipts and payments that have aspects of more than one class of cash flows should be determined first by applying specific guidance, and then by the nature of each separately identifiable cash flow. In situations where there is an absence of specific guidance and the cash flow has aspects of more than one type of classification, the predominance principle should be applied whereby the cash flow classification should depend on the activity that is likely to be the predominant source or use of cash flows. The new guidance is effective for public business entities for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, and early adoption is permitted. The Partnership intends to use the retrospective transition method, does not plan to early adopt, and is evaluating the impact that the new accounting guidance will have on its consolidated financial statements and related disclosures.

In January 2017, the FASB issued ASU 2017-01, *Business Combinations* (Topic 805), which clarifies the definition of a business in order to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The FASB issued this ASU in response to stakeholder feedback that the current definition of a business in ASC 805 is being applied too broadly and the application of the guidance was not resulting in consistent application in a cost-effective manner. This ASU provides a screen whereby a transaction will be accounted for as an asset purchase (or disposal) if substantially all of the fair value of the gross assets acquired (disposed) is concentrated in a single identifiable asset or a group of similar identifiable assets. If the screen is not met, the entity will evaluate whether it is a business acquisition under revised criteria. The ASU is effective for public business entities for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted under certain circumstances. The amendments in this ASU should be applied prospectively as of the beginning of the period of adoption. The Partnership does not plan to early adopt and is evaluating the impact that the new accounting guidance will have on its consolidated financial statements and related disclosures.

In May 2017, the FASB issued ASU 2017-09 *Compensation-Stock Compensation: Scope of Modification Accounting* (Topic 718). The update provides guidance about which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting under Topic 718. The amendments require an entity to account for the effects of a modification unless all of the following conditions are met:

- The fair value (or intrinsic or calculated value if elected) of the modified award is the same as the value of the original award immediately before the original award was modified.
- The vesting conditions of the modified award are the same as the vesting conditions of the original award immediately before the original award is modified.
- The classification of the modified award as an equity instrument or a liability instrument is the same as the classification of the original award immediately before the original award is modified.

This ASU is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted. The amendments in this ASU should be applied prospectively to an award modified on or after the adoption date. The Partnership does not plan to early adopt and is evaluating the impact that the new accounting guidance will have on its consolidated financial statements and related disclosures.

NOTE 3—ASSET RETIREMENT OBLIGATIONS

The asset retirement obligations ("ARO") liability reflects the present value of estimated costs of dismantlement, removal, site reclamation, and similar activities associated with the Partnership's working-interest oil and natural gas properties. The Partnership utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. The Partnership estimates the ultimate productive life of its properties, a credit-adjusted risk-free rate, and an inflation factor in order to determine the current present value of these obligations. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and natural gas property balance. The following table describes changes to the Partnership's ARO liability during the period:

	For the nine months ended September 30, 2017
	(In thousands)
Beginning asset retirement obligations	$ 13,350
Liabilities incurred	290
Liabilities settled	(113)
Accretion expense	760
Dispositions	(5)
Revisions	(71)
Ending asset retirement obligations	$ 14,211
Current asset retirement obligations	$ 302
Non-current asset retirement obligations	$ 13,909

NOTE 4—ACQUISITIONS AND DISPOSITIONS

Acquisitions of proved oil and natural gas properties and working interests are considered business combinations and are recorded at their estimated fair value as of the acquisition date. Acquisitions of unproved oil and natural gas properties are considered asset acquisitions and are recorded at cost.

2017 Acquisitions

During the nine months ended September 30, 2017, the Partnership closed on multiple acquisitions of mineral and royalty interests in the Delaware Basin and East Texas, which also included producing properties.

The following table summarizes the asset acquisitions which included producing properties:

	Proved	Unproved	Net Working Capital	Total Fair Value	Acquisition-Related Costs[1]	Cash	Fair Value of Common Units Issued
	(in thousands)						
January	$ 5,135	$ 34,008	$ 263	$ 39,406	$ 1,162	$ 27,380	$ 12,026
June	5,006	45,477	—	50,483	1,468	4,802	45,681
August	3,277	9,984	—	13,261	89	4,289	8,972
September	3,120	—	—	3,120	—	3,120	—
Total fair value	$ 16,538	$ 89,469	$ 263	$ 106,270	$ 2,719	$ 39,591	$ 66,679

[1] Acquisition-related costs were expensed and included in the general and administrative line item of the 2017 consolidated statement of operations.

In addition, the Partnership acquired mineral and royalty interests from various sellers in East Texas as follows:

	Unproved	Cash	Fair Value of Common Units Issued
	(in thousands)		
Q1 2017	$ 21,189	$ 21,017	$ 172
Q2 2017	13,329	13,329	—
Q3 2017	19,946	15,205	4,741
	$ 54,464	$ 49,551	$ 4,913

The cash portion of all acquisitions during the nine months ended September 30, 2017 was funded via borrowings under the Partnership's credit facility.

Canaan Farmout

On February 21, 2017, the Partnership announced that it had entered into a farmout agreement with Canaan Resource Partners ("Canaan") which covers certain Haynesville and Bossier shale acreage in San Augustine County, Texas operated by XTO Energy Inc. The Partnership has an approximate 50% working interest in the acreage and is the largest mineral owner. A total of 18 wells are anticipated to be drilled over an initial phase, beginning with wells spud after January 1, 2017. At its option, Canaan may participate in two additional phases with each phase continuing for the lesser of two years or until an additional 20 wells have been drilled. During the first three phases of the agreement, Canaan will commit on a phase-by-phase basis and fund 80% of the Partnership's drilling and completion costs and will be assigned 80% of the Partnership's working interests in such wells (40% working interest on an 8/8ths basis). After the third phase, Canaan can earn 40% of the Partnership’s working interest (20% working interest on an 8/8ths basis) in additional wells drilled in the area by continuing to fund 40% of the Partnership's costs for those wells on a well-by-well basis. The Partnership will receive an overriding royalty interest (“ORRI”) before payout and an increased ORRI after payout on all wells drilled under the agreement. The execution of this agreement is anticipated to offset the Partnership's future capital expenditures by approximately $30 to $35 million in 2017 and by an average of $40 to $50 million annually during the term of the agreement.

2016 Acquisitions

During the nine months ended September 30, 2016, the Partnership acquired producing oil and natural gas properties and unproved acreage across a diverse oil and natural gas mineral asset package, including an acquisition in June 2016 in the DJ Basin. The following table summarizes the fair values assigned to the properties acquired:

	Proved	Unproved	Net Working Capital	ARO	Total Fair Value	Cash
	(in thousands)					
June	$ 39,735	$ 79,827	$ 2,064	$ (50)	$ 121,576	$ 121,576

The Partnership also acquired unproved mineral and royalty interests in the Permian Basin and Midland Basin for $10 million and $8.3 million in cash, respectively. Additionally, throughout 2016, the Partnership funded certain other oil and natural gas asset acquisitions for an aggregate amount of $1.0 million in cash. All 2016 acquisition transactions were funded via borrowings under the Partnership's credit facility.

NOTE 5—DERIVATIVES AND FINANCIAL INSTRUMENTS

The Partnership’s ongoing operations expose it to changes in the market price for oil and natural gas. To mitigate the inherent commodity price risk associated with its operations, the Partnership uses oil and natural gas derivative instruments. From time to time, such instruments may include fixed-price-swap contracts, costless collars, and other contractual arrangements. The Partnership enters into oil and natural gas derivative contracts that contain netting arrangements with each counterparty. The Partnership does not enter into derivative instruments for speculative purposes.

As of September 30, 2017, the Partnership’s open derivative contracts consisted of only fixed-price-swap contracts. A fixed-price-swap contract between the Partnership and the counterparty specifies a fixed commodity price and a future settlement date. The Partnership has not designated any of its contracts as fair value or cash flow hedges. Accordingly, any changes in the fair value of the contracts are included in the consolidated statement of operations in the period of the change. All derivative gains and losses from the Partnership’s derivative contracts have been recognized in “Revenue” in the Partnership's accompanying consolidated statements of operations. Derivative instruments that have not yet been settled in cash are reflected as either derivative assets or liabilities in the Partnership’s accompanying consolidated balance sheets as of September 30, 2017 and December 31, 2016. See Note 6 – Fair Value Measurement for further discussion.

The Partnership's derivative contracts expose it to credit risk in the event of nonperformance by counterparties. While the Partnership does not require its derivative contract counterparties to post collateral, the Partnership does evaluate the credit standing of such counterparties as deemed appropriate. This evaluation includes reviewing a counterparty’s credit rating and latest financial information. As of September 30, 2017, the Partnership had nine counterparties, all of which are rated Baa1 or better by Moody’s. Seven of the Partnership's counterparties are lenders under the Partnership's credit facility. The Partnership would have been at risk of losing a fair value amount of $7.2 million had the Partnership's counterparties as a group been unable to fulfill their obligations as of September 30, 2017.

The table below summarizes the fair value and classification of the Partnership's derivative instruments:

As of September 30, 2017

Classification	Balance Sheet Location	Gross Fair Value	Effect of Counterparty Netting	Net Carrying Value on Balance Sheet
			(In thousands)	
Assets:				
Current asset	Commodity derivative assets	$ 5,338	$ (614)	$ 4,724
Long-term asset	Deferred charges and other long-term assets	1,822	(217)	1,605
Total assets		$ 7,160	$ (831)	$ 6,329
Liabilities:				
Current liability	Commodity derivative liabilities	$ 614	$ (614)	$ —
Long-term liability	Commodity derivative liabilities	217	(217)	—
Total liabilities		$ 831	$ (831)	$ —

As of December 31, 2016

Classification	Balance Sheet Location	Gross Fair Value	Effect of Counterparty Netting	Net Carrying Value on Balance Sheet
			(In thousands)	
Assets:				
Current asset	Commodity derivative assets	$ 3,879	$ (3,879)	$ —
Long-term asset	Deferred charges and other long-term assets	—	—	—
Total assets		$ 3,879	$ (3,879)	$ —
Liabilities:				
Current liability	Commodity derivative liabilities	$ 20,116	$ (3,879)	$ 16,237
Long-term liability	Commodity derivative liabilities	482	—	482
Total liabilities		$ 20,598	$ (3,879)	$ 16,719

Changes in the fair values of the Partnership's derivative instruments (both assets and liabilities) are presented on a net basis in the accompanying consolidated statements of operations. Changes in the fair value of the Partnership's commodity derivative instruments (both assets and liabilities) are as follows:

Derivatives not designated as hedging instruments	For the Nine Months Ended September 30, 2017	2016
	(In thousands)	
Beginning fair value of commodity derivative instruments	$ (16,719)	$ 64,534
Gain (loss) on oil derivative instruments	18,306	(8,906)
Gain (loss) on natural gas derivative instruments	17,081	(3,389)
Net cash received on settlements of oil derivative instruments	(10,682)	(23,034)
Net cash received on settlements of natural gas derivative instruments	(1,657)	(16,186)
Net change in fair value of commodity derivative instruments	23,048	(51,515)
Ending fair value of commodity derivative instruments	$ 6,329	$ 13,019

The Partnership had the following open derivative contracts for oil as of September 30, 2017:

Period and Type of Contract	Volume (Bbl)	Weighted Average Price (Per Bbl)	Range (Per Bbl) Low	Range (Per Bbl) High
Oil Swap Contracts:				
2017				
Third Quarter	172,000	$ 53.31	$ 52.40	$ 55.23
Fourth Quarter	687,000	53.21	52.02	55.23
2018				
First Quarter	611,000	$ 54.18	$ 52.09	$ 55.05
Second Quarter	573,000	54.16	52.09	54.90
Third Quarter	541,000	54.16	51.85	54.90
Fourth Quarter	502,000	54.22	51.85	54.90

The Partnership had the following open derivative contracts for natural gas as of September 30, 2017:

Period and Type of Contract	Volume (MMBtu)	Weighted Average Price (Per MMBtu)	Range (Per MMBtu) Low	Range (Per MMBtu) High
Natural Gas Swap Contracts:				
2017				
Fourth Quarter	13,130,000	$ 3.13	$ 2.92	$ 3.57
2018				
First Quarter	12,570,000	$ 3.06	$ 2.96	$ 3.45
Second Quarter	11,340,000	3.03	2.86	3.23
Third Quarter	9,630,000	3.02	2.90	3.23
Fourth Quarter	8,210,000	3.01	2.90	3.23

Subsequent to September 30, 2017, the Partnership entered into the following oil derivative contracts:

Period and Type of Contract	Volume (Bbl)	Weighted Average Price (Per Bbl)	Range (Per Bbl) Low	Range (Per Bbl) High
Oil Swap Contracts:				
2017				
Fourth Quarter	30,000	$ 56.51	$ 55.87	$ 57.15
2018				
First Quarter	130,000	$ 55.02	$ 53.99	$ 57.15
Second Quarter	175,000	54.73	53.99	56.75
Third Quarter	215,000	54.71	53.99	55.87
Fourth Quarter	255,000	54.22	52.82	55.87
2019				
First Quarter	165,000	$ 53.58	$ 52.82	$ 54.02
Second Quarter	165,000	53.58	52.82	54.02
Third Quarter	165,000	53.58	52.82	54.02
Fourth Quarter	165,000	53.58	52.82	54.02

Additionally, subsequent to September 30, 2017, the Partnership entered into the following natural gas derivative contracts:

Period and Type of Contract	Volume (MMBtu)	Weighted Average Price (per MMBtu)	Range (Per MMBtu) Low	Range (Per MMBtu) High
Natural Gas Swap Contracts:				
2018				
First Quarter	1,020,000	$ 3.11	$ 3.01	$ 3.21
Second Quarter	2,320,000	3.00	2.93	3.04
Third Quarter	3,970,000	3.00	2.93	3.04
Fourth Quarter	5,420,000	3.00	2.92	3.04
2019				
First Quarter	3,600,000	$ 2.91	$ 2.90	$ 2.93
Second Quarter	3,600,000	2.91	2.90	2.93
Third Quarter	3,600,000	2.91	2.90	2.93
Fourth Quarter	3,600,000	2.91	2.90	2.93

NOTE 6—FAIR VALUE MEASUREMENT

Fair value is defined as the amount at which an asset (or liability) could be bought (or incurred) or sold (or settled) in an orderly transaction between market participants at the measurement date. Further, ASC 820 establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value, and includes certain disclosure requirements. Fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability, including estimates of risk.

ASC 820 establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

Level 1—Unadjusted quoted prices for identical assets or liabilities in active markets.

Level 2—Quoted prices for similar assets or liabilities in non-active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

Level 3—Inputs that are unobservable and significant to the fair value measurement (including the Partnership’s own assumptions in determining fair value).

A financial instrument’s categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Partnership’s assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. There were no transfers into, or out of, the three levels of the fair value hierarchy for the nine months ended September 30, 2017 or the year ended December 31, 2016.

The carrying value of the Partnership's cash and cash equivalents, receivables, and payables approximate fair value due to the short-term nature of the instruments. The estimated carrying value of all debt as of September 30, 2017 and December 31, 2016 approximated the fair value due to variable market rates of interest. These debt fair values, which are Level 3 measurements, were estimated based on the Partnership’s incremental borrowing rates for similar types of borrowing arrangements, when quoted market prices were not available. The estimated fair values of the Partnership’s financial instruments are not necessarily indicative of the amounts that would be realized in a current market exchange.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The Partnership estimated the fair value of derivative instruments using the market approach via a model that uses inputs that are observable in the market or can be derived from, or corroborated by, observable data. See Note 5 – Derivatives and Financial Instruments for further discussion.

The following table presents information about the Partnership's assets and liabilities measured at fair value on a recurring basis:

	Fair Value Measurements Using			Effect of Counterparty Netting	Total
	Level 1	Level 2	Level 3		
			(In thousands)		
As of September 30, 2017					
Financial Assets					
Commodity derivative instruments	$ —	$ 7,160	$ —	$ (831)	$ 6,329
Financial Liabilities					
Commodity derivative instruments	$ —	$ 831	$ —	$ (831)	$ —
As of December 31, 2016					
Financial Assets					
Commodity derivative instruments	$ —	$ 3,879	$ —	$ (3,879)	$ —
Financial Liabilities					
Commodity derivative instruments	$ —	$ 20,598	$ —	$ (3,879)	$ 16,719

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Nonfinancial assets and liabilities measured at fair value on a nonrecurring basis include certain nonfinancial assets and liabilities, as may be acquired in a business combination, and measurements of oil and natural gas property values for assessment of impairment.

The determination of the fair values of proved and unproved properties acquired in business combinations are estimated by discounting projected future cash flows. The factors used to determine fair value include estimates of economic reserves, future operating and development costs, future commodity prices, and a risk-adjusted discount rate. The Partnership has designated these measurements as Level 3. The Partnership's fair value assessments for recent acquisitions are included in Note 4 – Acquisitions and Dispositions.

Oil and natural gas properties are measured at fair value on a nonrecurring basis using the income approach when assessing for impairment. Proved and unproved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of those properties. When assessing producing properties for impairment, the Partnership compares the expected undiscounted projected future cash flows of the producing properties to the carrying amount of the producing properties to determine recoverability. When the carrying amount exceeds its estimated undiscounted future cash flows, the carrying amount is written down to its fair value, which is measured as the present value of the projected future cash flows of such properties. The factors used to determine fair value include estimates of economic reserves, future operating and development costs, future commodity prices, and a risk-adjusted discount rate.

The Partnership's estimates of fair value have been determined at discrete points in time based on relevant market data. These estimates involve uncertainty and cannot be determined with precision. There were no significant changes in valuation techniques or related inputs as of September 30, 2017 or December 31, 2016.

The following table presents information about the Partnership's assets measured at fair value on a nonrecurring basis:

	Fair Value Measurements Using[1]			Net Book Value[1]	Impairment
	Level 1	Level 2	Level 3		
			(In thousands)		
Three months ended September 30, 2017					
Impaired oil and natural gas properties	$ — —	$ —	$ —	$ —	$ —
Three months ended September 30, 2016					
Impaired oil and natural gas properties	$ —	$ —	$ —	$ —	$ —
Nine months ended September 30, 2017					
Impaired oil and natural gas properties	$ — —	$ —	$ —	$ —	$ —
Nine months ended September 30, 2016					
Impaired oil and natural gas properties	$ — —	$ —	$ 3,042	$ 9,817	$ 6,775

[1] Amounts represent value on the dates of assessment.

NOTE 7—CREDIT FACILITY

The Partnership maintains a senior secured revolving credit agreement, as amended (the “Senior Line of Credit”). The Senior Line of Credit has a maximum credit amount of $1.0 billion. The amount of the borrowing base is derived from the value of the Partnership’s oil and natural gas properties as determined by the lender syndicate using pricing assumptions that often differ from the current market for future prices. Drawings on the Senior Line of Credit are used for the acquisition of oil and natural gas properties and for other general business purposes.

Effective April 15, 2016, the borrowing base was $450.0 million. The Partnership's fall 2016 borrowing base redetermination process resulted in an increase in the borrowing base to $500.0 million, which became effective October 31, 2016. Effective April 25, 2017, the borrowing base redetermination resulted in an increase to $550.0 million.

On November 1, 2017, the Partnership amended and restated the credit agreement to extend the maturity thereof for a term of five years, create a swingline facility and make other changes to the hedging and restrictive covenants. There was no change to the borrowing base. The Senior Line of Credit now terminates on November 1, 2022.

Prior to October 31, 2016, borrowings under the Senior Line of Credit bore interest at LIBOR plus a margin between 1.50% and 2.50%, or the Prime Rate plus a margin between 0.50% and 1.50%, with the margin depending on the borrowing base utilization percentage. The Prime Rate was determined to be the higher of the financial institution’s prime rate or the federal funds effective rate plus 0.50% per annum.

Effective October 31, 2016, borrowings under the Senior Line of Credit bore interest at LIBOR plus a margin between 2.00% and 3.00%, or the Prime rate plus a margin between 1.00% and 2.00%, with the margin depending on the borrowing base utilization.

The weighted-average interest rate of the Senior Line of Credit was 3.74% and 3.26% as of September 30, 2017 and December 31, 2016, respectively. Accrued interest is payable at the end of each calendar quarter or at the end of each interest period, unless the interest period is longer than 90 days, in which case interest is payable at the end of every 90-day period. In addition, a commitment fee is payable at the end of each calendar quarter based on either a rate of 0.375% if the borrowing base utilization percentage is less than 50%, or 0.500% per annum if the borrowing base utilization percentage is equal to or greater than 50%. The Senior Line of Credit is secured by substantially all of the Partnership’s producing oil and natural gas assets.

The Senior Line of Credit contains various limitations on future borrowings, leases, hedging, and sales of assets. Additionally, the Senior Line of Credit requires the Partnership to maintain a current ratio of not less than 1.0:1.0 and a ratio of total debt to EBITDAX (Earnings before Interest, Taxes, Depreciation, Amortization, and Exploration) of not more than 3.5:1.0. As of September 30, 2017, the Partnership was in compliance with all financial covenants for the Senior Line of Credit.

The aggregate principal balance outstanding was $362.0 million and $316.0 million at September 30, 2017 and December 31, 2016, respectively. The unused portion of the available borrowings under the Senior Line of Credit was $188.0 million and $184.0 million at September 30, 2017 and December 31, 2016, respectively.

NOTE 8—COMMITMENTS AND CONTINGENCIES

Environmental Matters

The Partnership's business includes activities that are subject to U.S. federal, state, and local environmental regulations with regard to air, land, and water quality and other environmental matters.

The Partnership does not consider the potential remediation costs that could result from issues identified in any environmental site assessments to be significant to the consolidated financial statements, and no provision for potential remediation costs has been made.

Litigation

From time to time, the Partnership is involved in legal actions and claims arising in the ordinary course of business. The Partnership believes existing claims as of September 30, 2017 will be resolved without material adverse effect on the Partnership's financial condition or operations.

NOTE 9—INCENTIVE COMPENSATION

On January 7, 2017, the Compensation Committee of the Board of Directors of the Partnership's general partner (the "Board") approved a special grant of 312,825 restricted common units to Thomas L. Carter, Jr., the President and Chief Executive Officer of the Partnership's general partner. Such restricted common units are subject to limitations on transferability, customary forfeiture provisions, and service-based graded vesting requirements through January 7, 2020.

On January 11, 2017, each non-employee director on the Board, other than Robert E. W. Sinclair, was granted 9,095 fully vested common units for service during 2016. Mr. Sinclair was granted 3,653 fully vested common units for services during 2016 prior to his resignation from the Board. On July 28, 2017, Mr. William Randall, the newly elected member of the Board, was issued 6,426 fully vested common units.

On February 15, 2017, the Compensation Committee of the Board approved a grant of awards to each of the Partnership's executive officers and certain other employees. These awards consisted of 438,067 restricted common units and 438,067 restricted performance units (in the form of phantom units) with distribution equivalent rights. The restricted common units are subject to limitations on transferability, customary forfeiture provisions, and service-based graded vesting requirements through January 7, 2020.

The table below summarizes incentive compensation expense recorded in general and administrative expenses in the consolidated statements of operations for the three and nine months ended September 30, 2017 and 2016, respectively:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Incentive compensation expense	**2017**	**2016**	**2017**	**2016**
	(In thousands)		**(In thousands)**	
Cash—long-term incentive plan	$ 359	$ 580	$ 995	$ 2,990
Equity-based compensation—restricted common and subordinated units	3,364	4,487	10,246	10,420
Equity-based compensation—restricted performance units	3,767	3,066	6,710	11,105
Board of Directors incentive plan	544	428	1,658	1,385
Total incentive compensation expense	$ 8,034	$ 8,561	$ 19,609	$ 25,900

NOTE 10—REDEEMABLE PREFERRED UNITS

The Partnership had 26,426 and 52,691 redeemable preferred units outstanding with a carrying value of $27.1 million and $54.0 million as of September 30, 2017 and December 31, 2016, respectively. The aforementioned amounts included accrued distributions of $0.7 million as of September 30, 2017 and $1.3 million as of December 31, 2016. The redeemable preferred units are classified as mezzanine equity on the consolidated balance sheets since redemption is outside the control of the Partnership. The redeemable preferred units are entitled to an annual distribution of 10% of the outstanding funded capital of the redeemable preferred units, payable on a quarterly basis in arrears.

The redeemable preferred units are convertible into common and subordinated units at any time at the option of the redeemable preferred unitholders. The redeemable preferred units have an adjusted conversion price of $14.2683 and an adjusted conversion rate of 30.3431 common units and 39.7427 subordinated units per redeemable preferred unit, which reflects the reverse split described in Note 1 – Business and Basis of Presentation and the capital restructuring related to the IPO.

The redeemable preferred unitholders can elect to have the Partnership redeem, at face value, all remaining redeemable preferred units as of December 31, 2017, plus any accrued and unpaid distributions. All redeemable preferred units not redeemed as of 2017 year end shall automatically convert to common and subordinated units during the first quarter of 2018.

For the nine months ended September 30, 2017, 19,641 redeemable preferred units were redeemed for $20.1 million, including accrued unpaid yield, and 6,624 redeemable preferred units totaling $6.6 million were converted into 200,996 common units and 263,247 subordinated units as a result of the mandatory conversion subsequent to December 31, 2016. For the year ended December 31, 2016, 6,064 redeemable preferred units totaling $6.1 million were converted into the equivalent of 184,006 common units and 240,986 subordinated units on an adjusted basis.

NOTE 11—EARNINGS PER UNIT

The Partnership applies the two-class method for purposes of calculating earnings per unit ("EPU"). The holders of the Partnership's restricted common and subordinated units have all the rights of a unitholder, including non-forfeitable distribution rights. As participating securities, the restricted common and subordinated units are included in the calculation of basic earnings per unit. For the periods presented, the amount of earnings allocated to these participating units was not material. Net income (loss) attributable to the Partnership is allocated to the Partnership's general partner and the common and subordinated unitholders in proportion to their pro rata ownership after giving effect to distributions, if any, declared during the period. The redeemable preferred units could be converted into 0.8 million common units and 1.0 million subordinated units as of September 30, 2017. At September 30, 2017, if the outstanding redeemable preferred units were converted to common and subordinated units, the effect would be anti-dilutive. The Partnership's restricted performance unit awards are contingently issuable units that are considered in the calculation of diluted EPU. The Partnership assesses the number of units that would be issuable, if any, under the terms of the arrangement if the end of the reporting period were the end of the contingency period. At September 30, 2017, there were no units related to the Partnership's restricted performance unit awards included in the calculation of diluted EPU.

The following table sets forth the computation of basic and diluted earnings per common and subordinated unit:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In thousands, except per unit amounts)		(In thousands, except per unit amounts)	
NET INCOME (LOSS)	$ 22,034	$ 37,535	$ 137,793	$ 27,474
NET (INCOME) LOSS ATTRIBUTABLE TO NONCONTROLLING INTERESTS	20	8	27	15
DISTRIBUTIONS ON REDEEMABLE PREFERRED UNITS	(666)	(1,324)	(2,452)	(4,439)
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON AND SUBORDINATED UNITS	$ 21,388	$ 36,219	$ 135,368	$ 23,050
ALLOCATION OF NET INCOME (LOSS):				
General partner interest	$ —	$ —	$ —	$ —
Common units	16,371	23,114	83,989	24,343
Subordinated units	5,017	13,105	51,379	(1,293)
	$ 21,388	$ 36,219	$ 135,368	$ 23,050
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON AND SUBORDINATED UNIT:				
Per common unit (basic)	$ 0.16	$ 0.24	$ 0.86	$ 0.26
Weighted average common units outstanding (basic)	101,623	95,740	97,777	95,086
Per subordinated unit (basic)	$ 0.05	$ 0.14	$ 0.54	$ (0.01)
Weighted average subordinated units outstanding (basic)	95,388	95,189	95,269	95,125
Per common unit (diluted)	$ 0.16	$ 0.24	$ 0.86	$ 0.26
Weighted average common units outstanding (diluted)	101,623	96,011	97,777	95,619
Per subordinated unit (diluted)	$ 0.05	$ 0.14	$ 0.54	$ (0.01)
Weighted average subordinated units outstanding (diluted)	95,388	95,189	95,269	95,467

NOTE 12—AT-THE-MARKET OFFERING PROGRAM

On May 26, 2017, the Partnership commenced an at-the-market offering program (the "ATM Program") and in connection therewith entered into an Equity Distribution Agreement with Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, and UBS Securities LLC, as Sales Agents (each a "Sales Agent" and collectively the "Sales Agents"). Pursuant to the terms of the ATM Program, the Partnership may sell, from time to time through the Sales Agents, the Partnership's common units representing limited partner interests having an aggregate offering price of up to $100,000,000. Sales of common units, if any, may be made in negotiated transactions or transactions that are deemed to be "at the market" offerings as defined in Rule 415 under the Securities Act of 1933, as amended (the "Securities Act"), including sales made directly on the New York Stock Exchange or sales made to or through a market maker other than on an exchange.

Under the terms of the ATM Program, the Partnership may also sell common units to one or more of the Sales Agents as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to a Sales Agent as principal would be pursuant to the terms of a separate agreement between the Partnership and such Sales Agent.

The Partnership intends to use the net proceeds from any sales pursuant to the ATM Program, after deducting the Sales Agents' commissions and the Partnership's offering expenses, for general partnership purposes, which may include, among other things, repayment of indebtedness outstanding under the Partnership's credit facility.

Common units sold pursuant to the Equity Distribution Agreement are offered and sold pursuant to the Partnership's existing effective shelf-registration statement on Form S-3 (File No. 333-215857), which was declared effective by the Securities and Exchange Commission on February 8, 2017.

The Equity Distribution Agreement contains customary representations, warranties and agreements, indemnification obligations, including for liabilities under the Securities Act, other obligations of the parties and termination provisions.

Through September 30, 2017, the Partnership sold 1.9 million common units under the ATM Program for net proceeds of $31.3 million.

NOTE 13—SUBSEQUENT EVENTS

On November 1, 2017, the Partnership amended and restated its credit agreement, as discussed further in Note 7—Credit Facility.

On November 6, 2017, the Board approved a distribution for the three months ended September 30, 2017 of $0.3125 per common unit and $0.20875 per subordinated unit. Distributions will be payable on November 24, 2017 to unitholders of record at the close of business on November 17, 2017.

Additionally, on November 6, 2017, the Partnership entered into oil and natural gas commodity derivative contracts, as summarized in Note 5—Derivatives and Financial Instruments.

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 unaudited consolidated financial statements and notes thereto presented in this Quarterly Report on Form 10-Q, as well as our audited financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2016. This discussion and analysis contains forward-looking statements that involve risks, uncertainties, and assumptions. Actual results may differ materially from those anticipated in these forward-looking statements as a result of a number of factors, including those set forth under "Cautionary Note Regarding Forward-Looking Statements" and "Part II, Item 1A. Risk Factors."

Unless the context clearly indicates otherwise, references in this Quarterly Report on Form 10-Q to "BSM," the "Partnership," "we," "our," "us," or similar terms for time periods prior to the IPO refer to Black Stone Minerals Company, L.P. and its subsidiaries, the predecessor for accounting purposes. For time periods subsequent to the IPO, these terms refer to Black Stone Minerals, L.P. and its subsidiaries.

Cautionary Note Regarding Forward-Looking Statements

Certain statements and information in this Quarterly Report on Form 10-Q may constitute "forward-looking statements." The words "believe," "expect," "anticipate," "plan," "intend," "foresee," "should," "would," "could," or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Important factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to, those summarized below:

- our ability to execute our business strategies;
- the volatility of realized oil and natural gas prices;
- the level of production on our properties;
- regional supply and demand factors, delays, or interruptions of production;
- our ability to replace our oil and natural gas reserves;
- our ability to identify, complete, and integrate acquisitions;
- general economic, business, or industry conditions;
- competition in the oil and natural gas industry;
- the ability of our operators to obtain capital or financing needed for development and exploration operations;
- title defects in the properties in which we invest;
- the availability or cost of rigs, equipment, raw materials, supplies, oilfield services, or personnel;
- restrictions on the use of water;
- the availability of transportation facilities;

- the ability of our operators to comply with applicable governmental laws and regulations and to obtain permits and governmental approvals;
- federal and state legislative and regulatory initiatives relating to hydraulic fracturing;
- future operating results;
- future cash flows and liquidity, including our ability to generate sufficient cash to pay quarterly distributions;
- exploration and development drilling prospects, inventories, projects, and programs;
- operating hazards faced by our operators;
- the ability of our operators to keep pace with technological advancements; and
- certain factors discussed elsewhere in this filing.

For additional information regarding known material factors that could cause our actual results to differ from our projected results, please see “Risk Factors” in our Annual Report on Form 10-K.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events, or otherwise.

Overview

We are one of the largest owners of oil and natural gas mineral interests in the United States. Our principal business is maximizing the value of our existing portfolio of mineral and royalty assets through active management and expanding our asset base through acquisitions of additional mineral and royalty interests. We maximize value through the marketing of our mineral assets for lease, creative structuring of terms on those leases to encourage and accelerate drilling activity, and selectively participating alongside our lessees on a working-interest basis in low-risk development-drilling opportunities on our interests. Our primary business objective is to grow our reserves, production, and cash generated from operations over the long term, while paying, to the extent practicable, a growing quarterly distribution to our unitholders.

As of September 30, 2017, our mineral and royalty interests were located in 41 states and 64 onshore basins in the continental United States. These non-cost-bearing interests include ownership in approximately 53,000 producing wells. We also own non-operated working interests, largely on our mineral and royalty interests. We recognize oil and natural gas revenue from our mineral and royalty and non-operated working interests in producing wells when the oil and natural gas production from the associated acreage is sold. Our other sources of revenue include mineral lease bonus and delay rentals, which are recognized as revenue according to the terms of the lease agreements.

Recent Developments

Acquisitions

During the first nine months of 2017, we closed numerous acquisitions consisting of various mineral and royalty interests in several Texas counties. In the first quarter of 2017, we acquired mineral and royalty interests in East Texas prospective for the Haynesville and Bossier shales for a total of $17.6 million in cash and $0.2 million in our common units, as well as mineral and royalty interests in the Delaware Basin for $30.8 million in cash and $12.0 million in common units. In the second quarter of 2017, we acquired additional mineral and royalty interests in East Texas for $18.1 million in cash and $45.7 million in our common units, primarily through the acquisition of the Angelina County Lumber Company. In the third quarter of 2017, we acquired additional mineral and royalty interests in East Texas for $22.2 million in cash and $13.7 million in our common units, as well as mineral and royalty interests in the Anadarko Basin for $0.4 million in cash. Additional information regarding acquisitions is contained in Note 4 - Acquisitions and Dispositions to our unaudited consolidated financial statements included herein for further discussion.

At-the-Market Offering Program

In the second quarter of 2017, we commenced an at-the-market offering program (the “ATM Program”) and in connection therewith entered into an Equity Distribution Agreement. The ATM Program permits us from time to time through our Sales Agents to sell our common units having an aggregate offering price of up to $100,000,000. We intend to use the net proceeds from any sales pursuant to the ATM Program, after deducting commissions and offering expenses, for general partnership purposes, which may include, among other things, repayment of indebtedness outstanding under our credit facility. Common units to be sold pursuant to the Equity Distribution Agreement will be offered and sold pursuant to our existing effective shelf-registration statement on Form S-3 (File No. 333-215857), which was declared effective by the Securities and Exchange Commission on February 8, 2017. Proceeds, net of commissions and expenses, of these sales through September 30, 2017 amounted to $31.3 million. See Note 12 - At-the-Market Offering Program to our unaudited consolidated financial statements included herein for further discussion.

Farmout Agreement

On February 21, 2017, we announced that we entered into a farmout agreement with Canaan Resource Partners ("Canaan", and such farmout, the "Canaan Farmout"), which covers certain Haynesville and Bossier shale acreage in San Augustine County, Texas operated by XTO Energy Inc. We have an approximate 50% working interest in the acreage. A total of 18 wells are anticipated to be drilled over an initial phase, beginning with wells spud after January 1, 2017. At its option, Canaan may participate in two additional phases with each phase continuing for the lesser of two years or until 20 wells have been drilled. During the first three phases of the agreement, Canaan will commit on a phase-by-phase basis and fund 80% of our drilling and completion costs and will be assigned 80% of our working interests in such wells (40% working interest on an 8/8ths basis). After the third phase, Canaan can earn 40% of our working interest (20% working interest on an 8/8ths basis) in additional wells drilled in the area by continuing to fund 40% of our costs for those wells on a well-by-well basis. We will receive a base overriding royalty interest (“ORRI”) before payout and an additional ORRI after payout on all wells drilled under the agreement. The execution of this agreement is anticipated to offset our future capital expenditures by approximately $40 to $50 million annually during the term of the agreement.

Business Environment

The information presented below is designed to give a broad overview of the oil and natural gas business environment as it affects us.

Commodity Prices

Oil and natural gas prices have been historically volatile based upon the dynamics of supply and demand. U.S. crude oil and petroleum product markets were significantly disrupted by Hurricane Harvey's landfall in Texas and Louisiana at the end of August. At the peak of disruption, the Energy Information Agency ("EIA") estimates that 3.9 million barrels per day of U.S. Gulf Coast refining capacity was taken offline. Oil transportation capacity in the region was also restricted after the hurricane. According to the EIA, producers also curtailed production in the Eagle Ford region of South Texas; however production declines in that area were offset by growth in other areas of the lower 48 states onshore region. In early to mid-September, the petroleum supply system on the Gulf Coast began to return to service. The EIA reported that lower refinery demand for crude oil in the Gulf Coast region more than offset reductions in crude oil production as a result of the storm, which contributed to lower West Texas Intermediate ("WTI") prices and simultaneously contributed to higher product prices.

Higher crude oil prices in September reflected declining global inventories, thus increasing expectations for global economic and oil demand growth; falling production from the Organization of the Petroleum Exporting countries contributed to global oil inventory withdrawals in 2017. The EIA believes the appearance of strengthening economic conditions could contribute to oil demand growth in 2018. The EIA forecasts that the WTI spot price will average $50.50 per barrel in 2018.

As rising natural gas production is keeping pace with increasing consumption and demand for exports, particularly for liquefied natural gas ("LNG"), the EIA projects a balanced market from the last quarter of 2017 through 2018. The EIA expects LNG export capacity to increase, with LNG exports projected to exceed 3 Bcf per day in 2018. In addition, increased takeaway capacity out of the Marcellus/Utica shale plays, as a result of several new pipeline projects, is anticipated to increase overall production. The EIA estimates that Henry Hub natural gas spot prices will rise from an annual average of $3.03 per MMbtu in 2017 to $3.19 per MMbtu in 2018.

To manage the variability in cash flows associated with the projected sale of our oil and natural gas production, we use various derivative instruments, which have recently consisted exclusively of fixed-price swap contracts.

The following table reflects commodity prices at the end of each quarter presented:

	2017			2016		
Benchmark Prices	**Third Quarter**	**Second Quarter**	**First Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
WTI spot oil price ($/Bbl)	$ 48.18	$ 46.02	$ 50.54	$ 47.72	$ 48.27	$ 36.94
Henry Hub spot natural gas ($/MMBtu)	$ 2.95	$ 2.98	$ 3.13	$ 2.84	$ 2.94	$ 1.98

Source: EIA

Rig Count

As we are the operator of record on only three properties, drilling on our acreage is dependent upon the exploration and production companies that lease our acreage. In addition to drilling plans that we seek from our operators, we also monitor rig counts in an effort to identify existing and future leasing and drilling activity on our acreage.

The following table shows the rig count at the close of each quarter presented:

	2017			2016		
U.S. Rotary Rig Count	**Third Quarter**	**Second Quarter**	**First Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
Oil	750	756	662	425	330	372
Natural gas	189	184	160	96	90	92
Other	1	—	2	1	1	—
Total	940	940	824	522	421	464

Source: Baker Hughes Incorporated

Natural Gas Storage

A substantial portion of our revenue is derived from sales of oil production attributable to our interests; however, the majority of our production is natural gas. Natural gas prices are significantly influenced by storage levels throughout the year. Accordingly, we monitor the natural gas storage reports regularly in the evaluation of our business and its outlook.

Historically, natural gas supply and demand fluctuates on a seasonal basis. From April to October, when the weather is warmer and natural gas demand is lower, natural gas storage levels generally increase. From November to March, storage levels typically decline as utility companies draw natural gas from storage to meet increased heating demand due to colder weather. In order to maintain sufficient storage levels for increased seasonal demand, a portion of natural gas production during the summer months must be used for storage injection. The portion of production used for storage varies from year to year depending on the demand from the previous winter and the demand for electricity used for cooling during the summer months. According to the EIA, injections of natural gas into underground storage exceeded market expectations and historical averages for the first three weeks of September 2017.

The following table shows natural gas storage volumes by region at the close of each quarter presented:

Region	2017 Third Quarter	2017 Second Quarter	2017 First Quarter	2016 Third Quarter	2016 Second Quarter	2016 First Quarter
	(Bcf)					
East	861	564	268	899	632	439
Midwest	989	699	479	1,045	742	555
Mountain	220	187	142	237	198	147
Pacific	311	287	216	318	315	262
South Central	1,127	1,151	946	1,181	1,253	1,065
Total	3,508	2,888	2,051	3,680	3,140	2,468

Source: EIA

How We Evaluate Our Operations

We use a variety of operational and financial measures to assess our performance. Among the measures considered by management are the following:

- volumes of oil and natural gas produced;
- commodity prices including the effect of derivative instruments; and
- Adjusted EBITDA, distributable cash flow, and distributable cash flow after net working interest capital expenditures.

Volumes of Oil and Natural Gas Produced

In order to track and assess the performance of our assets, we monitor and analyze our production volumes from the various basins and plays that comprise our extensive asset base. We also regularly compare projected volumes to actual reported volumes and investigate unexpected variances.

Commodity Prices

Factors Affecting the Sales Price of Oil and Natural Gas

The prices we receive for oil, natural gas, and natural gas liquids ("NGLs") vary by geographical area. The relative prices of these products are determined by the factors affecting global and regional supply and demand dynamics, such as economic conditions, production levels, availability of transportation, weather cycles, and other factors. In addition, realized prices are influenced by product quality and proximity to consuming and refining markets. Any differences between realized prices and NYMEX prices are referred to as differentials. All of our production is derived from properties located in the United States.

- *Oil*. The substantial majority of our oil production is sold at prevailing market prices, which fluctuate in response to many factors that are outside of our control. NYMEX light sweet crude oil, commonly referred to as WTI, is the prevailing domestic oil pricing index. The majority of our oil production is priced at the prevailing market price with the final realized price affected by both quality and location differentials.

  The chemical composition of crude oil plays an important role in its refining and subsequent sale as petroleum products. As a result, variations in chemical composition relative to the benchmark crude oil, usually WTI, will result in price adjustments, which are often referred to as quality differentials. The characteristics that most significantly affect quality differentials include the density of the oil, as characterized by its American Petroleum Institute ("API") gravity, and the presence and concentration of impurities, such as sulfur.

  Location differentials generally result from transportation costs based on the produced oil's proximity to consuming and refining markets and major trading points.

- *Natural Gas.* The NYMEX price quoted at Henry Hub is a widely used benchmark for the pricing of natural gas in the United States. The actual volumetric prices realized from the sale of natural gas differ from the quoted NYMEX price as a result of quality and location differentials.

  Quality differentials result from the heating value of natural gas measured in Btus and the presence of impurities, such as hydrogen sulfide, carbon dioxide, and nitrogen. Natural gas containing ethane and heavier hydrocarbons has a higher Btu value and will realize a higher volumetric price than natural gas which is predominantly methane, which has a lower Btu value. Natural gas with a higher concentration of impurities will realize a lower volumetric price due to the presence of the impurities in the natural gas when sold or the cost of treating the natural gas to meet pipeline quality specifications.

  Natural gas, which currently has a limited global transportation system, is subject to price variances based on local supply and demand conditions and the cost to transport natural gas to end user markets.

Hedging

We use derivative instruments to partially mitigate the impact of commodity price volatility on our cash generated from operations. From time to time, such instruments may include fixed-price swaps, costless collars, and other contractual arrangements. The impact of these derivative instruments could affect the amount of revenue we ultimately realize. Since 2015, we have only entered into fixed-price swap contracts. Under fixed-price swap contracts, a counterparty is required to make a payment to us if the settlement price is less than the swap strike price. Conversely, we are required to make a payment to the counterparty if the settlement price is greater than the swap strike price. We may employ contractual arrangements other than fixed-price swap contracts in the future to mitigate the impact of price fluctuations. If commodity prices decline in the future, our hedging contracts will partially mitigate the effect of lower prices on our future revenue.

Our open oil and natural gas derivative contracts as of September 30, 2017, and as of the date of this filing, are detailed in Note 5 – Derivatives and Financial Instruments to our unaudited consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q. Our credit agreement limits the extent to which we can hedge our future production.

As of September 30, 2017, per the terms of our credit agreement, we were allowed to hedge all of our estimated production from our proved developed producing reserves based on the most recent reserve information provided to our lenders. Under these terms, we hedged approximately 92.5% and 98.7% of our available oil and condensate hedge volumes, respectively, and almost 92.4% and 99% of our available natural gas hedge volumes for the remainder of 2017 and 2018, respectively.

Pursuant to the closing of our Fourth Amended and Restated credit agreement on November 1, 2017, we are allowed to hedge expected production volumes in excess of estimated production from our proved developed reserves. The revised provisions in our credit agreement allow us to hedge certain percentages of future monthly production equal to the lesser of internally forecasted production or the average of reported production for the most recent three months. We are allowed to hedge up to 90% of production for the first 24 months, 70% for months 25 through 36, and 50% for months 37 through 48. Pursuant to our updated hedge provisions, we have hedged approximately 95%, 99%, and 23% of our available oil and condensate hedge volumes for the remainder of 2017, 2018, and 2019, respectively. Also, we have hedged 99%, 99%, and 28% of our available natural gas hedge volumes for the remainder of 2017, 2018, and 2019, respectively.

The Company intends to continuously monitor the production from our assets and the commodity price environment, and will, from time to time, add additional hedges within the percentages described above to remain significantly hedged for the following 12 to 24 months. We do not enter into derivative instruments for speculative purposes.

Non-GAAP Financial Measures

Adjusted EBITDA, distributable cash flow, and distributable cash flow after net working interest capital expenditures are supplemental non-GAAP financial measures used by our management and external users of our financial statements such as investors, research analysts, and others, to assess the financial performance of our assets and our ability to sustain distributions over the long term without regard to financing methods, capital structure, or historical cost basis.

We define Adjusted EBITDA as net income (loss) before interest expense, income taxes and depreciation, depletion, and amortization adjusted for impairment of oil and natural gas properties, accretion of asset retirement obligations, unrealized gains and losses on commodity derivative instruments, and non-cash equity-based compensation. We define distributable cash flow as Adjusted EBITDA plus or minus amounts for certain non-cash operating activities, estimated replacement capital expenditures, cash interest expense, and distributions to noncontrolling interests and preferred unitholders. We define distributable cash flow after net working interest capital expenditures as distributable cash flow less net working interest capital expenditures. Net working interest capital expenditures consist of all capital expenditures related to working interest wells less the recoupment of working interest expenditures under our farmout agreement.

Adjusted EBITDA, distributable cash flow, and distributable cash flow after net working interest capital expenditures should not be considered an alternative to, or more meaningful than, net income (loss), income (loss) from operations, cash flows from operating activities, or any other measure of financial performance presented in accordance with generally accepted accounting principles in the United States ("U.S. GAAP") as measures of our financial performance.

Adjusted EBITDA, distributable cash flow, and distributable cash flow after net working interest capital expenditures have important limitations as analytical tools because they exclude some but not all items that affect net income (loss), the most directly comparable U.S. GAAP financial measure. Our computation of Adjusted EBITDA, distributable cash flow, and distributable cash flow after net working interest capital expenditures may differ from computations of similarly titled measures of other companies.

The following table presents a reconciliation of Adjusted EBITDA, distributable cash flow and distributable cash flow after net working interest capital expenditures to net income (loss), the most directly comparable U.S. GAAP financial measure, for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(Unaudited) (In thousands)			
Net income (loss)	$ 22,034	$ 37,535	$ 137,793	$ 27,474
Adjustments to reconcile to Adjusted EBITDA:				
Depreciation, depletion and amortization	29,204	28,731	84,483	79,654
Interest expense	4,172	2,282	11,660	4,773
Impairment of oil and natural gas properties	—	—	—	6,775
Accretion of asset retirement obligations	260	206	760	680
Equity-based compensation[1]	7,675	7,981	18,614	33,120
Unrealized (gain) loss on commodity derivative instruments	14,320	(2,511)	(23,048)	51,515
Adjusted EBITDA	77,665	74,224	230,262	203,991
Adjustments to reconcile to distributable cash flow:				
Change in deferred revenue	(701)	(396)	(1,670)	(175)
Cash interest expense	(3,946)	(2,083)	(10,999)	(4,179)
(Gain) loss on sales of assets, net	—	—	(931)	(4,772)
Estimated replacement capital expenditures[2]	(3,250)	(3,750)	(10,250)	(7,500)
Cash paid to noncontrolling interests	(24)	(29)	(90)	(83)
Redeemable preferred unit distributions	(666)	(1,324)	(2,452)	(4,439)
Distributable Cash Flow	69,078	66,642	203,870	182,843
Net working interest capital expenditures	(1,793)	(26,329)	(34,088)	(63,039)
Distributable cash flow after net working interest capital expenditures	$ 67,285	$ 40,313	$ 169,782	$ 119,804

[1] On April 25, 2016, the Compensation Committee of the Board approved a resolution to change the settlement feature of certain employee long-term incentive compensation plans from cash to equity. As a result of the modification, $10.1 million of cash-settled liabilities were reclassified to equity-settled liabilities during the second quarter of 2016.

[2] On August 3, 2016, the Board of Directors of our general partner (the "Board") established a replacement capital expenditure estimate of $15.0 million for the period of April 1, 2016 to March 31, 2017. There was no established estimate of replacement capital expenditures prior to this period. On June 8, 2017, the Board established a replacement capital expenditure estimate of $13.0 million for the period of April 1, 2017 to March 31, 2018.

Results of Operations

Three Months Ended September 30, 2017 Compared to Three Months Ended September 30, 2016

The following table shows our production, revenues, pricing, and expenses for the periods presented:

	Three Months Ended September 30,			
	2017	2016	Variance	
	(Unaudited) (Dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)	911	1,015	(104)	(10.2)%
Natural gas (MMcf)[1]	14,974	13,207	1,767	13.4 %
Equivalents (MBoe)	3,407	3,216	191	5.9 %
Revenue:				
Oil and condensate sales	$ 41,361	$ 42,780	$ (1,419)	(3.3)%
Natural gas and natural gas liquids sales[1]	45,047	38,986	6,061	15.5 %
Gain (loss) on commodity derivative instruments	(9,341)	7,813	(17,154)	(219.6)%
Lease bonus and other income	12,044	9,592	2,452	25.6 %
Total revenue	$ 89,111	$ 99,171	$ (10,060)	(10.1)%
Realized prices:				
Oil and condensate ($/Bbl)	$ 45.39	$ 42.15	$ 3.24	7.7 %
Natural gas ($/Mcf)[1]	3.01	2.95	0.06	2.0 %
Equivalents ($/Boe)	$ 25.36	$ 25.42	$ (0.06)	(0.2)%
Operating expenses:				
Lease operating expense	$ 4,569	$ 5,007	$ (438)	(8.7)%
Production costs and ad valorem taxes	11,549	9,228	2,321	25.2 %
Exploration expense	8	6	2	33.3 %
Depreciation, depletion, and amortization	29,204	28,731	473	1.6 %
Impairment of oil and natural gas properties	—	—	—	—
General and administrative	17,305	16,677	628	3.8 %

[1] As a mineral-and-royalty-interest owner, we are often provided insufficient and inconsistent data on NGL volumes by our operators. As a result, we are unable to reliably determine the total volumes of NGLs associated with the production of natural gas on our acreage. Accordingly, no NGL volumes are included in our reported production; however, revenue attributable to NGLs is included in our natural gas revenue and our calculation of realized prices for natural gas.

Revenue

Total revenue for the quarter ended September 30, 2017 decreased compared to the quarter ended September 30, 2016. Production for the quarter ended September 30, 2017 averaged 37.0 MBoe per day, an increase of 2.0 MBoe per day compared to the corresponding period in 2016. The decrease in total revenue is primarily due to losses on commodity derivative instruments, partially offset by higher natural gas and NGL sales and lease bonus revenue as compared to the corresponding period in 2016.

Oil and condensate sales. Oil and condensate sales during the period were modestly lower than the third quarter of 2016 primarily due to lower production volumes from our Bakken assets. Our mineral-and-royalty-interest oil and condensate volumes decreased 5.3% in the third quarter of 2017 relative to the corresponding period in 2016 primarily as a result of the Bakken decrease. Our mineral-and-royalty-interest oil and condensate volumes accounted for 78.0% and 74.0% of total oil and condensate volumes for the quarters ended September 30, 2017 and 2016, respectively. The decrease in production volumes was partially offset by an increase in commodity prices between the comparative periods.

Natural gas and natural gas liquids sales. Natural gas and NGL sales increased for the quarter ended September 30, 2017 as compared to the same period for 2016. Higher commodity prices and higher production volumes, largely driven by new wells in the Haynesville play, were primarily responsible for the increase in our natural gas and NGL revenues. Mineral-and-royalty-interest production accounted for 50.6% and 58.4% of our natural gas volumes for the quarters ended September 30, 2017 and 2016, respectively.

Gain (loss) on commodity derivative instruments. During the third quarter of 2017, we recognized $9.5 million of losses from oil commodity contracts, which included cash received of $4.0 million, compared to recognized gains of $3.7 million in the same period of 2016. During the third quarter of 2017, we recognized $0.2 million of gains from natural gas commodity contracts, which included cash received of $1.0 million, compared to recognized gains of $4.1 million in the same period of 2016.

Lease bonus and other income. When we lease our mineral interests, we generally receive an upfront cash payment, or a lease bonus. Leasing activity in the Anadarko and Delaware Basins made up the majority of lease bonus in the third quarter of 2017, while a substantial portion of third quarter 2016 activity came from the Wolfcamp and Marcellus trends.

Operating and Other Expenses

Lease operating expense. Lease operating expense includes normally recurring expenses associated with our non-operated working interests necessary to produce hydrocarbons from our oil and natural gas wells, as well as certain nonrecurring expenses, such as well repairs. Lease operating expense decreased for the quarter ended September 30, 2017 as compared to the same period in 2016, primarily due to decreased operating costs in fields reaching economic limits and fewer remedial projects initiated by our operators. These cost decreases were partially offset by increased operating costs in the Haynesville play.

Production costs and ad valorem taxes. Production taxes include statutory amounts deducted from our production revenues by various state taxing entities. Depending on the regulations of the states where the production originates, these taxes may be based on a percentage of the realized value or a fixed amount per production unit. This category also includes the costs to process and transport our production to applicable sales points. Ad valorem taxes are jurisdictional taxes levied on the value of oil and natural gas minerals and reserves. Rates, methods of calculating property values, and timing of payments vary between taxing authorities. For the quarter ended September 30, 2017, production costs and ad valorem taxes increased from the quarter ended September 30, 2016, generally as a result of higher oil and condensate and natural gas prices and natural gas production volumes. In addition, the 2016 amount includes $2.7 million of lawsuit settlement proceeds related to improper cost deductions.

Exploration expense. Exploration expense typically consists of dry-hole expenses, delay rentals, and geological and geophysical costs, including seismic costs, and is expensed as incurred under the successful efforts method of accounting. Exploration expense increased slightly for the three months ended September 30, 2017, as compared to the same period in 2016. The 2017 and 2016 expense represents delay rental costs incurred to extend working interest leases beyond the original lease term.

Depreciation, depletion, and amortization. Depletion is an estimate of the amount of cost basis of oil and natural gas properties attributable to the volume of hydrocarbons extracted during a period, calculated on a units-of-production basis. Estimates of proved developed producing reserves are a major component of the calculation of depletion. We adjust our depletion rates semi-annually based upon mid-year and year-end reserve reports, except when circumstances indicate that there has been a significant change in reserves or costs. Depreciation, depletion, and amortization increased slightly for the quarter ended September 30, 2017 as compared to the same period in 2016, primarily due to the impact of higher production partially offset by lower depletion rates.

Impairment of oil and natural gas properties. Individual categories of oil and natural gas properties are assessed periodically to determine if the net book value for these properties has been impaired. Management periodically conducts an in-depth evaluation of the carrying amounts of property acquisitions, successful exploratory wells, development activity, undeveloped leasehold, and mineral interests to identify impairments. There were no impairments for the quarters ended September 30, 2017 or 2016.

General and administrative. General and administrative expenses are costs not directly associated with the production of oil and natural gas and includes expenses such as the cost of employee salaries and related benefits, office expenses, and fees for professional services. For the quarter ended September 30, 2017, general and administrative expenses increased as compared to the same period in 2016, primarily driven by brokerage fees associated with higher acquisition activity as compared to the corresponding period in 2016.

Interest expense. Interest expense was higher in the third quarter of 2017 due to increased borrowings under our credit facility. Average outstanding borrowings during the third quarter of 2017 were higher than the third quarter of 2016 due to funding of acquisitions in 2017 and 2016, common unit repurchases in 2016, and redemptions associated with our preferred units.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

The following table shows our production, revenues, pricing, and expenses for the periods presented:

	Nine Months Ended September 30,			
	2017	2016	Variance	
	(Unaudited) (Dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)	2,597	2,848	(251)	(8.8)%
Natural gas (MMcf)[1]	44,459	36,014	8,445	23.4 %
Equivalents (MBoe)	10,007	8,850	1,157	13.1 %
Revenue:				
Oil and condensate sales	$ 119,097	$ 104,581	$ 14,516	13.9 %
Natural gas and natural gas liquids sales[1]	142,651	85,706	56,945	66.4 %
Gain (loss) on commodity derivative instruments	35,387	(12,295)	47,682	(387.8)%
Lease bonus and other income	37,082	26,129	10,953	41.9 %
Total revenue	$ 334,217	$ 204,121	$ 130,096	63.7 %
Realized prices:				
Oil and condensate ($/Bbl)	$ 45.87	$ 36.72	$ 9.15	24.9 %
Natural gas ($/Mcf)[1]	3.21	2.38	0.83	34.9 %
Equivalents ($/Boe)	$ 26.16	$ 21.50	$ 4.66	21.7 %
Operating expenses:				
Lease operating expense	$ 12,906	$ 14,179	$ (1,273)	(9.0)%
Production costs and ad valorem taxes	35,314	23,301	12,013	51.6 %
Exploration expense	616	643	(27)	(4.2)%
Depreciation, depletion, and amortization	84,483	79,654	4,829	6.1 %
Impairment of oil and natural gas properties	—	6,775	(6,775)	(100.0)%
General and administrative	51,998	52,213	(215)	(0.4)%

1 As a mineral-and-royalty-interest owner, we are often provided insufficient and inconsistent data on NGL volumes by our operators. As a result, we are unable to reliably determine the total volumes of NGLs associated with the production of natural gas on our acreage. Accordingly, no NGL volumes are included in our reported production; however, revenue attributable to NGLs is included in our natural gas revenue and our calculation of realized prices for natural gas.

Revenue

Total revenues for the nine months ended September 30, 2017 increased compared to the nine months ended September 30, 2016. Production for the nine months ended September 30, 2017 averaged 36.7 MBoe per day, an increase of 4.4 MBoe per day, compared to the corresponding period in 2016. The increase in total revenue from the corresponding prior period is primarily due to higher realized commodity prices and production volumes, an increase in revenue from our commodity derivative instruments, and higher lease bonus and other income.

Oil and condensate sales. Oil and condensate sales during the nine months ended September 30, 2017 were higher than the corresponding period in 2016 primarily due to higher realized prices, partially offset by a slight decrease in production volumes between comparative periods. Our mineral-and-royalty-interest oil and condensate volumes accounted for 81.3% and 77.2% of total oil and condensate volumes for the nine months ended September 30, 2017 and 2016, respectively. Our mineral-and-royalty-interest oil and condensate volumes decreased 3.9% for the nine months ended September 30, 2017 relative to the corresponding period in 2016, primarily driven by production decreases in the Eagle Ford Shale play due to outages caused by Hurricane Harvey. Our working-interest oil and condensate volumes decreased by 25.5% to 1.8 MBbls per day during the nine months ended September 30, 2017 as compared to the same period in 2016 primarily due to decreased activity in the Bakken play.

Natural gas and natural gas liquids sales. Natural gas and NGL sales increased for the nine months ended September 30, 2017 as compared to the same period for 2016 driven by an increase in production volumes primarily from new wells in the Haynesville/Bossier and Wilcox plays combined with an increase in realized natural gas and NGL prices. Mineral-and-royalty-interest production accounted for 49.7% and 60.7% of our natural gas volumes for the nine months ended September 30, 2017 and 2016, respectively.

Gain (loss) on commodity derivative instruments. During the nine months ended September 30, 2017, we recognized an $18.3 million gain on our oil commodity contracts, which included $10.7 million in cash received, compared to a recognized loss of $8.9 million in the same period of 2016. During the first nine months of 2017, we recognized $17.1 million of gains from natural gas commodity contracts, which included $1.7 million of cash received, compared to a recognized loss of $3.4 million in the same period of 2016.

Lease bonus and other income. Lease bonus and other income increased for the nine months ended September 30, 2017 as compared to the same period in 2016. During the nine months ended September 30, 2017, we successfully closed several significant lease transactions in the Austin Chalk, Bakken/Three Forks, Haynesville/Bossier and Canyon Lime plays, as well as the Anadarko and Permian Basins, compared to the majority of 2016 activity which came from the Wolfcamp, Austin Chalk, and Marcellus plays.

Operating and Other Expenses

Lease operating expense. Lease operating expense decreased for the nine months ended September 30, 2017 as compared to the same period in 2016, primarily due to decreased operating costs in fields reaching economic limits and fewer remedial projects initiated by our operators. These cost decreases were partially offset by increased operating costs in the Haynesville play.

Production costs and ad valorem taxes. For the nine months ended September 30, 2017, production costs and ad valorem taxes increased from the nine months ended September 30, 2016, generally as a result of higher commodity prices and natural gas production volumes. In addition, the 2016 amount includes $2.7 million of lawsuit settlement proceeds related to improper cost deductions.

Exploration expense. Exploration expense decreased for the nine months ended September 30, 2017 as compared to the same period in 2016. Exploration expense for the nine months ended September 30, 2017 represents costs incurred to acquire 3-D seismic information, related to our mineral and royalty interests, from a third-party service provider.

Depreciation, depletion, and amortization. Depreciation, depletion, and amortization increased for the nine months ended September 30, 2017 as compared to the same period in 2016, primarily due to higher production partially offset by lower depletion rates.

Impairment of oil and natural gas properties. Impairments totaled $6.8 million for the nine months ended September 30, 2016 primarily due to changes in reserve values resulting from declines in future expected realized net cash flows.

General and administrative. For the nine months ended September 30, 2017, general and administrative expenses decreased as compared to the same period in 2016 due to lower costs attributable to our long-term incentive plans.

Interest expense. Interest expense increased due to higher average outstanding borrowings under our credit facility. Average outstanding borrowings during the first nine months of 2017 were higher than the nine months ended September 30, 2016, primarily due to funding of acquisitions, common unit repurchases in 2016, and redemptions associated with our preferred units in 2017.

Liquidity and Capital Resources

Overview

Our primary sources of liquidity are cash generated from operations, borrowings under our credit facility, and proceeds from the issuance of equity. Our primary uses of cash are for distributions to our unitholders and for investing in our business, specifically the acquisition of mineral and royalty interests and our selective participation on a non-operated working-interest basis in the development of our oil and natural gas properties.

We intend to finance our future acquisitions with cash generated from operations, borrowings from our credit facility, and proceeds from any future issuances of equity and debt. Over the long-term, we intend to finance our working-interest capital needs with internally-generated cash flows, although at times we may fund a portion of these expenditures through external financing sources such as borrowings under our credit facility. Replacement capital expenditures are expenditures necessary to replace our existing oil and natural gas reserves or otherwise maintain our asset base over the long-term. Like a number of other master limited partnerships, we are required by our partnership agreement to retain cash from our operations in an amount equal to our estimated replacement capital requirements. The Board of Directors of our general partner (the "Board") established a replacement capital expenditure estimate of $15.0 million for the period of April 1, 2016 to March 31, 2017. On June 8, 2017, the Board established a replacement capital expenditure estimate of $13.0 million for the period of April 1, 2017 to March 31, 2018.

Cash Flows

The following table shows our cash flows for the periods presented:

	Nine Months Ended September 30,	
	2017	**2016**
	(Unaudited) (In thousands)	
Cash flows provided by operating activities	$ 211,666	$ 141,559
Cash flows used in investing activities	(116,482)	(203,760)
Cash flows provided by (used in) financing activities	(96,045)	53,816

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Operating Activities. Our operating cash flows are dependent, in large part, on our production, realized commodity prices, derivative settlements, lease bonus revenue, and operating expenses. Our cash flows from operations increased from $141.6 million for the nine months ended September 30, 2016 to $211.7 million for the nine months ended September 30, 2017. The increase was primarily due to increased commodity revenue driven by higher oil and natural gas sales, an increase in lease bonus and other income, as well as changes in working capital.

Investing Activities. Net cash used in investing activities decreased by $87.3 million in the first nine months of 2017 as compared to the corresponding period in 2016 primarily due to the cash portion of 2017 mineral and property acquisitions being lower than the cash portion of 2016 mineral and property acquisitions during the first nine months of 2016. Lower capital expenditures for our working interest properties also contributed to the overall decrease in investing activities.

Financing Activities. Cash flows used in financing activities for the nine months ended September 30, 2017 were primarily driven by $142.6 million of distributions to common and subordinated unitholders, distributions to redeemable preferred unitholders of $3.1 million, redemptions of redeemable preferred units of $19.6 million, and repurchases of common and subordinated units of $7.8 million, which were partially offset by net borrowings on our credit facility of $46.0 million and proceeds from the issuance of common units pursuant to the ATM Program of $31.3 million.

Capital Expenditures

Our 2017 drilling expenditures, net of farmout reimbursements, are expected to be between $50 million to $60 million, with almost our entire drilling capital budget allocated to the Haynesville/Bossier play. Due to the timing of cash calls and invoices received from the operators of our Haynesville/Bossier properties, cash payments for our share of drilling and completion activities may vary materially from quarter to quarter. Accordingly, a portion of our 2017 capital budget may ultimately be paid during the first half of 2018.

On February 16, 2017, we entered into a farmout agreement covering our working interests within an approximate 34,000-acre block in San Augustine County, Texas, which will reduce our future capital requirements and will generate additional royalty income.

During the nine months ended September 30, 2017, we incurred $41.4 million related to drilling and completion costs, primarily in the Haynesville/Bossier play, and completed mineral and royalty interests acquisitions for $160.7 million in cash and equity. See Note 4 – Acquisitions and Dispositions to our unaudited consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for further discussion.

Credit Facility

On January 23, 2015, we amended and restated our $1.0 billion senior secured revolving credit agreement. Under this credit facility, the commitment of the lenders equals the lesser of the aggregate maximum credit amounts of the lenders and the borrowing base, which is determined based on the lenders' estimated value of our oil and natural gas properties. On October 28, 2015, the third amended and restated credit facility was further amended to extend the term of the agreement from February 3, 2017 to February 4, 2019. Borrowings under the third amended and restated credit facility may be used for the acquisition of properties, cash distributions, and other general corporate purposes. Our regular, semi-annual borrowing base redetermination process resulted in a decrease of the borrowing base from $550.0 million to $450.0 million, effective April 15, 2016. Our fall 2016 borrowing base redetermination process resulted in an increase in the borrowing base to $500.0 million, which became effective October 31, 2016. Effective April 25, 2017, the borrowing base redetermination resulted in an increase to $550.0 million. On November 1, 2017, we amended and restated the credit agreement again to extend the maturity date thereof for a term of five years, create a swingline facility and make other changes to the hedging and restrictive covenants. There was no change to the borrowing base. Our credit facility now terminates on November 1, 2022. As of September 30, 2017, we had outstanding borrowings of $362.0 million at a weighted-average interest rate of 3.74%.

The borrowing base under both the third amended and restated credit agreement and the fourth amended and restated credit agreement is redetermined semi-annually, typically in April and October of each year, by the administrative agent, taking into consideration the estimated loan value of our oil and natural gas properties consistent with the administrative agent's normal lending criteria. The administrative agent's proposed redetermined borrowing base must be approved by all lenders to increase our existing borrowing base, and by two-thirds of the lenders to maintain or decrease our existing borrowing base. In addition, we and the lenders (at the election of two-thirds of the lenders) each have discretion to have the borrowing base redetermined once between scheduled redeterminations. Under the fourth amended and restated credit agreement, we additionally have the right to request a redetermination following acquisition of oil and natural gas properties in excess of 10% of the value of the borrowing base immediately prior to such acquisition.

Outstanding borrowings under the third amended and restated credit agreement and the fourth amended and restated credit agreement bear interest at a floating rate elected by us equal to an alternative base rate (which is equal to the greatest of the Prime rate, the Federal Funds effective rate plus 0.50%, or 1-month LIBOR plus 1.00%) or LIBOR, in each case, plus the applicable margin. Through October 2016, the applicable margin ranged from 0.50% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of borrowings outstanding in relation to the borrowing base. Subsequent to the closing of our fall redetermination on October 31, 2016, the applicable margin ranges from 1.00% to 2.00% in the case of the alternative base rate and from 2.00% to 3.00% in the case of LIBOR, depending on the borrowings outstanding in relation to the borrowing base.

We are obligated to pay a quarterly commitment fee ranging from a 0.375% to 0.500% annualized rate on the unused portion of the borrowing base, depending on the amount of the borrowings outstanding in relation to the borrowing base. Principal may be optionally repaid from time to time without premium or penalty, other than customary LIBOR breakage, and is required to be paid (a) if the amount outstanding exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise, in some cases subject to a cure period, or (b) at the maturity date. Under both the third amended and restated credit agreement and the fourth amended and restated credit agreement, our credit facility is secured by liens on substantially all of our producing properties.

Before and after the amendment and restatement that took place on November 1, 2017, our credit agreement contains various affirmative, negative, and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates, and entering into certain swap agreements, as well as require the maintenance of certain financial ratios. The credit agreement contains two financial covenants: total debt to EBITDAX of 3.5:1.0 or less and a modified current ratio of 1.0:1.0 or greater as defined in the credit agreement. Distributions are not permitted if there is a default under the credit agreement (including due to a failure to satisfy one of the financial covenants) or during any time that our borrowing base is lower than the loans outstanding under the credit agreement. The lenders have the right to accelerate all of the indebtedness under the credit agreement upon the occurrence and during the continuance of any event of default, and the credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy, and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods. As of September 30, 2017, we were in compliance with all debt covenants.

Contractual Obligations

As of September 30, 2017, there have been no material changes to our contractual obligations previously disclosed in our 2016 Annual Report on Form 10-K.

Off-Balance Sheet Arrangements

As of September 30, 2017, we did not have any material off-balance sheet arrangements.

Critical Accounting Policies and Related Estimates

As of September 30, 2017, there have been no significant changes to our critical accounting policies and related estimates previously disclosed in our 2016 Annual Report on Form 10-K.

New and Revised Financial Accounting Standards

The effects of new accounting pronouncements are discussed in the notes to our unaudited consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

Our major market risk exposure is the pricing of oil, natural gas, and natural gas liquids produced by our operators. Realized prices are primarily driven by the prevailing global prices for oil and prices for natural gas and NGLs in the United States. Prices for oil, natural gas, and natural gas liquids have been volatile for several years, and we expect this unpredictability to continue in the future. The prices that our operators receive for production depend on many factors outside of our or their control. To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we use commodity derivative instruments to reduce our exposure to price volatility of oil and natural gas. The counterparties to the contracts are unrelated third parties. The contracts settle monthly in cash based on a designated floating price. The designated floating price is based on the NYMEX benchmark for oil and natural gas. We have not designated any of our contracts as fair value or cash flow hedges. Accordingly, the changes in fair value of the contracts are included in net income in the period of the change. See Note 5 – Derivatives and Financial Instruments and Note 6 – Fair Value Measurement to the unaudited consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for additional information.

Commodity prices have declined in recent years. To estimate the effect lower prices would have on our reserves, we applied a 10% discount to the SEC commodity pricing for the twelve months ended September 30, 2017. Applying this discount results in an approximate 1.6% reduction of proved reserve volumes as compared to the undiscounted September 30, 2017 SEC pricing scenario.

Counterparty and Customer Credit Risk

Our derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require our counterparties to our derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as we deem appropriate. This evaluation includes reviewing a counterparty's credit rating and latest financial information. As of September 30, 2017, we had nine counterparties, all of which are rated Baa1 or better by Moody's. Seven of our counterparties are lenders under our credit facility.

Our principal exposure to credit risk results from receivables generated by the production activities of our operators. The inability or failure of our significant operators to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. However, we believe the credit risk associated with our operators and customers is acceptable.

Interest Rate Risk

We have exposure to changes in interest rates on our indebtedness. As of September 30, 2017, we had $362.0 million of outstanding borrowings under our credit facility, bearing interest at a weighted-average interest rate of 3.74%. The impact of a 1% increase in the interest rate on this amount of debt would have resulted in an increase in interest expense, and a corresponding decrease in our results of operations, of $2.7 million for the nine months ended September 30, 2017, assuming that our indebtedness remained constant throughout the period. We may use certain derivative instruments to hedge our exposure to variable interest rates in the future, but we do not currently have any interest rate hedges in place.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (the "Exchange Act"), we have evaluated, under the supervision and with the participation of management of our general partner, including our general partner's principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report on Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our general partner's principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our general partner's principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of September 30, 2017.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended September 30, 2017 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

Due to the nature of our business, we are, from time to time, involved in routine litigation or subject to disputes or claims related to our business activities. In the opinion of our management, none of the pending litigation, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

Item 1A. Risk Factors

In addition to the other information set forth in this report, readers should carefully consider the risks under the heading “Risk Factors” in our 2016 Annual Report on Form 10-K. There has been no material change in our risk factors from those described in our 2016 Annual Report on Form 10-K. These risks are not the only risks that we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may materially adversely affect our business, financial condition or results of operations.

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

Recent Sales of Unregistered Securities

On August 15, 2017, August 16, 2017, August 17, 2017, September 1, 2017, September 13, 2017, and September 28, 2017, we closed on acquisitions of certain mineral interests using, in the aggregate, 816,428 common units valued at approximately $13.7 million to fund a portion of the total consideration.

The issuances of the common units were made in reliance upon an exemption from the registration requirements of the Securities Act of 1933, as amended, pursuant to Rule 506(c) of Regulation D thereunder. The investors are "accredited investors" (as defined in Regulation D), the investors acquired the common units for investment purposes only and not for resale, and the Partnership took appropriate measures to restrict the transfer of the common units issued and verify the accredited investor status of the investors.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

None.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Black Stone Minerals, L.P. (incorporated herein by reference to Exhibit 3.1 to Black Stone Minerals, L.P.'s Registration Statement on Form S-1 filed on March 19, 2015 (SEC File No. 333-202875)).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Black Stone Minerals, L.P. (incorporated herein by reference to Exhibit 3.2 to Black Stone Minerals, L.P.'s Registration Statement on Form S-1 filed on March 19, 2015 (SEC File No. 333-202875)).
3.3	First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated May 6, 2015, by and among Black Stone Minerals GP, L.L.C. and Black Stone Minerals Company, L.P., as amended by Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P. dated as of April 15, 2016 (incorporated herein by reference to Exhibit 3.2 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on April 19, 2016 (SEC File No. 001-37362)).
10.1	Fourth Amended and Restated Credit Agreement, among Black Stone Minerals Company, L.P., as Borrower, Black Stone Minerals, L.P., as Parent MLP, Wells Fargo Bank, National Association, as Administrative Agent, Bank of America, N.A. and Compass Bank, as Co-Syndication Agents, ZB Bank, N.A. DBA and Amegy Bank National Association, as Documentation Agent, and the lenders signatory thereto, dated as of November 1, 2017 (incorporated herein by reference to Exhibit 10.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on November 6, 2017 (SEC File No. 001-37362)).
*31.1	Certification of Chief Executive Officer of Black Stone Minerals, L.P. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31.2	Certification of Chief Financial Officer of Black Stone Minerals, L.P. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*32.1	Certification of Chief Executive Officer and Chief Financial Officer of Black Stone Minerals, L.P. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*101.INS	XBRL Instance Document
*101.SCH	XBRL Schema Document
*101.CAL	XBRL Calculation Linkbase Document
*101.LAB	XBRL Label Linkbase Document
*101.PRE	XBRL Presentation Linkbase Document
*101.DEF	XBRL Definition Linkbase Document

* Filed or furnished 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.

		BLACK STONE MINERALS, L.P.
	By:	Black Stone Minerals GP, L.L.C., its general partner
Date: November 7, 2017	By:	/s/ Thomas L. Carter, Jr.
		Thomas L. Carter, Jr. President and Chief Executive Officer (Principal Executive Officer)
Date: November 7, 2017	By:	/s/ Jeffrey P. Wood
		Jeffrey P. Wood Senior Vice President and Chief Financial Officer (Principal Financial Officer)

Exhibit 31.1

Certification of Chief Executive Officer
pursuant to Rule 13a-14(a) and Rule 15d-14(a)
of the Securities Exchange Act OF 1934, as amended

I, Thomas L. Carter, Jr., certify that:

1. I have reviewed this report on Form 10-Q of Black Stone Minerals, L.P. (the “registrant”);

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 officers 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 officers 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.

Date: November 7, 2017	/s/ Thomas L. Carter, Jr.
	Thomas L. Carter, Jr.
	President and Chief Executive Officer
	Black Stone Minerals GP, L.L.C., the general partner of Black Stone Minerals, L.P.

Exhibit 31.2

Certification of Chief Financial Officer
pursuant to Rule 13a-14(a) and Rule 15d-14(a)
of the Securities Exchange Act OF 1934, as amended

I, Jeffrey P. Wood, certify that:

1. I have reviewed this report on Form 10-Q of Black Stone Minerals, L.P. (the "registrant");

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 officers 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 officers 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.

Date: November 7, 2017	/s/ Jeffrey P. Wood
	Jeffrey P. Wood
	Senior Vice President and Chief Financial Officer
	Black Stone Minerals GP, L.L.C., the general partner of Black Stone Minerals, L.P.

Exhibit 32.1

Certification of
Chief Executive Officer and Chief Financial Officer
under Section 906 of the
Sarbanes Oxley Act of 2002, 18 U.S.C. § 1350

In connection with the report on Form 10-Q of Black Stone Minerals, L.P. (the "Partnership"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Thomas L. Carter, Jr., Chief Executive Officer of the Partnership, and Jeffrey P. Wood, Chief Financial Officer of the Partnership, each certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: November 7, 2017	/s/ Thomas L. Carter, Jr.
	Thomas L. Carter, Jr. President and Chief Executive Officer Black Stone Minerals GP, L.L.C., the general partner of Black Stone Minerals, L.P.
Date: November 7, 2017	/s/ Jeffrey P. Wood
	Jeffrey P. Wood Senior Vice President and Chief Financial Officer Black Stone Minerals GP, L.L.C., the general partner of Black Stone Minerals, L.P.