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, 2019

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)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Units Representing Limited Partner Interests	BSM	New York Stock Exchange

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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit 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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	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 October 30, 2019, there were 205,959,790 common units and 14,711,219 Series B cumulative convertible 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, 2019	December 31, 2018
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 1,966	$ 5,414
Accounts receivable	84,842	113,148
Commodity derivative assets	33,054	37,970
Prepaid expenses and other current assets	1,472	1,001
TOTAL CURRENT ASSETS	121,334	157,533
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, at cost, using the successful efforts method of accounting, includes unproved properties of $1,091,660 and $1,063,883 at September 30, 2019 and December 31, 2018, respectively	3,403,485	3,441,188
Accumulated depreciation, depletion, amortization, and impairment	(1,948,866)	(1,865,692)
Oil and natural gas properties, net	1,454,619	1,575,496
Other property and equipment, net of accumulated depreciation of $11,450 and $11,048 at September 30, 2019 and December 31, 2018, respectively	2,435	385
NET PROPERTY AND EQUIPMENT	1,457,054	1,575,881
DEFERRED CHARGES AND OTHER LONG-TERM ASSETS	17,425	16,710
TOTAL ASSETS	$ 1,595,813	$ 1,750,124
LIABILITIES, MEZZANINE EQUITY, AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 4,574	$ 4,149
Accrued liabilities	17,384	60,089
Other current liabilities	1,058	528
TOTAL CURRENT LIABILITIES	23,016	64,766
LONG–TERM LIABILITIES		
Credit facility	413,000	410,000
Accrued incentive compensation	1,750	1,813
Commodity derivative liabilities	—	—
Asset retirement obligations	15,584	14,948
Other long-term liabilities	6,781	55,973
TOTAL LIABILITIES	460,131	547,500
COMMITMENTS AND CONTINGENCIES (Note 8)		
MEZZANINE EQUITY		
Partners' equity – Series B cumulative convertible preferred units, 14,711 units outstanding at September 30, 2019 and December 31, 2018	298,361	298,361
EQUITY		
Partners' equity – general partner interest	—	—
Partners' equity – common units, 205,952 and 108,363 units outstanding at September 30, 2019 and December 31, 2018, respectively	837,321	714,823
Partners' equity – subordinated units, zero and 96,329 units outstanding at September 30, 2019 and December 31, 2018, respectively	—	189,440
TOTAL EQUITY	837,321	904,263
TOTAL LIABILITIES, MEZZANINE EQUITY, AND EQUITY	$ 1,595,813	$ 1,750,124

The accompanying notes are an integral part of these unaudited 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,		Nine Months Ended September 30,	
	2019	2018	2019	2018
REVENUE				
Oil and condensate sales	$ 68,255	$ 82,712	$ 200,031	$ 232,920
Natural gas and natural gas liquids sales	41,340	63,080	156,622	170,179
Lease bonus and other income	3,484	12,440	15,846	28,616
Revenue from contracts with customers	113,079	158,232	372,499	431,715
Gain (loss) on commodity derivative instruments	24,290	(18,514)	12,294	(68,194)
TOTAL REVENUE	137,369	139,718	384,793	363,521
OPERATING (INCOME) EXPENSE				
Lease operating expense	4,356	4,229	13,497	12,767
Production costs and ad valorem taxes	15,877	17,641	44,919	46,939
Exploration expense	64	34	372	6,782
Depreciation, depletion, and amortization	27,375	29,273	84,933	88,135
General and administrative	14,189	22,083	49,750	60,416
Accretion of asset retirement obligations	275	278	829	820
(Gain) loss on sale of assets, net	—	—	—	(2)
TOTAL OPERATING EXPENSE	62,136	73,538	194,300	215,857
INCOME (LOSS) FROM OPERATIONS	75,233	66,180	190,493	147,664
OTHER INCOME (EXPENSE)				
Interest and investment income	44	53	137	123
Interest expense	(5,395)	(5,518)	(16,572)	(15,319)
Other income (expense)	365	60	293	(1,046)
TOTAL OTHER EXPENSE	(4,986)	(5,405)	(16,142)	(16,242)
NET INCOME (LOSS)	70,247	60,775	174,351	131,422
Net (income) loss attributable to noncontrolling interests	—	(22)	—	(1)
Distributions on Series A redeemable preferred units	—	—	—	(25)
Distributions on Series B cumulative convertible preferred units	(5,250)	(5,250)	(15,750)	(15,750)
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON AND SUBORDINATED UNITS	$ 64,997	$ 55,503	$ 158,601	$ 115,646
ALLOCATION OF NET INCOME (LOSS):				
General partner interest	$ —	$ —	$ —	$ —
Common units	64,997	29,188	134,608	71,037
Subordinated units	—	26,315	23,993	44,609
	$ 64,997	$ 55,503	$ 158,601	$ 115,646
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON AND SUBORDINATED UNIT:				
Per common unit (basic)	$ 0.32	$ 0.27	$ 0.87	$ 0.67
Weighted average common units outstanding (basic)	205,957	106,706	155,513	105,254
Per subordinated unit (basic)	$ —	$ 0.27	$ 0.48	$ 0.46
Weighted average subordinated units outstanding (basic)	—	96,329	50,458	96,021
Per common unit (diluted)	$ 0.32	$ 0.27	$ 0.87	$ 0.67
Weighted average common units outstanding (diluted)	205,957	106,706	155,513	105,254
Per subordinated unit (diluted)	$ —	$ 0.27	$ 0.48	$ 0.46
Weighted average subordinated units outstanding (diluted)	—	96,329	50,458	96,021

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

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

	Common units	Subordinated units	Partners' equity — common units	Partners' equity — subordinated units	Total equity
BALANCE AT DECEMBER 31, 2018	108,363	96,329	$ 714,823	$ 189,440	$ 904,263
Repurchases of common and subordinated units	(588)	—	(10,110)	—	(10,110)
Issuance of common units, net of offering costs	—	—	(43)	—	(43)
Issuance of common units for property acquisitions	57	—	943	—	943
Restricted units granted, net of forfeitures	1,545	—	—	—	—
Equity–based compensation	—	—	13,669	—	13,669
Distributions	—	—	(40,275)	(35,642)	(75,917)
Charges to partners' equity for accrued distribution equivalent rights	—	—	(1,044)	—	(1,044)
Distributions on Series B cumulative convertible preferred units	—	—	(5,250)	—	(5,250)
Net income (loss)	—	—	7,155	1,862	9,017
BALANCE AT MARCH 31, 2019	109,377	96,329	$ 679,868	$ 155,660	$ 835,528
Conversion of subordinated units	96,329	(96,329)	142,149	(142,149)	—
Repurchases of common and subordinated units	(377)	—	(6,164)	—	(6,164)
Restricted units granted, net of forfeitures	627	—	—	—	—
Equity–based compensation	—	—	3,332	—	3,332
Distributions	—	—	(40,471)	(35,642)	(76,113)
Charges to partners' equity for accrued distribution equivalent rights	—	—	(766)	—	(766)
Distributions on Series B cumulative convertible preferred units	—	—	(5,250)	—	(5,250)
Net income (loss)	—	—	72,956	22,131	95,087
BALANCE AT JUNE 30, 2019	205,956	—	$ 845,654	$ —	$ 845,654
Restricted units granted, net of forfeitures	(4)	—	—	—	—
Equity–based compensation	—	—	3,385	—	3,385
Distributions	—	—	(76,204)	—	(76,204)
Charges to partners' equity for accrued distribution equivalent rights	—	—	(511)	—	(511)
Distributions on Series B cumulative convertible preferred units	—	—	(5,250)	—	(5,250)
Net income (loss)	—	—	70,247	—	70,247
BALANCE AT SEPTEMBER 30, 2019	205,952	—	$ 837,321	$ —	$ 837,321

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

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

	Common units	Subordinated units	Partners' equity — common units	Partners' equity — subordinated units	Non-Controlling Interests	Total equity
BALANCE AT DECEMBER 31, 2017	103,456	95,388	$ 603,116	$ 164,138	$ 867	$ 768,121
Conversion of Series A redeemable preferred units	736	964	10,498	13,750	—	24,248
Repurchases of common and subordinated units	(451)	(23)	(8,099)	(342)	—	(8,441)
Issuance of common units, net of offering costs	8	—	138	—	—	138
Restricted units granted, net of forfeitures	1,177	—	—	—	—	—
Equity–based compensation[1]	—	—	18,075	219	—	18,294
Distributions	—	—	(32,581)	(19,912)	(52)	(52,545)
Charges to partners' equity for accrued distribution equivalent rights	—	—	(661)	—	—	(661)
Distributions on Series A redeemable preferred units	—	—	(13)	(12)	—	(25)
Distributions on Series B cumulative convertible preferred units	—	—	(5,250)	—	—	(5,250)
Net income (loss)	—	—	29,592	12,338	27	41,957
BALANCE AT MARCH 31, 2018	104,926	96,329	$ 614,815	$ 170,179	$ 842	$ 785,836
Repurchases of common and subordinated units	(35)	—	(630)	—	—	(630)
Issuance of common units, net of offering costs	509	—	8,929	—	—	8,929
Restricted units granted, net of forfeitures	94	—	—	—	—	—
Equity–based compensation[1]	—	—	8,521	—	—	8,521
Distributions	—	—	(33,011)	(20,109)	(62)	(53,182)
Charges to partners' equity for accrued distribution equivalent rights	—	—	(643)	—	—	(643)
Distributions on Series B cumulative convertible preferred units	—	—	(5,250)	—	—	(5,250)
Net income (loss)	—	—	22,798	5,941	(49)	28,690
BALANCE AT JUNE 30, 2018	105,494	96,329	$ 615,529	$ 156,011	$ 731	$ 772,271
Issuance of common units, net of offering costs	1,604	—	29,302	—	—	29,302
Issuance of common units for property acquisitions	1,227	—	22,530	—	—	22,530
Restricted units granted, net of forfeitures	5	—	—	—	—	—
Equity–based compensation[1]	—	—	8,991	—	—	8,991
Distributions	—	—	(36,052)	(32,511)	(47)	(68,610)
Charges to partners' equity for accrued distribution equivalent rights	—	—	(1,061)	—	—	(1,061)
Distributions on Series B cumulative convertible preferred units	—	—	(5,250)	—	—	(5,250)
Net income (loss)	—	—	34,410	26,342	23	60,775
BALANCE AT SEPTEMBER 30, 2018	108,330	96,329	$ 668,399	$ 149,842	$ 707	$ 818,948

[1] The change in Partners' equity for equity-based compensation during the nine-month period ended September 30, 2018 was incorrectly allocated between Partners' equity - common units and Partners' equity - subordinated units in the Partnership's prior reports. The Partnership concluded that this error was not material to any of the prior reporting periods. As such, the revision for this correction has been made to the prior periods presented.

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

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

	Nine Months Ended September 30,	
	2019	**2018**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income (loss)	$ 174,351	$ 131,422
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, and amortization	84,933	88,135
Accretion of asset retirement obligations	829	820
Amortization of deferred charges	779	653
(Gain) loss on commodity derivative instruments	(12,294)	68,194
Net cash (paid) received on settlement of commodity derivative instruments	18,320	(20,461)
Equity-based compensation	16,906	24,947
Exploratory dry hole expense	3	6,784
Deferred rent	—	802
(Gain) loss on sale of assets, net	—	(2)
Changes in operating assets and liabilities:		
Accounts receivable	28,454	(29,989)
Prepaid expenses and other current assets	(471)	7
Accounts payable, accrued liabilities, and other	(5,172)	18,515
Settlement of asset retirement obligations	(328)	(108)
NET CASH PROVIDED BY OPERATING ACTIVITIES	306,310	289,719
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisitions of oil and natural gas properties	(42,969)	(106,390)
Additions to oil and natural gas properties	(63,606)	(119,676)
Additions to oil and natural gas properties leasehold costs	(933)	(4,639)
Purchases of other property and equipment	(2,452)	(15)
Proceeds from the sale of oil and natural gas properties	550	8,390
Proceeds from farmouts of oil and natural gas properties	60,577	78,605
NET CASH USED IN INVESTING ACTIVITIES	(48,833)	(143,725)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from issuance of common units, net of offering costs	(43)	38,369
Distributions to common and subordinated unitholders	(228,234)	(174,348)
Distributions to Series A redeemable preferred unitholders	—	(690)
Distributions to Series B cumulative convertible preferred unitholders	(15,750)	(12,425)
Distributions to noncontrolling interests	—	(161)
Distribution equivalents paid	(2,982)	—
Redemptions of Series A redeemable preferred units	—	(2,115)
Repurchases of common and subordinated units	(16,916)	(9,071)
Borrowings under credit facility	252,500	264,500
Repayments under credit facility	(249,500)	(250,500)
Debt issuance costs and other	—	(754)
NET CASH USED IN FINANCING ACTIVITIES	(260,925)	(147,195)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(3,448)	(1,201)
CASH AND CASH EQUIVALENTS – beginning of the period	5,414	5,642
CASH AND CASH EQUIVALENTS – end of the period	$ 1,966	$ 4,441
SUPPLEMENTAL DISCLOSURE		
Interest paid	$ 15,854	$ 14,607

The accompanying notes are an integral part of these unaudited 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 that owns oil and natural gas mineral interests, which make up the vast majority of the asset base. The Partnership's assets also include nonparticipating royalty interests and overriding royalty interests. These interests, which are substantially non-cost-bearing, are collectively referred to as “mineral and royalty interests.” The Partnership’s mineral and royalty interests are located in 41 states in 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. The Partnership's common units trade on the New York Stock Exchange under the symbol "BSM."

Basis of Presentation

The accompanying unaudited interim consolidated financial statements of the Partnership have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States 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 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 Annual Report on Form 10-K for the year ended December 31, 2018 ("2018 Annual Report on Form 10-K").

The unaudited interim consolidated financial statements include the consolidated results of the Partnership. The results of operations for the nine months ended September 30, 2019 are not necessarily indicative of the results to be expected for the full year.

In the opinion of management, all 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. All intercompany balances and transactions have been eliminated.

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 using fair value or cost minus impairment if fair value is not readily determinable. 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 (loss) and equity in the accompanying unaudited interim consolidated financial statements.

The unaudited interim 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 unaudited interim 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 2018 Annual Report on Form 10-K. There have been no changes in such policies or the application of such policies during the nine months ended September 30, 2019, with the exception of ASC 842, as defined below.

Accounts Receivable

The following table presents information about the Partnership's accounts receivable:

	September 30, 2019	December 31, 2018
	(in thousands)	
Accounts receivable:		
Revenues from contracts with customers	$ 77,837	$ 107,804
Other	7,005	5,344
Total accounts receivable	$ 84,842	$ 113,148

Recent Accounting Pronouncements

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-02, *Leases (Topic 842)* ("ASC 842"), that supersedes Accounting Standards Codification ("ASC") 840, *Leases* by requiring lessees to recognize lease assets and lease liabilities classified as operating leases on the balance sheet. See Note 3 - Impact of ASC 842 Adoption for further details related to the Partnership's adoption of this standard.

In August 2018, the FASB issued ASU 2018-13, *Fair Value Measurement (Topic 820)*, which will remove, modify, and add certain required disclosures on fair value measurements. As amended, Topic 820 will no longer require the disclosure of the amount of and reasons for transfers between Level 1 and Level 2 of the fair value hierarchy, the policy of timing of transfers between levels, and the valuation processes for Level 3 fair value measurements. In addition, certain modifications to current disclosure requirements will be made, including clarifying that the measurement uncertainty disclosure is to communicate information about the uncertainty in measurement as of the reporting date. Certain disclosure requirements will also be added, including the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements. For certain unobservable inputs, an entity may disclose other quantitative information in place of the weighted average if the entity determines that other quantitative information would be a more reasonable and rational method to reflect the distribution of unobservable inputs used to develop Level 3 fair value measurements. The new standard will be effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, and early adoption is permitted. 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 — IMPACT OF ASC 842 ADOPTION

Leases

On January 1, 2019, the Partnership adopted ASC 842 using the modified retrospective method. ASC 842 requires the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under the previous guidance. The Partnership used January 1, 2019, the beginning of the period of adoption, as its date of initial application. The Partnership elected the package of practical expedients upon transition which will retain the lease classification for leases and any unamortized initial direct costs that existed prior to the adoption of the standard.

The adoption of the standard resulted in the recognition of operating lease right-of-use ("ROU") assets and operating lease liabilities on the consolidated balance sheet as of January 1, 2019. ROU assets and operating lease liabilities were less than 1% of the Partnership's total assets as of September 30, 2019 and were not considered material to the Partnership. There was no related impact on the consolidated statement of operations. The standard had no impact on the Partnership's debt covenant compliance under existing agreements.

The Partnership determines if an arrangement is a lease at inception by considering whether (1) explicitly or implicitly identified assets have been deployed in the agreement and (2) the Partnership obtains substantially all of the economic benefits from the use of that underlying asset and directs how and for what purpose the asset is used during the term of the agreement. Operating leases are included in Deferred charges and other long-term assets, Other current liabilities, and Other long-term liabilities in the consolidated balance sheets. As of September 30, 2019, none of the Partnership's leases were classified as financing leases.

ROU assets represent the Partnership's right to use an underlying asset for the lease term and operating lease liabilities represent the Partnership's obligation to make lease payments arising from the lease. ROU assets are recognized at commencement date and consist of the present value of remaining lease payments over the lease term, initial direct costs, prepaid lease payments less any lease incentives. Operating lease liabilities are recognized at commencement date based on the present value of remaining lease payments over the lease term. The Partnership uses the implicit rate, when readily determinable, or its incremental borrowing rate based on the information available at commencement date to determine the present value of lease payments.

The lease terms may include periods covered by options to extend the lease when it is reasonably certain that the Partnership will exercise that option and periods covered by options to terminate the lease when it is not reasonably certain that the Partnership will exercise that option. Lease expense for lease payments is recognized on a straight-line basis over the lease term. The Partnership made an accounting policy election to not recognize leases with terms of less than twelve months on the consolidated balance sheets and recognize those lease payments in the consolidated statements of operations on a straight-line basis over the lease term. In the event that the Partnership's assumptions and expectations change, it may have to revise its ROU assets and operating lease liabilities.

NOTE 4 — OIL AND NATURAL GAS PROPERTIES

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

2019 Acquisitions

During the nine months ended September 30, 2019, the Partnership closed on multiple acquisitions of mineral and royalty interests for total consideration of $43.9 million.

Acquisitions that were considered business combinations were primarily located in the Permian Basin. These acquisitions were funded with borrowings under the Credit Facility (as defined in Note 7 - Credit Facility) and funds from operating activities. Acquisition related costs of less than $0.1 million were expensed and included in the General and administrative line item of the consolidated statement of operations for the nine months ended September 30, 2019. The following table summarizes these acquisitions which were considered business combinations:

	Assets Acquired				Consideration Paid
	Proved	Unproved	Net Working Capital	Total Fair Value	Cash
			(in thousands)		
February	$ 173	$ 8,437	$ 1	$ 8,611	$ 8,611
March	24	—	—	24	24
June	527	3,268	—	3,795	3,795
Total fair value	$ 724	$ 11,705	$ 1	$ 12,430	$ 12,430

In addition, during the nine months ended September 30, 2019, the Partnership acquired mineral and royalty interests that consisted of substantially all unproved oil and natural gas properties from various sellers for an aggregate of $31.5 million. These acquisitions were considered asset acquisitions and were primarily located in East Texas and the Permian Basin. The cash portion of the consideration paid for these acquisitions of $30.6 million was funded with borrowings under the Credit Facility and funds from operating activities, and $0.9 million was funded through the issuance of common units of the Partnership based on the fair values of the common units issued on the acquisition dates.

2018 Acquisitions

During the year ended December 31, 2018, the Partnership closed on multiple acquisitions of mineral and royalty interests for total consideration of $149.9 million.

Acquisitions that were considered business combinations were primarily located in the Permian Basin. The cash portion of the consideration paid for these acquisitions was funded with borrowings under the Credit Facility and funds from operating activities. Acquisition related costs of $0.2 million were expensed and included in the General and administrative line item of the consolidated statement of operations for the year ended December 31, 2018. The following table summarizes these acquisitions which were considered business combinations:

	Assets Acquired				Consideration Paid	
	Proved	Unproved	Net Working Capital	Total Fair Value	Cash	Fair Value of Common Units Issued
	(in thousands)					
March	$ 984	$ 21,452	$ 133	$ 22,569	$ 22,569	$ —
June	883	13,688	8	14,579	14,579	—
July	4,349	7,944	215	12,508	3,764	8,744
August	5,000	34,673	74	39,747	26,461	13,286
September	1,176	—	—	1,176	1,176	—
November	1,166	—	—	1,166	1,166	—
Total fair value	$ 13,558	$ 77,757	$ 430	$ 91,745	$ 69,715	$ 22,030

In addition, during 2018, the Partnership acquired mineral and royalty interests that consisted of substantially all unproved oil and natural gas properties from various sellers for an aggregate of $58.2 million. These acquisitions were considered asset acquisitions and were primarily located in East Texas and the Permian Basin. The cash portion of the consideration paid for these acquisitions of $57.6 million was funded with borrowings under the Credit Facility and funds from operating activities, and $0.6 million was funded through the issuance of common units of the Partnership based on the fair values of the common units issued on the acquisition dates.

During 2018, the Partnership acquired the remaining noncontrolling interest in certain subsidiaries for $1.7 million in cash and merged the subsidiaries into its existing structure.

Farmout Agreements

In 2017, the Partnership entered into two farmout arrangements designed to reduce its working interest capital expenditures and thereby significantly lower its capital spending other than for royalty and mineral acquisitions. Under these agreements, the Partnership conveyed its rights to participate in certain non-operated working interest opportunities to external capital providers while retaining value from these interests in the form of additional royalty income or retained economic interests.

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., a subsidiary of Exxon Mobil Corporation. The Partnership has an approximate 50% working interest in the acreage and is the largest mineral owner. A total of 20 wells were drilled over an initial phase, beginning with wells spud after January 1, 2017. Canaan elected to participate in an additional phase that began in September 2018 and continues for the lesser of 2 years or until 20 wells have been drilled. After the completion of the second phase, Canaan will have the option to elect to participate in a similar third phase. During the first three phases of the agreement, Canaan commits on a phase-by-phase basis and funds 80% of the Partnership's drilling and completion costs and is assigned 80% of the Partnership's working interests in such wells (40% working interest on an 8/8ths basis) as the wells are drilled. 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 receives an overriding royalty interest (“ORRI”) before payout and an increased ORRI after payout on all wells drilled under the agreement. From the inception of the agreement through September 30, 2019, the Partnership has received $89.7 million from Canaan under the agreement. When working interests in farmout wells are assigned to Canaan, the Partnership's Oil and natural gas properties and Other long-term liabilities are reduced by the reimbursed capital costs. As of September 30, 2019, the Partnership had assigned to Canaan working interests in certain wells drilled and completed, and as such, $0.9 million of the farmout reimbursements received from Canaan are included in the Other long-term liabilities line item of the consolidated balance sheet.

Pivotal Farmout

On November 21, 2017, the Partnership entered into a farmout agreement with Pivotal Petroleum Partners (“Pivotal”), a portfolio company of Tailwater Capital, LLC. The farmout agreement covers substantially all of the Partnership's remaining working interests under active development in the Shelby Trough area of East Texas, targeting the Haynesville and Bossier shale acreage (after giving effect to the Canaan Farmout), until November 2025. Pivotal will earn the Partnership's remaining working interest in wells operated by XTO Energy Inc. in San Augustine County, Texas not covered by the Canaan Farmout (10% working interest on an 8/8th basis), as well as 100% of the Partnership's working interests (ranging from approximately 12.5% to 25% on an 8/8ths basis) in wells operated by its other major operator in San Augustine and Angelina counties, Texas. Initially, Pivotal is obligated to fund the development of up to 80 wells across several development areas and then has options to continue funding the Partnership's working interest across those areas for the duration of the farmout agreement. Pivotal will fund designated groups of wells. Once Pivotal achieves a specified payout for a designated well group, the Partnership will obtain a majority of the original working interest in such well group. From the inception of the agreement through September 30, 2019, the Partnership received $114.5 million from Pivotal under the agreement. When working interests in farmout wells are assigned to Pivotal, the Partnership's Oil and natural gas properties and Other long-term liabilities are reduced by the reimbursed capital costs. As of September 30, 2019, the Partnership had assigned to Pivotal working interests in certain wells drilled and completed, and as such, $0.4 million of the farmout reimbursements received from Pivotal are included in the Other long-term liabilities line item of the consolidated balance sheet.

As of December 31, 2018, $11.6 million and $41.2 million were included in the Other long-term liabilities line item of the consolidated balance sheet related to the farmout agreements with Canaan and Pivotal, respectively.

NOTE 5 — COMMODITY DERIVATIVE 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 commodity derivative financial instruments. From time to time, such instruments may include variable-to-fixed-price swaps, costless collars, fixed-price contracts 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, 2019, the Partnership’s open derivative contracts consisted of fixed-price swap contracts and costless collar contracts. A fixed-price swap contract between the Partnership and the counterparty specifies a fixed commodity price and a future settlement date. A costless collar contract between the Partnership and the counterparty specifies a floor and a ceiling commodity price and a future settlement date. The Partnership has not designated any of its contracts as fair value or cash flow hedges. Accordingly, the 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, 2019 and December 31, 2018. See Note 6 – Fair Value Measurements for further discussion.

The Partnership's derivative contracts expose it to credit risk in the event of nonperformance by counterparties that may adversely impact the fair value of the Partnership's commodity derivative assets. 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, 2019, the Partnership had nine counterparties, all of which are rated Baa1 or better by Moody's and are lenders under the Credit Facility.

The tables below summarize the fair values and classifications of the Partnership's derivative instruments, as well as the gross recognized derivative assets, liabilities, and amounts offset in the consolidated balance sheets as of each date:

		September 30, 2019		
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	$ 33,710	$ (656)	$ 33,054
Long-term asset	Deferred charges and other long-term assets	9,269	(311)	8,958
Total assets		$ 42,979	$ (967)	$ 42,012
Liabilities:				
Current liability	Commodity derivative liabilities	$ 656	$ (656)	$ —
Long-term liability	Commodity derivative liabilities	311	(311)	—
Total liabilities		$ 967	$ (967)	$ —

		December 31, 2018		
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	$ 38,746	$ (776)	$ 37,970
Long-term asset	Deferred charges and other long-term assets	11,518	(1,450)	10,068
Total assets		$ 50,264	$ (2,226)	$ 48,038
Liabilities:				
Current liability	Commodity derivative liabilities	$ 776	$ (776)	$ —
Long-term liability	Commodity derivative liabilities	1,450	(1,450)	—
Total liabilities		$ 2,226	$ (2,226)	$ —

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 and consolidated statements of cash flows and consist of the following for the periods presented:

Derivatives not designated as hedging instruments	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
	(in thousands)			
Beginning fair value of commodity derivative instruments	$ 31,368	$ (44,043)	$ 48,038	$ (5,028)
Gain (loss) on oil derivative instruments	18,132	(18,830)	(13,224)	(63,325)
Gain (loss) on natural gas derivative instruments	6,158	316	25,518	(4,869)
Net cash paid (received) on settlements of oil derivative instruments	(2,938)	11,280	(5,748)	25,809
Net cash paid (received) on settlements of natural gas derivative instruments	(10,708)	(1,484)	(12,572)	(5,348)
Net change in fair value of commodity derivative instruments	10,644	(8,718)	(6,026)	(47,733)
Ending fair value of commodity derivative instruments	$ 42,012	$ (52,761)	$ 42,012	$ (52,761)

The Partnership had the following open derivative contracts for oil as of September 30, 2019:

Period and Type of Contract	Volume (Bbl)	Weighted Average Price (Per Bbl)	Range (Per Bbl) Low	Range (Per Bbl) High
Oil Swap Contracts:				
2019				
Third Quarter	285,000	$ 58.37	$ 52.82	$ 63.75
Fourth Quarter	936,000	58.50	52.82	63.75
2020				
First Quarter	510,000	$ 57.14	$ 54.92	$ 58.65
Second Quarter	510,000	57.14	54.92	58.65
Third Quarter	510,000	57.14	54.92	58.65
Fourth Quarter	510,000	57.14	54.92	58.65

Period and Type of Contract	Volume (Bbl)	Weighted Average Floor Price (Per Bbl)	Weighted Average Ceiling Price (Per Bbl)
Oil Collar Contracts:			
2019			
Third Quarter	20,000	$ 65.00	$ 74.00
Fourth Quarter	60,000	65.00	74.00
2020			
First Quarter	210,000	$ 56.43	$ 67.14
Second Quarter	210,000	56.43	67.14
Third Quarter	210,000	56.43	67.14
Fourth Quarter	210,000	56.43	67.14

The Partnership had the following open derivative contracts for natural gas as of September 30, 2019:

Period and Type of Contract	Volume (MMBtu)	Weighted Average Price (Per MMBtu)	Range (Per MMBtu) Low	Range (Per MMBtu) High
Natural Gas Swap Contracts:				
2019				
Fourth Quarter	14,640,000	$ 2.96	$ 2.81	$ 3.20
2020				
First Quarter	10,010,000	$ 2.69	$ 2.55	$ 2.74
Second Quarter	10,010,000	2.69	2.55	2.74
Third Quarter	10,120,000	2.69	2.55	2.74
Fourth Quarter	10,120,000	2.69	2.55	2.74

NOTE 6 — FAIR VALUE MEASUREMENTS

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, *Fair Value Measurement*, 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, 2019 or the year ended December 31, 2018.

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, 2019 and December 31, 2018 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 – Commodity Derivative 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				
	Level 1	Level 2	Level 3	Effect of Counterparty Netting	Total
			(in thousands)		
As of September 30, 2019					
Financial Assets					
Commodity derivative instruments	$ —	$ 42,979	$ —	$ (967)	$ 42,012
Financial Liabilities					
Commodity derivative instruments	$ —	$ 967	$ —	$ (967)	$ —
As of December 31, 2018					
Financial Assets					
Commodity derivative instruments	$ —	$ 50,264	$ —	$ (2,226)	$ 48,038
Financial Liabilities					
Commodity derivative instruments	$ —	$ 2,226	$ —	$ (2,226)	$ —

Assets and Liabilities Measured at Fair Value on a Non-Recurring Basis

Nonfinancial assets and liabilities measured at fair value on a non-recurring 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, timing of future production, 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 – Oil and Natural Gas Properties.

Oil and natural gas properties are measured at fair value on a non-recurring 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 proved reserves, future commodity prices, timing of future production, operating costs, future capital expenditures, 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, 2019 or December 31, 2018.

There were no assets measured at fair value on a non-recurring basis, after initial recognition, for the nine months ended September 30, 2019 and 2018.

NOTE 7 — CREDIT FACILITY

The Partnership maintains a senior secured revolving credit agreement, as amended (the “Credit Facility”). The Credit Facility has an aggregate maximum credit amount of $1.0 billion and terminates on November 1, 2022. The commitment of the lenders equals the lesser of the aggregate maximum credit amount and the borrowing base. The amount of the borrowing base is redetermined semi-annually, usually in October and April, and 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. Effective May 4, 2018, the borrowing base redetermination increased the borrowing base from $550.0 million to $600.0 million. Effective October 31, 2018, the borrowing base was further increased to $675.0 million and remained at that level until the most recent redetermination, effective October 23, 2019, which reduced the borrowing base to $650.0 million.

Outstanding borrowings under the Credit Facility bear interest at a floating rate elected by the Partnership 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. Prior to October 31, 2018, the applicable margin ranged 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. Effective October 31, 2018, the applicable margin for the alternative base rate was reduced to between 0.75% and 1.75% and the applicable margin for LIBOR was reduced to between 1.75% and 2.75%.

The weighted-average interest rate of the Credit Facility was 4.30% and 4.76% as of September 30, 2019 and December 31, 2018, 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% if the borrowing base utilization percentage is equal to or greater than 50%. The Credit Facility is secured by substantially all of the Partnership’s oil and natural gas production and assets.

The Credit Facility contains various limitations on future borrowings, leases, hedging, and sales of assets. Additionally, the Credit Facility 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, 2019, the Partnership was in compliance with all financial covenants in the Credit Facility.

The aggregate principal balance outstanding was $413.0 million and $410.0 million at September 30, 2019 and December 31, 2018, respectively. The unused portion of the available borrowings under the Credit Facility were $262.0 million and $265.0 million at September 30, 2019 and December 31, 2018, 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 recorded.

Put Option Related to Noble Acquisition

By acquiring 100% of the issued and outstanding securities of Samedan Royalty, LLC, now NAMP Holdings, LLC, on November 28, 2017 from Noble Energy US Holdings, LLC, the Partnership acquired a 100% interest in Comin-Temin, LLC, now NAMP GP, LLC ("Holdings"), Comin 1989 Partnership LLLP, now NAMP 1, LP ("Comin"), and Temin 1987 Partnership LLLP, now NAMP 2, LP ("Temin"). Pursuant to certain co-ownership agreements, various co-owners hold undivided beneficial ownership interests in 45.33% and 42.63% of the minerals interests held of record by Holdings and Temin, respectively as of September 30, 2019. Based on the terms of the co-ownership agreements, the co-owners each have an unconditional option to require Comin or Temin, as applicable, to purchase their beneficial ownership interest in the mineral interests held of record by Holdings or Temin, as applicable, at any time within 30 days of receiving such repurchase notice. The purchase price of the beneficial ownership interest shall be based on an evaluation performed by Comin or Temin, as applicable, in good faith. As of September 30, 2019, the Partnership had not received notice from any co-owners to exercise their repurchase option, and as such, no liability was recorded.

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, 2019 will be resolved without material adverse effect on the Partnership's financial condition or operations.

NOTE 9 — INCENTIVE COMPENSATION

The table below summarizes incentive compensation expense recorded in the General and administrative line item of the consolidated statements of operations for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands)			
Cash—short and long-term incentive plans	$ 1,092	$ 4,366	$ 4,336	$ 7,568
Equity-based compensation—restricted common and subordinated units	2,552	3,404	8,162	10,180
Equity-based compensation—restricted performance units	727	5,611	6,984	13,026
Board of Directors incentive plan	587	581	1,760	1,741
Total incentive compensation expense	$ 4,958	$ 13,962	$ 21,242	$ 32,515

NOTE 10 — PREFERRED UNITS

Series A Redeemable Preferred Units

As of September 30, 2019 and December 31, 2018, there were no Series A redeemable preferred units outstanding. The Series A redeemable preferred units were entitled to an annual distribution of 10% of the outstanding funded capital of the Series A redeemable preferred units, payable on a quarterly basis in arrears.

The Series A redeemable preferred units were convertible into common and subordinated units at any time at the option of the Series A redeemable preferred unitholders. The Series A redeemable preferred units had 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.

The Series A redeemable preferred unitholders had the option to elect to have the Partnership redeem, at face value, all remaining Series A redeemable preferred units, effective as of December 31, 2017, plus any accrued and unpaid distributions. All Series A redeemable preferred units not redeemed by March 31, 2018 automatically converted to common and subordinated units effective as of January 1, 2018 or as soon as practicable thereafter.

For the nine months ended September 30, 2018, 2,115 Series A redeemable preferred units were redeemed for $2.1 million, including accrued unpaid yield, and 24,248 Series A redeemable preferred units totaling $24.2 million were converted into 735,758 common units and 963,681 subordinated units as a result of the mandatory conversion subsequent to December 31, 2017.

Series B Cumulative Convertible Preferred Units

On November 28, 2017, the Partnership issued and sold in a private placement 14,711,219 Series B cumulative convertible preferred units representing limited partner interests in the Partnership for a cash purchase price of $20.3926 per Series B cumulative convertible preferred unit, resulting in total proceeds of approximately $300.0 million.

The Series B cumulative convertible preferred units are entitled to an annual distribution of 7%, payable on a quarterly basis in arrears. For the eight quarters consisting of the quarter in respect of which the initial distribution is paid and the seven full quarters thereafter, the quarterly distribution may be paid, at the sole option of the Partnership, (i) in-kind in the form of additional Series B cumulative convertible preferred units (the "Series B PIK Units"), (ii) in cash, or (iii) in a combination of Series B PIK Units and cash. Beginning with the ninth quarter, all Series B cumulative convertible preferred unit distributions shall be paid in cash. The number of Series B PIK Units to be issued, if any, shall equal the quotient of the Series B cumulative convertible preferred unit distribution amount (or portion thereof) divided by the Series B cumulative convertible preferred unit purchase price of $20.3926.

The Series B cumulative convertible preferred units are convertible into common units of the Partnership on November 29, 2019 and once per quarter thereafter. At such time, the Series B cumulative convertible preferred units may be converted by each holder at its option, in whole or in part, into common units on a one-for-one basis at the purchase price of $20.3926, adjusted to give effect to any accrued but unpaid accumulated distributions on the applicable Series B cumulative convertible preferred units through the most recent declaration date. However, the Partnership shall not be obligated to honor any request for such conversion if such request does not involve an underlying value of common units of at least $10.0 million based on the closing trading price of common units on the trading day immediately preceding the conversion notice date, or such lesser amount to the extent such exercise covers all of a holder's Series B cumulative convertible preferred units.

The Series B cumulative convertible preferred units had a carrying value of $298.4 million, including accrued distributions of $5.3 million, as of September 30, 2019 and December 31, 2018. The Series B cumulative convertible preferred units are classified as mezzanine equity on the consolidated balance sheets since certain provisions of redemption are outside the control of the Partnership.

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 units have all the rights of a unitholder, including non-forfeitable distribution rights. As participating securities, the restricted common 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 Partnership assesses the Series B cumulative convertible preferred units on an as-converted basis for the purpose of calculating diluted EPU. For the three and nine months ended September 30, 2019 and 2018, there were no common units related to the Partnership's Series B cumulative convertible preferred units included in the calculation of diluted EPU.

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. For the three and nine months ended September 30, 2019 and 2018, 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands, except per unit amounts)			
NET INCOME (LOSS)	$ 70,247	$ 60,775	$ 174,351	$ 131,422
Net (income) loss attributable to noncontrolling interests	—	(22)	—	(1)
Distributions on Series A redeemable preferred units	—	—	—	(25)
Distributions on Series B cumulative convertible preferred units	(5,250)	(5,250)	(15,750)	(15,750)
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON AND SUBORDINATED UNITS	64,997	55,503	158,601	115,646
ALLOCATION OF NET INCOME (LOSS):				
General partner interest	$ —	$ —	$ —	$ —
Common units	64,997	29,188	134,608	71,037
Subordinated units	—	26,315	23,993	44,609
	$ 64,997	$ 55,503	$ 158,601	$ 115,646
Weighted average common units outstanding:				
Weighted average common units outstanding (basic)	205,957	106,706	155,513	105,254
Effect of dilutive securities	—	—	—	—
Weighted average common units outstanding (diluted)	205,957	106,706	155,513	105,254
Weighted average subordinated units outstanding:				
Weighted average subordinated units outstanding (basic)	—	96,329	50,458	96,021
Effect of dilutive securities	—	—	—	—
Weighted average subordinated units outstanding (diluted)	—	96,329	50,458	96,021
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON AND SUBORDINATED UNIT:				
Per common unit (basic)	$ 0.32	$ 0.27	$ 0.87	$ 0.67
Per subordinated unit (basic)	—	0.27	0.48	0.46
Per common unit (diluted)	0.32	0.27	0.87	0.67
Per subordinated unit (diluted)	—	0.27	0.48	0.46

The following units of potentially dilutive securities were excluded from the computation of diluted weighted average units outstanding because their inclusion would be anti-dilutive:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands)			
Potentially dilutive securities (common units):				
Series A redeemable preferred units on an as-converted basis	—	—	—	189
Series B cumulative convertible preferred units on an as-converted basis	14,969	14,969	14,969	14,969
	14,969	14,969	14,969	15,158
Potentially dilutive securities (subordinated units):				
Series A redeemable preferred units on an as-converted basis	—	—	—	247

NOTE 12 — COMMON AND SUBORDINATED UNITS

Common and Subordinated Units

The common units and subordinated units represent limited partner interests in the Partnership. The partnership agreement restricts unitholders’ voting rights by providing that any units held by a person or group that owns 15% or more of any class of units then outstanding, other than the limited partners in Black Stone Minerals Company, L.P. prior to the initial public offering of BSM, their transferees, persons who acquired such units with the prior approval of the board of directors of the Partnership's general partner (the "Board"), holders of Series B cumulative convertible preferred units in connection with any vote, consent or approval of the Series B cumulative convertible preferred units as a separate class, and persons who own 15% or more of any class as a result of any redemption or purchase of any other person's units or similar action by the Partnership or any conversion of the Series B cumulative convertible preferred units at the Partnership's option or in connection with a change of control, may not vote on any matter.

Prior to the end of the subordination period (as defined in the partnership agreement), the holders of common units and subordinated units were entitled to participate in distributions and exercise the rights and privileges provided to limited partners holding common units and subordinated units under the partnership agreement.

The partnership agreement generally provides that any distributions during the subordination period are paid each quarter in the following manner:

- *first*, to the holders of the Series B cumulative convertible preferred units in an amount equal to 7% per annum, subject to certain adjustments;
- *second*, to the holders of common units, until each common unit has received the applicable minimum quarterly distribution plus any arrearages from prior quarters; and
- *third*, to the holders of subordinated units, until each subordinated unit has received the applicable minimum quarterly distribution.

If the distributions to common and subordinated unitholders exceeded the applicable minimum quarterly distribution per unit, then such excess amounts were distributed pro rata on the common and subordinated units as if they were a single class. In connection with the expiration of the subordination period, each outstanding subordinated unit converted into one common unit on May 24, 2019 and the priority right of the common unitholders ceased to exist.

The following table provides information about the Partnership's per unit distributions to common unitholders:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
DISTRIBUTIONS DECLARED AND PAID:				
Per common unit	$ 0.3700	$ 0.3375	$ 1.1100	$ 0.9625

The Partnership's per unit distributions declared and paid to subordinated unitholders for the three and nine months ended September 30, 2018 were $0.3375 and $0.7550, respectively. For the three months ended September 30, 2019 there were no subordinated distributions as all subordinated units converted into common units on May 24, 2019. The Partnership's per unit distributions declared and paid to subordinated unitholders for the six months ended June 30, 2019 were $0.7400.

End of the Subordination Period

The subordination period under the partnership agreement ended on the first business day after the Partnership earned and paid an aggregate amount of at least $1.35 (the annualized minimum quarterly distribution applicable for quarterly periods ending March 31, 2019 and thereafter) multiplied by the total number of outstanding common and subordinated units for a period of four consecutive, non-overlapping quarters ending on or after March 31, 2019, and there were no outstanding arrearages on the common units. This test was met upon the payment of the distribution for the first quarter of 2019. Accordingly, 96,328,836 subordinated units converted into 96,328,836 common units on May 24, 2019 and common units are no longer entitled to arrearages.

Common Unit Repurchase Program

On November 5, 2018, the Board authorized the repurchase of up to $75.0 million in common units. The repurchase program authorizes the Partnership to make repurchases on a discretionary basis as determined by management, subject to market conditions, applicable legal requirements, available liquidity, and other appropriate factors. The Partnership repurchased a total of 136,665 common units for an aggregate cost of $2.2 million under this program for the nine months ended September 30, 2019. As of September 30, 2019, the Partnership has repurchased $4.2 million in common units under the repurchase program since inception. The repurchase program is funded from the Partnership's cash on hand or availability on the Credit Facility. Any repurchased units are canceled.

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 amount of up to $100,000,000. Sales of common units, 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 SEC 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.

For the nine months ended September 30, 2019, the Partnership sold no common units under the ATM Program. For the nine months ended September 30, 2018, the Partnership sold 2,121,643 common units under the ATM program for net proceeds of $38.4 million. As of September 30, 2019, the Partnership has raised net proceeds of $73.0 million under the ATM Program since inception.

NOTE 13 — SUBSEQUENT EVENTS

On October 23, 2019, the Board approved a distribution for the three months ended September 30, 2019 of $0.37 per common unit. Distributions will be payable on November 21, 2019 to unitholders of record at the close of business on November 14, 2019.

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 consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2018 ("2018 Annual Report on Form 10-K"). 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.”

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;
- the overall supply and demand for oil and natural gas, 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 for hydraulic fracturing;
- the availability of pipeline capacity and 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;
- the level of drilling activity by our operators in the Shelby Trough; 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 2018 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 and managers of oil and natural gas mineral interests in the United States. Our principal business is maximizing the value of our existing mineral and royalty assets through active management and expanding our asset base through acquisitions of additional mineral and royalty interests. We maximize value through marketing our mineral assets for lease, creatively structuring the terms on those leases to encourage and accelerate drilling activity, and selectively participating alongside our lessees on a working interest basis. 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, 2019, our mineral and royalty interests were located in 41 states in the continental United States, including all of the major onshore producing basins. These non-cost-bearing interests include ownership in over 60,000 producing wells. We also own non-operated working interests, a significant portion of which are on our positions where we also have a mineral and royalty interest. We recognize oil and natural gas revenue from our mineral and royalty and non-operated working interests in producing wells when control of the oil and natural gas produced is transferred to the customer and collectability of the sales price is reasonably assured. 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

In the first nine months of 2019, we acquired mineral and royalty interests primarily in the Permian Basin and in East Texas for aggregate consideration of $43.0 million in cash and $0.9 million in our common units. Additional information regarding acquisitions is contained in Note 4 – Oil and Natural Gas Properties to our unaudited interim consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q.

Common Unit Repurchase Program

On November 5, 2018, the Board authorized the repurchase of up to $75.0 million in common units. The repurchase program authorizes us to make repurchases on a discretionary basis as determined by management, subject to market conditions, applicable legal requirements, available liquidity, and other appropriate factors. We have repurchased a total of 136,665 common units for an aggregate cost of $2.2 million under this program for the nine months ended September 30, 2019. The repurchase program is funded from our cash on hand or availability on the Credit Facility (as defined below). Any repurchased units are canceled.

Shelby Trough Update

As anticipated, drilling activity has slowed on our Shelby Trough acreage in East Texas, in part due to the current natural gas price environment. XTO Energy Inc. has informed us that it intends to postpone most of its remaining 2019 drilling and completion activity until 2020 or later. In addition, BPX Energy ("BPX") has significantly reduced current development in the

Shelby Trough and has released over 100,000 gross acres. Much of this area has been delineated with seismic data and through BPX's drilling to date with successful wells in both the Haynesville and Bossier shales. While a protracted slowdown of activity in the Shelby Trough would reduce production and, in turn, cash available for distribution, we intend to place that acreage with another operator or operators in late 2019 or early 2020.

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 and Demand

Oil and natural gas prices have been historically volatile based upon the dynamics of supply and demand. The U.S. Energy Information Administration ("EIA") forecasts that the WTI spot oil price will average $56.26 per Bbl in 2019 and $54.43 per Bbl in 2020 and that the Henry Hub spot natural gas prices will average $2.57 per MMBtu in 2019 and $2.52 per MMBtu in 2020.

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 of fixed-price swap contracts and costless collar contracts.

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

	2019			2018		
Benchmark Prices[1]	**Third Quarter**	**Second Quarter**	**First Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
WTI spot oil price ($/Bbl)	$ 54.09	$ 58.20	$ 60.19	$ 73.16	$ 74.13	$ 64.87
Henry Hub spot natural gas ($/MMBtu)	$ 2.37	$ 2.42	$ 2.73	$ 3.01	$ 2.96	$ 2.81

[1] Source: EIA

As we are not the operator of record on any producing 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:

	2019			2018		
U.S. Rotary Rig Count[1]	**Third Quarter**	**Second Quarter**	**First Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
Oil	713	793	816	863	858	797
Natural gas	146	173	190	189	187	194
Other	1	1	—	2	2	2
Total	860	967	1,006	1,054	1,047	993

[1] 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, natural gas storage injections in the United States have outpaced the previous five-year average so far during the 2019 injection season as a result of rising natural gas production. The EIA forecasts that natural gas inventories will reach 1.8 trillion cubic feet on March 31, 2020, which would be 11% above the previous five-year average and 35% above March 2019 levels.

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

	2019			2018		
Region[1]	**Third Quarter**	**Second Quarter**	**First Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
East	826	526	210	763	460	229
Midwest	973	568	241	836	455	266
Mountain	199	134	64	177	139	87
Pacific	291	255	113	262	257	166
South Central	1,029	907	502	829	841	606
Total	3,318	2,390	1,130	2,867	2,152	1,354

[1] 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 and Distributable cash flow.

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 constitute 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 New York Mercantile Exchange ("NYMEX") prices are referred to as differentials. All 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 West Texas Intermediate ("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 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 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 enter into 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 variable-to-fixed-price swaps, fixed-price contracts, costless collars, and other contractual arrangements. The impact of these derivative instruments could affect the amount of revenue we ultimately realize.

Our open derivative contracts consist of fixed-price swap contracts and costless collar 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. Our costless collar contracts contain a fixed floor price and a fixed ceiling price. If the market price exceeds the fixed ceiling price, we pay the difference between the fixed ceiling price and the market settlement price. If the market price is below the fixed floor price, we receive the difference between the market settlement price and the fixed floor price. If the market price is between the fixed floor and fixed ceiling price, no payments are due from either party. If we have multiple contracts outstanding with a single counterparty, unless restricted by our agreement, we will net settle the contract payments.

We may employ contractual arrangements other than fixed-price swap contracts and costless collar 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, 2019 are detailed in Note 5 – Commodity Derivative Financial Instruments to our unaudited consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q.

Pursuant to the terms of our Credit Facility, we are allowed to hedge certain percentages of expected future monthly production volumes equal to the lesser of (i) internally forecasted production and (ii) the average of reported production for the most recent three months.

We are allowed to hedge up to 90% of such volumes for the first 24 months, 70% for months 25 through 36, and 50% for months 37 through 48. As of September 30, 2019, we have hedged 94% and 71% of our available oil and condensate hedge volumes for 2019 and 2020, respectively. Also, we have hedged 87% and 62% of our available natural gas hedge volumes for 2019 and 2020, respectively.

We intend 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 related to such production for the following 12 to 30 months. We do not enter into derivative instruments for speculative purposes.

Non-GAAP Financial Measures

Adjusted EBITDA and Distributable cash flow 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 during the subordination period, cash interest expense, and distributions to noncontrolling interests and preferred unitholders.

Adjusted EBITDA and Distributable cash flow 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 GAAP in the United States as measures of our financial performance.

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

The following table presents a reconciliation of net income (loss), the most directly comparable GAAP financial measure, to Adjusted EBITDA and Distributable cash flow for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(in thousands)			
Net income (loss)	$ 70,247	$ 60,775	$ 174,351	$ 131,422
Adjustments to reconcile to Adjusted EBITDA:				
Depreciation, depletion, and amortization	27,375	29,273	84,933	88,135
Interest expense	5,395	5,518	16,572	15,319
Income tax expense (benefit)	(353)	(2)	(187)	1,059
Accretion of asset retirement obligations	275	278	829	820
Equity–based compensation	3,867	9,596	16,906	24,947
Unrealized (gain) loss on commodity derivative instruments	(10,644)	8,718	6,026	47,733
Adjusted EBITDA	96,162	114,156	299,430	309,435
Adjustments to reconcile to Distributable cash flow:				
Change in deferred revenue	37	(1)	27	1,300
Cash interest expense	(5,132)	(5,287)	(15,793)	(14,571)
(Gain) loss on sale of assets, net	—	—	—	(2)
Estimated replacement capital expenditures[1]	—	(2,750)	(2,750)	(8,750)
Cash paid to noncontrolling interests	—	(47)	—	(161)
Preferred unit distributions	(5,250)	(5,250)	(15,750)	(15,775)
Distributable cash flow	$ 85,817	$ 100,821	$ 265,164	$ 271,476

[1] The Board established a replacement capital expenditure estimate of $13.0 million for the period of April 1, 2017 to March 31, 2018 and $11.0 million for the period of April 1, 2018 to March 31, 2019. Due to the expiration of the subordination period, no replacement capital expenditure estimate will be established for periods subsequent to March 31, 2019.

Results of Operations

Three Months Ended September 30, 2019 Compared to Three Months Ended September 30, 2018

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

	Three Months Ended September 30,			
	2019	2018	Variance	
	(Dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)	1,207	1,251	(44)	(3.5)%
Natural gas (MMcf)[1]	19,816	19,153	663	3.5 %
Equivalents (MBoe)	4,510	4,443	67	1.5 %
Equivalents/day (MBoe)	49.0	48.3	0.7	1.4 %
Realized prices, without derivatives:				
Oil and condensate ($/Bbl)	$ 56.55	$ 66.12	$ (9.57)	(14.5)%
Natural gas ($/Mcf)[1]	2.09	3.29	(1.20)	(36.5)%
Equivalents ($/Boe)	$ 24.30	$ 32.81	$ (8.51)	(25.9)%
Revenue:				
Oil and condensate sales	$ 68,255	$ 82,712	$ (14,457)	(17.5)%
Natural gas and natural gas liquids sales[1]	41,340	63,080	(21,740)	(34.5)%
Lease bonus and other income	3,484	12,440	(8,956)	(72.0)%
Revenue from contracts with customers	113,079	158,232	(45,153)	(28.5)%
Gain (loss) on commodity derivative instruments	24,290	(18,514)	42,804	231.2 %
Total revenue	$ 137,369	$ 139,718	$ (2,349)	(1.7)%
Operating expenses:				
Lease operating expense	$ 4,356	$ 4,229	$ 127	3.0 %
Production costs and ad valorem taxes	15,877	17,641	(1,764)	(10.0)%
Exploration expense	64	34	30	88.2 %
Depreciation, depletion, and amortization	27,375	29,273	(1,898)	(6.5)%
General and administrative	14,189	22,083	(7,894)	(35.7)%

[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, 2019 decreased compared to the quarter ended September 30, 2018. The decrease in total revenue was due to decreases in oil and condensate sales, natural gas and NGL sales, and lease bonus and other income. The overall decrease in total revenue was partially offset by a gain on our commodity derivative instruments in the third quarter of 2019, compared to a loss in the third quarter of 2018.

Oil and condensate sales. Oil and condensate sales during the current quarter were lower than the third quarter of 2018 due to lower realized commodity prices and lower production volumes. Our mineral and royalty interest oil and condensate volumes decreased 2% in the third quarter of 2019 relative to the corresponding period in 2018, primarily driven by production decreases in the Bakken/Three Forks and Eagle Ford play trends. Our mineral and royalty interest oil and condensate volumes accounted for 92% and 90% of total oil and condensate volumes for the quarters ended September 30, 2019 and 2018, respectively.

Natural gas and natural gas liquids sales. Natural gas and NGL sales during the current quarter were lower than the third quarter of 2018 due to lower realized commodity prices partially offset by higher production volumes, largely in the Haynesville/Bossier play, as well as in the Permian Basin. Mineral and royalty interest production accounted for 71% and 60% of our natural gas volumes for the quarters ended September 30, 2019 and 2018, respectively.

Gain (loss) on commodity derivative instruments. During the third quarter of 2019, we recognized a gain from our commodity derivative instruments compared to a loss in the same period in 2018. Cash settlements we receive represent realized gains, while cash settlements we pay represent realized losses related to our commodity derivative instruments. In addition to cash settlements, we also recognize fair value changes on our commodity derivative instruments in each reporting period. The changes in fair value result from new positions and settlements that may occur during each reporting period, as well as the relationships between contract prices and the associated forward curves. The change in gain (loss) from our commodity derivative instruments between the comparative periods is due to realized and unrealized gains on our oil and natural gas commodity contracts in the third quarter of 2019 compared to realized and unrealized losses in the same period in 2018. For the three months ended September 30, 2019, we recognized $13.6 million of realized gains and $10.6 million of unrealized gains from our oil and natural gas commodity contracts, compared to $9.8 million of realized losses and $8.7 million of unrealized losses in the same period in 2018. The unrealized gains on our commodity contracts during the third quarter of 2019 and the unrealized losses in the same period in 2018 were primarily driven by changes in the forward commodity price curves for oil during each period.

Lease bonus and other income. When we lease our mineral interests, we generally receive an upfront cash payment, or a lease bonus. Lease bonus revenue can vary substantively between periods because it is derived from individual transactions with operators, some of which may be significant. Lease bonus and other income for the third quarter of 2019 was lower than the same period in 2018. Leasing activity in the Permian Basin and the Bakken/Three Forks trend made up the majority of lease bonus revenue in the third quarter of 2019, while a substantial portion of third quarter 2018 activity came from the Austin Chalk, Bakken/Three Forks, Marmaton and Wilcox/Yegua trends.

Operating and Other Expenses

Lease operating expense. Lease operating expense includes 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 slightly increased for the quarter ended September 30, 2019 as compared to the same period in 2018, primarily due to higher nonrecurring service-related expenses, including workovers, on wells in which we own a non-operating working interest.

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, 2019, production costs and ad valorem taxes decreased as compared to the quarter ended September 30, 2018, primarily as a result of decreased oil and condensate sales and natural gas and NGL sales.

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 was minimal for each of the three months ended September 30, 2019 and 2018.

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 decreased for the quarter ended September 30, 2019 as compared to the same period in 2018, primarily due to the impact of lower depletion rates partially offset by higher production volumes.

General and administrative. General and administrative expenses are costs not directly associated with the production of oil and natural gas and include expenses such as the cost of employee salaries and related benefits, office expenses, and fees for professional services. For the quarter ended September 30, 2019, general and administrative expenses decreased as compared to the same period in 2018, primarily due to lower costs associated with our incentive compensation plans. This change was driven by costs recognized in the prior comparative period on incentive compensation awarded in connection with our initial public offering in 2015 that fully vested in the first quarter of 2019, higher costs recognized in the prior comparative period due to projected overperformance relative to performance targets, and a decrease in our common unit price period over period.

Interest expense. Interest expense was lower in the third quarter of 2019 relative to the corresponding period in 2018 primarily due to lower interest rates under our Credit Facility.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

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

	Nine Months Ended September 30,			
	2019	2018	Variance	
	(Dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)	3,631	3,623	8	0.2 %
Natural gas (MMcf)[1]	59,025	52,205	6,820	13.1 %
Equivalents (MBoe)	13,469	12,324	1,145	9.3 %
Equivalents/day (MBoe)	49.3	45.1	4.2	9.3 %
Realized prices, without derivatives:				
Oil and condensate ($/Bbl)	$ 55.09	$ 64.29	$ (9.20)	(14.3)%
Natural gas ($/Mcf)[1]	2.65	3.26	(0.61)	(18.7)%
Equivalents ($/Boe)	$ 26.48	$ 32.71	$ (6.23)	(19.0)%
Revenue:				
Oil and condensate sales	$ 200,031	$ 232,920	$ (32,889)	(14.1)%
Natural gas and natural gas liquids sales[1]	156,622	170,179	(13,557)	(8.0)%
Lease bonus and other income	15,846	28,616	(12,770)	(44.6)%
Revenue from contracts with customers	372,499	431,715	(59,216)	(13.7)%
Gain (loss) on commodity derivative instruments	12,294	(68,194)	80,488	118.0 %
Total revenue	$ 384,793	$ 363,521	$ 21,272	5.9 %
Operating expenses:				
Lease operating expense	$ 13,497	$ 12,767	$ 730	5.7 %
Production costs and ad valorem taxes	44,919	46,939	(2,020)	(4.3)%
Exploration expense	372	6,782	(6,410)	(94.5)%
Depreciation, depletion, and amortization	84,933	88,135	(3,202)	(3.6)%
General and administrative	49,750	60,416	(10,666)	(17.7)%

[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 nine months ended September 30, 2019 increased compared to the corresponding prior period. The increase in total revenue is primarily due to a gain from our commodity derivative instruments for the nine months ended September 30, 2019, compared to a loss in the same period in 2018. The overall increase in total revenue was partially offset by decreases in oil and condensate sales, natural gas and NGL sales, and lease bonus and other income.

Oil and condensate sales. Oil and condensate sales during the nine months ended September 30, 2019 were lower than the nine months ended September 30, 2018 due to lower realized commodity prices. Our mineral and royalty interest oil and condensate volumes increased 3% in the nine months ended September 30, 2019 relative to the corresponding period in 2018, primarily driven by production increases in the Permian Basin. Our mineral and royalty interest oil and condensate volumes accounted for 92% and 90% of total oil and condensate volumes for the nine months ended September 30, 2019 and 2018, respectively.

Natural gas and natural gas liquids sales. Natural gas and NGL sales during the nine months ended September 30, 2019 were lower than the nine months ended September 30, 2018 due to lower realized commodity prices, partially offset by increased production volumes, largely in the Haynesville/Bossier play, as well as in the Permian Basin. Mineral and royalty interest production accounted for 68% and 59% of our natural gas volumes for the nine months ended September 30, 2019 and 2018, respectively.

Gain (loss) on commodity derivative instruments. During the nine months ended September 30, 2019, we recognized a gain from our commodity derivative instruments compared to a loss in the same period in 2018. The change in gain (loss) from our commodity derivative instruments between the comparative periods is due to realized gains and unrealized losses on our oil and natural gas commodity contracts resulting in a net gain on commodity derivatives in the nine months ended September 30, 2019 compared to realized and unrealized losses in the corresponding prior period. In the nine months ended September 30, 2019, we recognized $18.3 million of realized gains and $6.0 million of unrealized losses from our oil and natural gas commodity contracts, compared to $20.5 million of realized losses and $47.7 million of unrealized losses in the same period in 2018. The unrealized losses on our commodity contracts during the nine months ended September 30, 2019 were primarily driven by changes in the forward commodity price curves for oil, partially offset by changes in the forward commodity price curves for natural gas. The unrealized losses on our commodity contracts during the corresponding period in 2018 were primarily driven by changes in the forward commodity price curves for oil.

Lease bonus and other income. Lease bonus and other income for the nine months ended September 30, 2019 was lower than the same period in 2018. Leasing activity in the Permian Basin, as well as the Bakken/Three Forks, Wilcox, and Woodbine trends made up the majority of lease bonus revenue in the nine months ended September 30, 2019, while a substantial portion of the activity in the corresponding prior period came from the Permian Basin, as well as the Austin Chalk, Bakken/Three Forks, Canyon Lime, Douglas, Eagle Ford, Frio, Haynesville/Bossier, and Woodford trends.

Operating and Other Expenses

Lease operating expense. Lease operating expense increased for the nine months ended September 30, 2019 as compared to the same period in 2018, primarily due to higher nonrecurring service-related expenses, including workovers, on wells in which we own a non-operating working interest.

Production costs and ad valorem taxes. For the nine months ended September 30, 2019, production costs and ad valorem taxes decreased as compared to the nine months ended September 30, 2018, as a result of lower commodity prices, partially offset by increased oil and natural gas production volumes.

Exploration expense. Exploration expense for the nine months ended September 30, 2019 primarily consisted of costs incurred to acquire 3-D seismic information related to our mineral and royalty interests from a third-party service provider. Exploration expense for the nine months ended September 30, 2018 primarily related to the costs incurred on the Pepperjack B#1 well.

Depreciation, depletion, and amortization. Depreciation, depletion, and amortization decreased for the nine months ended September 30, 2019 as compared to the same period in 2018, primarily due to the impact of lower depletion rates partially offset by higher production volumes.

General and administrative. For the nine months ended September 30, 2019, general and administrative expenses decreased as compared to the same period in 2018, primarily due to lower costs associated with our incentive compensation plans. This change was driven by higher costs recognized in the prior comparative period on incentive compensation awarded in connection with our initial public offering in 2015 that fully vested in the first quarter of 2019, higher costs recognized in the prior comparative period due to projected overperformance relative to performance targets, and a decrease in our common unit price period over period.

Interest expense. Interest expense was higher in the nine months ended September 30, 2019 than in the prior period primarily due to increased outstanding borrowings partially offset by lower interest rates under our Credit Facility. Average outstanding borrowings during the nine months ended September 30, 2019 were higher than the nine months ended September 30, 2018 due to the funding of acquisitions in 2019 and 2018.

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 and debt. 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.

The Board has adopted a policy pursuant to which, at a minimum, distributions will be paid on each common unit for each quarter to the extent we have sufficient cash generated from our operations after establishment of cash reserves, if any, and after we have made the required distributions to the holders of our outstanding preferred units. However, we do not have a legal or contractual obligation to pay distributions on our common units quarterly or on any other basis, and there is no guarantee that we will pay distributions to our common unitholders in any quarter. The Board may change the foregoing distribution policy at any time and from time to time.

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 our executed farmout agreements and internally-generated cash flows, although at times we may fund a portion of these expenditures through other 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. Prior to the end of the subordination period, we were required by our partnership agreement to retain cash from our operations in an amount equal to our estimated replacement capital requirements. The Board established a replacement capital expenditure estimate of $13.0 million for the period of April 1, 2017 to March 31, 2018, and $11.0 million for the period of April 1, 2018 to March 31, 2019. No replacement capital expenditure estimate will be established for periods subsequent to March 31, 2019.

Cash Flows

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

	Nine Months Ended September 30,		
	2019	**2018**	**Change**
	(in thousands)		
Cash flows provided by operating activities	$ 306,310	$ 289,719	$ 16,591
Cash flows used in investing activities	(48,833)	(143,725)	94,892
Cash flows used in financing activities	(260,925)	(147,195)	(113,730)

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. The increase in cash flows from operations was primarily due to a net increase in cash flows from changes in operating assets and liabilities for the nine months ended September 30, 2019 compared to a net decrease for the same period of 2018 and net cash received on settlement of commodity derivative instruments for the nine months ended September 30, 2019 compared to net cash paid for the same period of 2018. The overall increase in cash flows from operations was partially offset by decreased oil and condensate sales and natural gas and NGL sales driven by lower realized commodity prices and decreased lease bonus and other income.

Investing Activities. Net cash used in investing activities decreased in the first nine months of 2019 as compared to the corresponding period in 2018. The decrease was primarily due to reduced oil and natural gas property acquisitions and expenditures.

Financing Activities. Cash flows used in financing activities for the nine months ended September 30, 2019 increased primarily due to increased distributions to common and subordinated unitholders, increased repurchases of common units, decreased net borrowings under our Credit Facility, and no common units sold under our at-the-market offering program during the current period.

Development Capital Expenditures

Our 2019 total development capital expenditure budget associated with our non-operated working interests is expected to be approximately $5.0 million, net of farmout reimbursements, of which $4.0 million has been invested in the nine months ended September 30, 2019. The majority of this capital will be spent for workovers on existing wells in which we own a working interest or for acquiring new leasehold acreage for subsequent farmout in the Haynesville/Bossier play.

Acquisitions

We spent approximately $43.0 million and issued common units valued at $0.9 million during the nine months ended September 30, 2019 related to acquisitions of mineral and royalty interests, which also included proved oil and natural gas properties. See Note 4 – Oil and Natural Gas Properties to our unaudited interim consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for further discussion.

Credit Facility

Pursuant to our $1.0 billion senior secured revolving credit agreement, as amended (the “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. Borrowings under the Credit Facility may be used for the acquisition of properties, cash distributions, and other general corporate purposes. Effective May 4, 2018, the borrowing base redetermination increased the borrowing base to $600.0 million. Effective October 31, 2018, the borrowing base was further increased to $675.0 million and remained at that level until the most recent redetermination, effective October 23, 2019, which reduced the borrowing base to $650.0 million. Our Credit Facility terminates on November 1, 2022. As of September 30, 2019, we had outstanding borrowings of $413.0 million at a weighted-average interest rate of 4.30%.

The borrowing base 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. We also 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 Credit Facility 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. Prior to October 31, 2018, the applicable margin ranged 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. Effective October 31, 2018, the applicable margin for the alternative base rate was reduced to between 0.75% and 1.75% and the applicable margin for LIBOR was reduced to between 1.75% and 2.75%.

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. Our Credit Facility is secured by substantially all of our oil and natural gas production and assets.

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 derivative 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 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 the 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, 2019, we were in compliance with all debt covenants.

Contractual Obligations

As of September 30, 2019, there have been no material changes to our contractual obligations previously disclosed in our 2018 Annual Report on Form 10-K.

Off-Balance Sheet Arrangements

As of September 30, 2019, we did not have any material off-balance sheet arrangements.

Critical Accounting Policies and Related Estimates

As of September 30, 2019, there have been no significant changes to our critical accounting policies and related estimates previously disclosed in our 2018 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 interim 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 NGLs 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 NGLs have been historically volatile, 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 – Commodity Derivative Financial Instruments and Note 6 – Fair Value Measurements to the unaudited interim consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for additional information.

To estimate the effect lower prices would have on our reserves, we reduced the SEC commodity pricing for the nine months ended September 30, 2019 by 10%. This results in an approximate 1.9% reduction of proved reserve volumes as compared to the unadjusted September 30, 2019 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, 2019, we had nine counterparties, all of which were rated Baa1 or better by Moody's and 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, 2019, we had $413.0 million of outstanding borrowings under our Credit Facility, bearing interest at a weighted-average interest rate of 4.3%. 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 $3.1 million for the nine months ended September 30, 2019, 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

Evaluation of 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, 2019.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended September 30, 2019 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 2018 Annual Report on Form 10-K. Except to the extent updated below, there has been no material change in our risk factors from those described in our 2018 Annual Report on Form 10-K. These risks, as updated below, 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.

Tax Risks to Common Unitholders

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial, or administrative changes and differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative, or judicial changes or differing interpretations at any time. From time to time, members of Congress propose and consider similar substantive changes to the existing U.S. federal income tax laws that would affect publicly traded partnerships, including elimination of partnership tax treatment for publicly traded partnerships. For example, the "Clean Energy for America Act", which is similar to legislation that was commonly proposed during the Obama Administration, was introduced in the Senate on May 2, 2019. If enacted, this proposal would, among other things, repeal Section 7704(d)(1)(E) of the Internal Revenue Code upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. There can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a partnership in the future.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted or adopted. Any such changes could negatively impact the value of an investment in our common units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your investment in our common units.

Risks Related to our Business

Cessation or protracted slowdowns of activity in the Shelby Trough area could adversely affect our results of operations.

In 2018, we generated 8.6% of our royalty revenues from two operators in the Shelby Trough area of the Haynesville play in East Texas, where we own a concentrated, relatively high-interest royalty position. These operators have recently decided to limit their Shelby Trough drilling activity, and one of the operators has released acreage in the area. Geographic and operator concentration heightens the effect of operational risks, including:

- operator's diversion of drilling capital to other areas, where our royalty interest is less meaningful or nonexistent;
- adverse changes to the operators' financial positions;
- unanticipated geographic or environmental constraints in the Shelby Trough; or
- delay or cancellation of construction or operation of LNG export facilities in the Gulf of Mexico.

If drilling activity in this area does not resume at the previous rate, production may decrease, reducing cash generated from operations and, without offsetting cost reductions, cash available for distribution.

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

Recent Sales of Unregistered Securities

None.

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., (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on May 6, 2015 (SEC File No. 001-37362)).
3.4	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 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on April 19, 2016 (SEC File No. 001-37362)).
3.5	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated as of November 28, 2017 (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on November 29, 2017 (SEC File No. 001-37362)).
3.6	Amendment No. 3 to First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated as of December 11, 2017 (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on December 12, 2017 (SEC File No. 001-37362)).
4.1	Registration Rights Agreement, dated as of November 28, 2017, by and between Black Stone Minerals, L.P. and Mineral Royalties One, L.L.C. (incorporated herein by reference to Exhibit 4.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on November 29, 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	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
*101.SCH	Inline XBRL Schema Document
*101.CAL	Inline XBRL Calculation Linkbase Document
*101.LAB	Inline XBRL Label Linkbase Document
*101.PRE	Inline XBRL Presentation Linkbase Document
*101.DEF	Inline XBRL Definition Linkbase Document
*104	Cover Page Interactive Data File - the cover page iXBRL tags are embedded within the Inline XBRL 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 5, 2019

By: /s/ Thomas L. Carter, Jr.
Thomas L. Carter, Jr.
Chief Executive Officer and Chairman
(Principal Executive Officer)

Date: November 5, 2019

By: /s/ Jeffrey P. Wood
Jeffrey P. Wood
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 5, 2019

/s/ Thomas L. Carter, Jr.

Thomas L. Carter, Jr.
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 5, 2019

/s/ Jeffrey P. Wood

Jeffrey P. Wood
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 5, 2019	/s/ Thomas L. Carter, Jr.
	Thomas L. Carter, Jr. Chief Executive Officer Black Stone Minerals GP, L.L.C., the general partner of Black Stone Minerals, L.P.
Date: November 5, 2019	/s/ Jeffrey P. Wood
	Jeffrey P. Wood Chief Financial Officer Black Stone Minerals GP, L.L.C., the general partner of Black Stone Minerals, L.P.