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, 2018

OR

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

For the transition period _______________ to _______________

Commission File Number: 001-37362

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

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

(713) 445-3200
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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. (Check one):

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

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

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

As of October 31, 2018, there were 108,465,215 common units, 96,328,836 subordinated units, and 14,711,219 Series B cumulative convertible preferred units of the registrant outstanding.

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PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

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

	September 30, 2018	December 31, 2017
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 4,441	$ 5,642
Accounts receivable	111,482	80,695
Commodity derivative assets	—	94
Prepaid expenses and other current assets	1,205	1,212
TOTAL CURRENT ASSETS	117,128	87,643
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, at cost, using the successful efforts method of accounting, includes unproved properties of $1,097,373 and $988,720 at September 30, 2018 and December 31, 2017, respectively	3,461,109	3,247,613
Accumulated depreciation, depletion, amortization, and impairment	(1,830,906)	(1,766,842)
Oil and natural gas properties, net	1,630,203	1,480,771
Other property and equipment, net of accumulated depreciation of $14,565 and $14,433 at September 30, 2018 and December 31, 2017, respectively	431	559
NET PROPERTY AND EQUIPMENT	1,630,634	1,481,330
DEFERRED CHARGES AND OTHER LONG-TERM ASSETS	6,497	7,478
TOTAL ASSETS	$ 1,754,259	$ 1,576,451
LIABILITIES, MEZZANINE EQUITY, AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 14,595	$ 2,464
Accrued liabilities	58,868	52,631
Commodity derivative liabilities	40,801	4,222
Other current liabilities	459	417
TOTAL CURRENT LIABILITIES	114,723	59,734
LONG–TERM LIABILITIES		
Credit facility	402,000	388,000
Accrued incentive compensation	1,496	3,648
Commodity derivative liabilities	11,966	1,263
Asset retirement obligations	14,669	14,092
Other long-term liabilities	92,096	19,171
TOTAL LIABILITIES	636,950	485,908
COMMITMENTS AND CONTINGENCIES (Note 8)		
MEZZANINE EQUITY		
Partners' equity – Series A redeemable convertible preferred units, zero and 26 units outstanding at September 30, 2018 and December 31, 2017, respectively	—	27,028
Partners' equity – Series B cumulative convertible preferred units, 14,711 and 14,711 units outstanding at September 30, 2018 and December 31, 2017, respectively	298,361	295,394
EQUITY		
Partners' equity – general partner interest	—	—
Partners' equity – common units, 108,330 and 103,456 units outstanding at September 30, 2018 and December 31, 2017, respectively	657,603	603,116
Partners' equity – subordinated units, 96,329 and 95,388 units outstanding at September 30, 2018 and December 31, 2017, respectively	160,638	164,138
Noncontrolling interests	707	867
TOTAL EQUITY	818,948	768,121
TOTAL LIABILITIES, MEZZANINE EQUITY, AND EQUITY	$ 1,754,259	$ 1,576,451

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,	
	2018	2017	2018	2017
REVENUE				
Oil and condensate sales	$ 82,712	$ 41,361	$ 232,920	$ 119,097
Natural gas and natural gas liquids sales	63,080	45,047	170,179	142,651
Lease bonus and other income	12,440	12,044	28,616	37,082
Revenue from contracts with customers	158,232	98,452	431,715	298,830
Gain (loss) on commodity derivative instruments	(18,514)	(9,341)	(68,194)	35,387
TOTAL REVENUE	139,718	89,111	363,521	334,217
OPERATING (INCOME) EXPENSE				
Lease operating expense	4,229	4,569	12,767	12,906
Production costs and ad valorem taxes	17,641	11,549	46,939	35,314
Exploration expense	34	8	6,782	616
Depreciation, depletion, and amortization	29,273	29,204	88,135	84,483
General and administrative	22,083	17,305	60,416	51,998
Accretion of asset retirement obligations	278	260	820	760
(Gain) loss on sale of assets, net	—	—	(2)	(931)
TOTAL OPERATING EXPENSE	73,538	62,895	215,857	185,146
INCOME (LOSS) FROM OPERATIONS	66,180	26,216	147,664	149,071
OTHER INCOME (EXPENSE)				
Interest and investment income	53	(9)	123	30
Interest expense	(5,518)	(4,172)	(15,319)	(11,660)
Other income (expense)	60	(1)	(1,046)	352
TOTAL OTHER EXPENSE	(5,405)	(4,182)	(16,242)	(11,278)
NET INCOME (LOSS)	60,775	22,034	131,422	137,793
Net (income) loss attributable to noncontrolling interests	(22)	20	(1)	27
Distributions on Series A redeemable preferred units	—	(666)	(25)	(2,452)
Distributions on Series B cumulative convertible preferred units	(5,250)	—	(15,750)	—
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON AND SUBORDINATED UNITS	$ 55,503	$ 21,388	$ 115,646	$ 135,368
ALLOCATION OF NET INCOME (LOSS):				
General partner interest	$ —	$ —	$ —	$ —
Common units	29,188	16,371	71,037	83,989
Subordinated units	26,315	5,017	44,609	51,379
	$ 55,503	$ 21,388	$ 115,646	$ 135,368
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON AND SUBORDINATED UNIT:				
Per common unit (basic)	$ 0.27	$ 0.16	$ 0.67	$ 0.86
Weighted average common units outstanding (basic)	106,706	101,623	105,254	97,777
Per subordinated unit (basic)	$ 0.27	$ 0.05	$ 0.46	$ 0.54
Weighted average subordinated units outstanding (basic)	96,329	95,388	96,021	95,269
Per common unit (diluted)	$ 0.27	$ 0.16	$ 0.67	$ 0.86
Weighted average common units outstanding (diluted)	106,706	101,623	105,254	97,777
Per subordinated unit (diluted)	$ 0.27	$ 0.05	$ 0.46	$ 0.54
Weighted average subordinated units outstanding (diluted)	96,329	95,388	96,021	95,269
DISTRIBUTIONS DECLARED AND PAID:				
Per common unit	$ 0.3375	$ 0.3125	$ 0.9625	$ 0.8875
Per subordinated unit	$ 0.3375	$ 0.2088	$ 0.7550	$ 0.5763

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

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

	Common units	Subordinated units	Partners' equity — common units	Partners' equity — subordinated units	Noncontrolling interests	Total equity
BALANCE AT DECEMBER 31, 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	(486)	(23)	(8,729)	(342)	—	(9,071)
Issuance of common units, net of offering costs	2,121	—	38,369	—	—	38,369
Issuance of common units for property acquisitions	1,227	—	22,530	—	—	22,530
Restricted units granted, net of forfeitures	1,276	—	—	—	—	—
Equity–based compensation	—	—	24,791	11,015	—	35,806
Distributions	—	—	(101,644)	(72,532)	(161)	(174,337)
Charges to partners' equity for accrued distribution equivalent rights	—	—	(2,365)	—	—	(2,365)
Distributions on Series A redeemable preferred units	—	—	(13)	(12)	—	(25)
Distributions on Series B cumulative convertible preferred units	—	—	(15,750)	—	—	(15,750)
Net income (loss)	—	—	86,800	44,621	1	131,422
BALANCE AT SEPTEMBER 30, 2018	108,330	96,329	$ 657,603	$ 160,638	$ 707	$ 818,948

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,	
	2018	**2017**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income (loss)	$ 131,422	$ 137,793
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, and amortization	88,135	84,483
Accretion of asset retirement obligations	820	760
Amortization of deferred charges	653	661
(Gain) loss on commodity derivative instruments	68,194	(35,387)
Net cash (paid) received on settlement of commodity derivative instruments	(20,461)	12,339
Equity-based compensation	24,947	18,614
Exploratory dry hole expense	6,784	—
Deferred rent	802	—
(Gain) loss on sale of assets, net	(2)	(931)
Changes in operating assets and liabilities:		
Accounts receivable	(29,989)	(709)
Prepaid expenses and other current assets	7	(234)
Accounts payable, accrued liabilities, and other	18,515	(5,610)
Settlement of asset retirement obligations	(108)	(113)
NET CASH PROVIDED BY OPERATING ACTIVITIES	289,719	211,666
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisitions of oil and natural gas properties	(106,390)	(89,030)
Additions to oil and natural gas properties	(119,676)	(38,346)
Additions to oil and natural gas properties leasehold costs	(4,639)	(2,334)
Purchases of other property and equipment	(15)	(118)
Proceeds from the sale of oil and natural gas properties	8,390	6,754
Proceeds from farmouts of oil and natural gas properties	78,605	6,592
NET CASH USED IN INVESTING ACTIVITIES	(143,725)	(116,482)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from issuance of common units, net of offering costs	38,369	31,267
Distributions to common and subordinated unitholders	(174,348)	(142,575)
Distributions to Series A redeemable preferred unitholders	(690)	(3,111)
Distributions to Series B cumulative convertible preferred unitholders	(12,425)	—
Distributions to noncontrolling interests	(161)	(90)
Redemptions of Series A redeemable preferred units	(2,115)	(19,641)
Repurchases of common and subordinated units	(9,071)	(7,845)
Borrowings under credit facility	264,500	208,500
Repayments under credit facility	(250,500)	(162,500)
Debt issuance costs and other	(754)	(50)
NET CASH USED IN FINANCING ACTIVITIES	(147,195)	(96,045)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(1,201)	(861)
CASH AND CASH EQUIVALENTS – beginning of the period	5,642	9,772
CASH AND CASH EQUIVALENTS – end of the period	$ 4,441	$ 8,911
SUPPLEMENTAL DISCLOSURE		
Interest paid	$ 14,607	$ 11,041

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 formed on September 16, 2014. On May 6, 2015, BSM completed its initial public offering (the “IPO”) of 22,500,000 common units representing limited partner interests at a price to the public of $19.00 per common unit. BSM received proceeds of $391.5 million from the sale of its common units, net of underwriting discount, structuring fee, and offering expenses (including costs previously incurred and capitalized). BSM used the net proceeds from the IPO to repay substantially all indebtedness outstanding under its Credit Facility, as defined in Note 7 – Credit Facility. On May 1, 2015, BSM’s common units began trading on the New York Stock Exchange under the symbol “BSM.”

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

In addition to mineral interests, which make up the vast majority of the asset base, the Partnership’s assets also include nonparticipating and overriding royalty interests. These interests, which are non-cost-bearing, are collectively referred to as “mineral and royalty interests.” As of September 30, 2018, the Partnership’s mineral and royalty interests were located in 41 states and 64 onshore oil and natural gas producing basins of the continental U.S., including all of the major onshore producing basins. The Partnership also owns non-operated working interests in certain oil and natural gas properties.

Basis of Presentation

The accompanying unaudited interim consolidated financial statements of the Partnership have been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP") and pursuant to the rules and regulations of the U.S. Securities and Exchange Commission (“SEC”). These unaudited interim consolidated financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with U.S. GAAP. Accordingly, the accompanying unaudited interim consolidated financial statements and related notes should be read in conjunction with the Partnership’s consolidated financial statements included in the Partnership’s 2017 Annual Report on Form 10-K.

The financial statements include the consolidated results of the Partnership. The results of operations for the nine months ended September 30, 2018 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. Certain reclassifications have been made to the prior periods presented to conform to the current period financial statement presentation. The reclassifications have no effect on the consolidated financial position, results of operations, or cash flows of the Partnership.

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

The 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 Annual Report on Form 10-K for the year ended December 31, 2017. There have been no changes in such policies or the application of such policies during the nine months ended September 30, 2018, with the exception of ASC 606, as defined below.

Accounts Receivable

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

	September 30, 2018	December 31, 2017
	(in thousands)	
Accounts receivable:		
Revenues from contracts with customers	$ 106,634	$ 77,544
Other	4,848	3,151
Total accounts receivable	$ 111,482	$ 80,695

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2014-09, *Revenue from Contracts with Customers (Topic 606)* that supersedes Accounting Standards Codification ("ASC") 605, *Revenue Recognition*. Under the new standard, entities are required to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services, which may require more judgment than under previous U.S. GAAP. See Note 3 – Impact of ASC 606 Adoption for further details related to the Partnership’s adoption of this standard.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, which will supersede the lease requirements in Topic 840, *Leases* by requiring lessees to recognize lease assets and lease liabilities classified as operating leases on the balance sheet. The new lease standard will be effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, and early adoption is permitted.

The FASB recently issued ASU 2018-11, *Leases (Topic 842), Targeted Improvements*, which would allow entities to apply the transition provisions of the new standard at the adoption date instead of at the earliest comparative period presented in the consolidated financial statements, and will also allow entities to continue to apply the legacy guidance in Topic 840, including disclosure requirements, in the comparative period presented in the year the new leases standard is adopted. Entities that elect this option would still adopt the new leases standard using a modified retrospective transition method, but would recognize a cumulative catch-up adjustment in the period of adoption rather than in the earliest period presented. The Partnership plans to use a modified retrospective transition method to apply the new standard to leases that exist as of the adoption date of January 1, 2019. The Partnership does not plan to early adopt.

Based on evaluations to-date, the new guidance will not have a material impact on the Partnership's consolidated financial statements and related disclosures as this guidance does not apply to leases to explore for or use minerals, oil, natural gas, and similar resources.

In August 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 606 ADOPTION

ASC 606, *Revenue from Contracts with Customers*, requires the Partnership to identify the distinct promised goods and services within a contract which represent separate performance obligations and determine the transaction price to allocate to the performance obligations identified. The Partnership adopted ASC 606 using the modified retrospective method, which was applied to all existing contracts for which all (or substantially all) of the revenue had not been recognized under legacy revenue guidance as of the date of adoption, January 1, 2018.

Revenues from Contracts with Customers

Oil and natural gas sales

Sales of oil and natural gas are recognized at the point control of the product is transferred to the customer and collectability of the sales price is reasonably assured. Oil is priced on the delivery date based upon prevailing prices published by purchasers with certain adjustments related to oil quality and physical location. The price the Partnership receives for natural gas is tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality and heat content of natural gas, and prevailing supply and demand conditions, so that the price of natural gas fluctuates to remain competitive with other available natural gas supplies. As each unit of product represents a separate performance obligation and the consideration is variable as it relates to oil and natural gas prices, we recognize revenue from oil and natural gas sales using the practical expedient for variable consideration in ASC 606.

Lease bonus and other income

The Partnership also earns revenue from lease bonuses and delay rentals. The Partnership generates lease bonus revenue by leasing its mineral interests to exploration and production companies. A lease agreement represents the Partnership's contract with a customer and generally transfers the rights to any oil or natural gas discovered, grants the Partnership a right to a specified royalty interest, and requires that drilling and completion operations commence within a specified time period. Control is transferred to the lessee and the Partnership has satisfied its performance obligation when the lease agreement is executed, such that revenue is recognized when the lease bonus payment is received. At the time the Partnership executes the lease agreement, the Partnership expects to receive the lease bonus payment within a reasonable time, though in no case more than one year, such that the Partnership has not adjusted the expected amount of consideration for the effects of any significant financing component per the practical expedient in ASC 606. The Partnership also recognizes revenue from delay rentals to the extent drilling has not started within the specified period, payment has been received, and the Partnership has no further obligation to refund the payment.

Production imbalances

The Partnership previously elected to utilize the entitlements method to account for natural gas production imbalances, which is no longer permitted under ASC 606. As of January 1, 2018, these amounts were de minimis. As such, upon adoption of ASC 606, there was no material impact to the financial statements due to this change in accounting for the Partnership's production imbalances.

Allocation of transaction price to remaining performance obligations

Oil and natural gas sales

The Partnership has utilized the practical expedient in ASC 606 which states the Partnership is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. As the Partnership has determined that each unit of product generally represents a separate performance obligation, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Lease bonus and other income

Given that the Partnership does not recognize lease bonus or other income until a lease agreement has been executed, at which point its performance obligation has been satisfied, and payment is received, the Partnership does not record revenue for unsatisfied or partially unsatisfied performance obligations as of the end of the reporting period. Overall, there were no material changes in the timing of the satisfaction of the Partnership's performance obligations or the allocation of the transaction price to its performance obligations in applying the guidance in ASC 606 as compared to legacy U.S. GAAP.

Prior-period performance obligations

The Partnership records revenue in the month production is delivered to the purchaser. As a non-operator, the Partnership has limited visibility into the timing of when new wells start producing and production statements may not be received for 30 to 90 days or more after the date production is delivered. As a result, the Partnership is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. The expected sales volumes and prices for these properties are estimated and recorded within the Accounts receivable line item in the accompanying consolidated balance sheets. The difference between the Partnership's estimates and the actual amounts received for oil and natural gas sales is recorded in the month that payment is received from the third party. For the three and nine months ended September 30, 2018, revenue recognized in the reporting periods related to performance obligations satisfied in prior reporting periods was immaterial.

NOTE 4 — OIL AND NATURAL GAS PROPERTIES ACQUISITIONS

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

2018 Acquisitions

During the nine months ended September 30, 2018, the Partnership closed on multiple acquisitions of mineral and royalty interests for total consideration of $132.1 million.

Acquisitions that included proved oil and natural gas properties were considered business combinations and were primarily located in the Permian Basin. The cash portion of the consideration paid for these acquisitions was funded with borrowings under the Partnership's Credit Facility and funds from operating activities. Acquisition related costs of $0.1 million were expensed and included in the General and administrative expense line item of the consolidated statement of operations for the nine months ended September 30, 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	—
Total fair value	$ 12,392	$ 77,757	$ 430	$ 90,579	$ 68,549	$ 22,030

In addition, during the nine months ended September 30, 2018, the Partnership acquired mineral and royalty interests in unproved oil and natural gas properties from various sellers for an aggregate of $41.5 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 $41.0 million was funded with borrowings under the Partnership's Credit Facility and funds from operating activities, and $0.5 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.

Noble Acquisition

On November 28, 2017 (the "Close Date"), BSMC closed on the acquisition of (i) certain mineral interests and other non-cost bearing royalty interests from Noble Energy Inc., Noble Energy Wyco, LLC, and Rosetta Resources Operating LP and (ii) one hundred percent (100%) of the issued and outstanding securities of Samedan Royalty, LLC ("Samedan") from Noble Energy US Holdings, LLC, collectively, the "Noble Acquisition."

The mineral interests and other non-cost bearing royalty interests acquired in the Noble Acquisition, including interests owned by Samedan (the "Noble Assets") include approximately 1.1 million gross (140,000 net) mineral acres, 380,000 gross acres of non-participating royalty interests, and 600,000 gross acres of overriding royalty interests collectively spread over 20 states with significant concentrations in Texas, Oklahoma, and North Dakota.

The Partnership funded the $335.0 million purchase price (before customary post-closing adjustments) using (i) approximately $300.0 million in proceeds from its issuance of 14,711,219 Series B cumulative convertible preferred units to Mineral Royalties One, L.L.C., an affiliate of The Carlyle Group (the "Purchaser"), in a private placement which also closed on November 28, 2017, and (ii) approximately $35.0 million from borrowings under its Credit Facility. See additional discussion of the Series B cumulative convertible preferred units in Note 10 – Preferred Units.

The transaction was accounted for as a business combination using the acquisition method of accounting which requires, among other things, that the assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date. The final determination of fair value remains preliminary and will be completed after post-closing purchase price adjustments are finalized, but in no case later than one year from the acquisition date. Since December 31, 2017, the Partnership has recorded an adjustment to the purchase price to reduce the amount allocated to unproved properties by $3.2 million, which reduces the Acquisitions of oil and natural gas properties line item of the consolidated statement of cash flows for the nine months ended September 30, 2018.

The following table summarizes the adjusted allocation of the fair value of the assets acquired and the acquisition-related costs as of September 30, 2018:

	Assets Acquired					
	Proved	**Unproved**	**Net Working Capital**	**Total Fair Value**	**Cash Consideration Paid[1]**	**Acquisition-Related Costs[2]**
			(in thousands)			
Noble Assets	$ 68,877	$ 256,542	$ 5,917	$ 331,336	$ 331,336	$ 247

[1] Represents cash consideration paid on the Close Date, as adjusted for the $3.2 million purchase price adjustment recorded during the nine months ended September 30, 2018.

[2] Acquisition-related costs were expensed and included in the General and administrative expense line item of the consolidated statement of operations for the year ended December 31, 2017.

The fair value of the Noble Assets was measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of: (i) oil and natural gas reserves; (ii) future commodity prices; (iii) estimated future cash flows; and (iv) market-based weighted average cost of capital. These inputs require significant judgments and estimates by the Partnership's management at the time of the valuation and are the most sensitive and subject to change.

Actual and Pro Forma Impact of Noble Acquisition (Unaudited)

Revenue attributable to the Noble Acquisition included in the Partnership's consolidated statements of operations for the three and nine months ended September 30, 2018 was $15.7 million and $41.3 million, respectively. The following table presents unaudited pro forma information for the Partnership as if the Noble Acquisition occurred on January 1, 2017.

	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017
	(in thousands, except per unit amounts)	
Revenue and other income	$ 98,962	$ 363,051
Net income	27,449	154,175
Net income attributable to noncontrolling interests	20	27
Distributions on Series A redeemable preferred units	(666)	(2,452)
Distributions on Series B cumulative convertible preferred units	(5,250)	(15,750)
Net income attributable to the general partner and common and subordinated units	$ 21,553	$ 136,000
Allocation of net income:		
General partner interest	$ —	$ —
Common units	16,168	84,321
Subordinated units	5,385	51,679
	$ 21,553	$ 136,000
Net income attributable to limited partners per common and subordinated unit:		
Per common unit (basic)	$ 0.16	$ 0.86
Per subordinated unit (basic)	$ 0.06	$ 0.54
Per common unit (diluted)	$ 0.16	$ 0.86
Per subordinated unit (diluted)	$ 0.06	$ 0.54

The historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the Noble Acquisition and are factually supportable. The unaudited pro forma consolidated results are not necessarily indicative of what the Partnership's consolidated results of operations would have been had the acquisition been completed on January 1, 2017. In addition, the unaudited pro forma consolidated results do not purport to project the future results of operations for the combined company.

The unaudited pro forma consolidated results reflect the following pro forma adjustments for the periods presented:

- Adjustments to recognize incremental revenue, production costs and ad valorem taxes, and depreciation, depletion, and amortization expense attributable to the Noble Assets.
- Adjustment to recognize additional interest expense associated with the incremental borrowings under the Partnership's Credit Facility.
- Adjustment to recognize the quarterly distribution associated with the issuance of 14,711,219 Series B cumulative convertible preferred units.
- The Series B cumulative convertible preferred units were not included in the calculation of pro forma diluted earnings per common unit for the three months ended September 30, 2017 as they were anti-dilutive under the if-converted method.
- The Series B cumulative convertible preferred units were included in the calculation of pro forma diluted earnings per common unit for the nine months ended September 30, 2017 due to their dilutive effect under the if-converted method.
- The Series B cumulative convertible preferred units do not have any impact to earnings per subordinated unit.

2017 Acquisitions

In addition to the Noble Acquisition, the Partnership closed on multiple acquisitions of mineral and royalty interests during the year ended December 31, 2017 for total consideration of $163.0 million.

Acquisitions that included proved oil and natural gas properties were considered business combinations and were primarily located in the Delaware Basin and East Texas. The cash portion of the consideration paid for these acquisitions was funded with borrowings under the Partnership's Credit Facility and funds from operating activities. 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	Acquisition-Related Costs[1]
	(in thousands)						
January	$ 5,135	$ 34,008	$ 263	$ 39,406	$ 27,380	$ 12,026	$ 1,162
June	5,006	45,477	—	50,483	4,802	45,681	1,481
August	3,277	9,984	—	13,261	4,289	8,972	107
September	3,120	—	—	3,120	3,120	—	—
Total fair value	$ 16,538	$ 89,469	$ 263	$ 106,270	$ 39,591	$ 66,679	$ 2,750

[1] Acquisition-related costs were expensed and included in the General and administrative expense line item of the consolidated statement of operations for the year ended December 31, 2017.

Additionally, during the year ended December 31, 2017, the Partnership acquired mineral and royalty interests in unproved oil and natural gas properties from various sellers for $56.7 million. These acquisitions were considered asset acquisitions and were primarily located in East Texas. The cash portion of the consideration paid for these acquisitions of $51.7 million was funded with borrowings under the Partnership's Credit Facility and funds from operating activities, and $5.0 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.

Farmout Agreements

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/Bossier acreage in San Augustine County, Texas operated by XTO Energy Inc. The Partnership has an approximate 50% working interest in the acreage and is the largest mineral owner. At its option, during the first three phases of the agreement, Canaan can commit on a phase-by-phase basis to fund a portion of the Partnership's drilling and completion costs to earn a percentage of the Partnership's working interest in wells drilled and completed during each phase. After the third phase, Canaan can earn a percentage of the Partnership's working interest in additional wells drilled in the area by committing on a well-by-well basis to fund a portion of the Partnership's costs for each well. The Partnership will receive an overriding royalty interest (“ORRI”) before payout and an increased ORRI after payout on all wells drilled under the agreement.

Since the inception of the agreement, the Partnership has received $62.2 million from Canaan under the agreement. All amounts received are included in the Other long-term liabilities line item of the September 30, 2018 consolidated balance sheet, as no working interest had been assigned to Canaan as of that date. Subsequent to September 30, 2018, the Partnership assigned to Canaan working interests in wells drilled and completed during the initial phase, reducing the Other long-term liabilities balance associated with the Canaan farmout agreement.

Pivotal Farmout

On November 21, 2017, the Partnership entered into a farmout agreement with a portfolio company of Tailwater Capital, LLC, Pivotal Petroleum Partners (“Pivotal”), that covers substantially all of the Partnership's remaining working interests under active development in the Shelby Trough area of East Texas targeting its Haynesville/Bossier acreage after giving effect to the Canaan Farmout (discussed above) over the next eight years. In wells operated by XTO Energy Inc. in San Augustine County, Texas, Pivotal will earn the Partnership's remaining working interest not covered by the Canaan Farmout, as well as the Partnership's working interests in wells operated by its other major operator in the area. After the funding of a designated group of wells by Pivotal and once Pivotal achieves a specified payout for such well group, the Partnership will obtain a majority of the original working interest in the designated group of wells.

Since the inception of the agreement, the Partnership has received $35.5 million from Pivotal under the agreement. As of September 30, 2018, the Partnership had assigned to Pivotal working interests in wells drilled and completed during the initial phase, and as such, only $27.5 million is included in the Other long-term liabilities line item of the consolidated balance sheet.

As of December 31, 2017, all amounts received from Canaan and Pivotal under the agreements were included in the Other long-term liabilities line item of the consolidated balance sheet, as no working interest had been assigned to Canaan or Pivotal as of that date.

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 derivative 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, 2018, 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, any changes in the fair value of the contracts are included in the consolidated statement of operations in the period of the change. All derivative gains and losses from the Partnership's derivative contracts have been recognized in revenue in the Partnership's accompanying consolidated statements of operations. Derivative instruments that have not yet been settled in cash are reflected as either derivative assets or liabilities in the Partnership's accompanying consolidated balance sheets as of September 30, 2018 and December 31, 2017. 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. 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, 2018, the Partnership had ten counterparties, all of which are rated Baa1 or better by Moody's. Nine of the Partnership's counterparties are lenders under the Credit Facility. The Partnership would have been at risk of losing a fair value amount of $6.2 million had the Partnership's counterparties as a group been unable to fulfill their obligations as of September 30, 2018.

The tables below summarize the fair values and classifications of the Partnership's derivative instruments as of each date:

		September 30, 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	$ 1,923	$ (1,923)	$ —
Long-term asset	Deferred charges and other long-term assets	4,253	(4,247)	6
Total assets		$ 6,176	$ (6,170)	$ 6
Liabilities:				
Current liability	Commodity derivative liabilities	$ 42,724	$ (1,923)	$ 40,801
Long-term liability	Commodity derivative liabilities	16,213	(4,247)	11,966
Total liabilities		$ 58,937	$ (6,170)	$ 52,767

		As of December 31, 2017		
Classification	**Balance Sheet Location**	**Gross Fair Value**	**Effect of Counterparty Netting**	**Net Carrying Value on Balance Sheet**
			(in thousands)	
Assets:				
Current asset	Commodity derivative assets	$ 10,713	$ (10,619)	$ 94
Long-term asset	Deferred charges and other long-term assets	1,392	(1,029)	363
Total assets		$ 12,105	$ (11,648)	$ 457
Liabilities:				
Current liability	Commodity derivative liabilities	$ 14,841	$ (10,619)	$ 4,222
Long-term liability	Commodity derivative liabilities	2,292	(1,029)	1,263
Total liabilities		$ 17,133	$ (11,648)	$ 5,485

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 are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Derivatives not designated as hedging instruments	**2018**	**2017**	**2018**	**2017**
Beginning fair value of commodity derivative instruments	$ (44,043)	$ 20,650	$ (5,028)	$ (16,719)
Gain (loss) on oil derivative instruments	(18,830)	(9,493)	(63,325)	18,306
Gain (loss) on natural gas derivative instruments	316	152	(4,869)	17,081
Net cash paid (received) on settlements of oil derivative instruments	11,280	(4,026)	25,809	(10,682)
Net cash paid (received) on settlements of natural gas derivative instruments	(1,484)	(954)	(5,348)	(1,657)
Net change in fair value of commodity derivative instruments	(8,718)	(14,321)	(47,733)	23,048
Ending fair value of commodity derivative instruments	$ (52,761)	$ 6,329	$ (52,761)	$ 6,329

The Partnership had the following open derivative contracts for oil as of September 30, 2018:

			Range (Per Bbl)	
Period and Type of Contract	**Volume (Bbl)**	**Weighted Average Price (Per Bbl)**	**Low**	**High**
Oil Swap Contracts:				
2018				
Third Quarter	283,000	$ 55.31	$ 51.85	$ 61.88
Fourth Quarter	854,000	55.18	51.85	61.88
2019				
First Quarter	645,000	$ 58.66	$ 52.82	$ 65.58
Second Quarter	645,000	58.66	52.82	65.58
Third Quarter	645,000	58.20	52.82	63.75
Fourth Quarter	645,000	58.20	52.82	63.75

Period and Type of Contract	**Volume (Bbl)**	**Weighted Average Floor Price (Per Bbl)**	**Weighted Average Ceiling Price (Per Bbl)**
Oil Collar Contracts:			
2019			
First Quarter	60,000	$ 65.00	$ 74.00
Second Quarter	60,000	65.00	74.00
Third Quarter	60,000	65.00	74.00
Fourth Quarter	60,000	65.00	74.00
2020			
First Quarter	210,000	$ 55.00	$ 70.85
Second Quarter	210,000	55.00	70.85
Third Quarter	210,000	55.00	70.85
Fourth Quarter	210,000	55.00	70.85

The Partnership had the following open derivative contracts for natural gas as of September 30, 2018:

Period and Type of Contract	Volume (MMBtu)	Weighted Average Price (Per MMBtu)	Range (Per MMBtu) Low	Range (Per MMBtu) High
Natural Gas Swap Contracts:				
2018				
Fourth Quarter	13,630,000	$ 3.01	$ 2.90	$ 3.23
2019				
First Quarter	7,200,000	$ 2.86	$ 2.81	$ 2.93
Second Quarter	7,240,000	2.86	2.81	2.93
Third Quarter	7,280,000	2.86	2.81	2.93
Fourth Quarter	7,280,000	2.86	2.81	2.93

Subsequent to September 30, 2018, the Partnership entered into gas derivative contracts for an average of 608,333 MMBtu per month in 2019 at a weighted average price of $2.85 per MMBtu.

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, 2018 or the year ended December 31, 2017.

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, 2018 and December 31, 2017 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, 2018					
Financial Assets					
Commodity derivative instruments	$ —	$ 6,176	$ —	$ (6,170)	$ 6
Financial Liabilities					
Commodity derivative instruments	$ —	$ 58,937	$ —	$ (6,170)	$ 52,767
As of December 31, 2017					
Financial Assets					
Commodity derivative instruments	$ —	$ 12,105	$ —	$ (11,648)	$ 457
Financial Liabilities					
Commodity derivative instruments	$ —	$ 17,133	$ —	$ (11,648)	$ 5,485

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

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

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

Oil and natural gas properties are measured at fair value on a nonrecurring basis using the income approach when assessing for impairment. Proved and unproved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of those properties. When assessing producing properties for impairment, the Partnership compares the expected undiscounted projected future cash flows of the producing properties to the carrying amount of the producing properties to determine recoverability. When the carrying amount exceeds its estimated undiscounted future cash flows, the carrying amount is written down to its fair value, which is measured as the present value of the projected future cash flows of such properties. The factors used to determine fair value include estimates of proved reserves, future commodity prices, timing of future production, 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, 2018 or December 31, 2017.

There were no assets measured at fair value on a nonrecurring basis, after initial recognition, for the three and nine months ended September 30, 2018 and 2017.

NOTE 7 — CREDIT FACILITY

The Partnership maintains a senior secured revolving credit agreement, as amended (the “Credit Facility”). The Credit Facility has a maximum credit amount of $1.0 billion. The amount of the borrowing base is derived from the value of the Partnership’s oil and natural gas properties as determined by the lender syndicate using pricing assumptions that often differ from the current market for future prices. The borrowing base is redetermined semi-annually, usually in October and April.

Effective April 25, 2017, the borrowing base redetermination increased the borrowing base from $500.0 million to $550.0 million. On November 1, 2017, the Partnership amended and restated the credit agreement to create a swingline facility that permits short-term borrowings on same-day notice, make other changes to the hedging and restrictive covenants, and extend the maturity for a term of five years, which terminates on November 1, 2022. Effective May 4, 2018, the borrowing base was increased to $600.0 million and, effective October 31, 2018, the borrowing base was further increased to $675.0 million.

Borrowings under the Credit Facility bear interest at LIBOR plus a margin between 2.00% and 3.00%, or the Prime Rate plus a margin between 1.00% and 2.00%, with the margin depending on the borrowing base utilization. Effective October 31, 2018, the LIBOR margin was reduced to between 1.75% and 2.75% and the Prime Rate margin was reduced to between 0.75% and 1.75%.

The weighted-average interest rate of the Credit Facility was 4.75% and 4.06% as of September 30, 2018 and December 31, 2017, respectively. Accrued interest is payable at the end of each calendar quarter or at the end of each interest period, unless the interest period is longer than 90 days, in which case interest is payable at the end of every 90-day period. In addition, a commitment fee is payable at the end of each calendar quarter based on either a rate of 0.375% if the borrowing base utilization percentage is less than 50%, or 0.500% per annum if the borrowing base utilization percentage is equal to or greater than 50%. The Credit Facility is secured by substantially all of the Partnership’s producing properties.

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, 2018, the Partnership was in compliance with all financial covenants in the Credit Facility.

The aggregate principal balance outstanding was $402.0 million and $388.0 million at September 30, 2018 and December 31, 2017, respectively. The unused portion of the available borrowings under the Credit Facility was $198.0 million and $162.0 million at September 30, 2018 and December 31, 2017, 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, now NAMP Holdings, LLC, on November 28, 2017 as part of the Noble Acquisition, 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 47.34% and 44.39% of the minerals interests held of record by Holdings and Temin, respectively. 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, 2018, the Partnership had not received notice from any co-owner 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, 2018 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 general and administrative expenses in the consolidated statements of operations for the three and nine months ended September 30, 2018 and 2017:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)			
Cash—short and long-term incentive plans	$ 4,366	$ 1,017	$ 7,568	$ 2,995
Equity-based compensation—restricted common and subordinated units	3,404	3,364	10,180	10,246
Equity-based compensation—restricted performance units	5,611	3,767	13,026	6,710
Board of Directors incentive plan	581	544	1,741	1,658
Total incentive compensation expense	$ 13,962	$ 8,692	$ 32,515	$ 21,609

NOTE 10 — PREFERRED UNITS

Series A Redeemable Preferred Units

As of September 30, 2018, there were no Series A redeemable preferred units outstanding, while as of December 31, 2017 there were 26,363 Series A redeemable preferred units outstanding with a carrying value of $27.0 million. This carrying value included accrued distributions of $0.7 million. The Series A redeemable preferred units are classified as mezzanine equity on the consolidated balance sheets since redemption was outside the control of the Partnership. 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, which reflects the reverse split described in Note 1 – Business and Basis of Presentation and the capital restructuring related to the IPO.

For the year ended December 31, 2017, 19,704 Series A redeemable preferred units were redeemed for $20.2 million, including accrued unpaid yield. For the year ended December 31, 2017, 6,624 Series A redeemable preferred units totaling $6.6 million were converted into 200,996 common units and 263,247 subordinated units as a result of the mandatory conversion subsequent to December 31, 2016.

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 to the Purchaser for a cash purchase price of $20.3926 per Series B cumulative convertible preferred unit, resulting in total proceeds of approximately $300 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, 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 and $295.4 million, including accrued distributions of $5.3 million and $1.9 million, as of September 30, 2018 and December 31, 2017, respectively. 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 and subordinated units have all the rights of a unitholder, including non-forfeitable distribution rights. As participating securities, the restricted common and subordinated units are included in the calculation of basic earnings per unit. For the periods presented, the amount of earnings allocated to these participating units was not material.

Net income (loss) attributable to the Partnership is allocated to the Partnership’s general partner and the common and subordinated unitholders in proportion to their pro rata ownership after giving effect to distributions, if any, declared during the period. The Series B cumulative convertible preferred units could be converted into approximately 15.0 million common units as of September 30, 2018.

At September 30, 2018, if the outstanding Series B cumulative convertible preferred units were converted to common units, the effect would be anti-dilutive; therefore, they are not included in the calculation of diluted EPU for the three and nine months ended September 30, 2018.

The Partnership’s restricted performance unit awards are contingently issuable units that are considered in the calculation of diluted EPU. The Partnership assesses the number of units that would be issuable, if any, under the terms of the arrangement if the end of the reporting period were the end of the contingency period. At September 30, 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,	
	2018	2017	2018	2017
	(in thousands, except per unit amounts)			
NET INCOME (LOSS)	$ 60,775	$ 22,034	$ 131,422	$ 137,793
Net (income) loss attributable to noncontrolling interests	(22)	20	(1)	27
Distributions on Series A redeemable preferred units	—	(666)	(25)	(2,452)
Distributions on Series B cumulative convertible preferred units	(5,250)	—	(15,750)	—
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON AND SUBORDINATED UNITS	$ 55,503	$ 21,388	$ 115,646	$ 135,368
ALLOCATION OF NET INCOME (LOSS):				
General partner interest	$ —	$ —	$ —	$ —
Common units	29,188	16,371	71,037	83,989
Subordinated units	26,315	5,017	44,609	51,379
	$ 55,503	$ 21,388	$ 115,646	$ 135,368
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON AND SUBORDINATED UNIT:				
Per common unit (basic)	$ 0.27	$ 0.16	$ 0.67	$ 0.86
Weighted average common units outstanding (basic)	106,706	101,623	105,254	97,777
Per subordinated unit (basic)	$ 0.27	$ 0.05	$ 0.46	$ 0.54
Weighted average subordinated units outstanding (basic)	96,329	95,388	96,021	95,269
Per common unit (diluted)	$ 0.27	$ 0.16	$ 0.67	$ 0.86
Weighted average common units outstanding (diluted)	106,706	101,623	105,254	97,777
Per subordinated unit (diluted)	$ 0.27	$ 0.05	$ 0.46	$ 0.54
Weighted average subordinated units outstanding (diluted)	96,329	95,388	96,021	95,269

NOTE 12 — AT-THE-MARKET OFFERING PROGRAM

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

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

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

Common units sold pursuant to the Equity Distribution Agreement are offered and sold pursuant to the Partnership's existing effective shelf-registration statement on Form S-3 (File No. 333-215857), which was declared effective by the 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, 2018, the Partnership sold 2,121,643 common units under the ATM Program for net proceeds of $38.4 million. As of September 30, 2018, the Partnership has raised net proceeds of $70.9 million under the ATM Program.

NOTE 13 — SUBSEQUENT EVENTS

Effective October 31, 2018, the borrowing base of the Credit Facility was increased to $675.0 million from $600.0 million and the applicable margin rates were reduced, as discussed in Note 7 - Credit Facility.

On October 26, 2018, the Board of Directors of the Partnership's general partner approved a distribution for the three months ended September 30, 2018 of $0.37 per common unit and $0.37 per subordinated unit. Distributions will be payable on November 21, 2018 to unitholders of record at the close of business on November 14, 2018.

On November 5, 2018, the Board authorized a $75.0 million unit repurchase program. The unit 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 repurchase program does not obligate the Partnership to acquire any particular amount of common units and may be modified or suspended at any time and could be terminated prior to completion. The program will be funded from the Partnership's cash on hand or through borrowings under the credit facility. Any repurchased units will be canceled.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our unaudited consolidated financial statements and notes thereto presented in this Quarterly Report on Form 10-Q, as well as our audited financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2017. This discussion and analysis contains forward-looking statements that involve risks, uncertainties, and assumptions. Actual results may differ materially from those anticipated in these forward-looking statements as a result of a number of factors, including those set forth under "Cautionary Note Regarding Forward-Looking Statements" and "Part II, Item 1A. Risk Factors."

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

Cautionary Note Regarding Forward-Looking Statements

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

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

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

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

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

Overview

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

As of September 30, 2018, our mineral and royalty interests were located in 41 states and 64 onshore basins in the continental United States. These non-cost-bearing interests include ownership in over 55,000 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 2018, we acquired mineral and royalty interests primarily in the Permian Basin and in East Texas for aggregate consideration of $109.6 million in cash and $22.5 million in our common units. Additional information regarding acquisitions is contained in Note 4 – Oil and Natural Gas Properties Acquisitions to our unaudited consolidated financial statements included herein for further discussion.

PepperJack Prospect

We have cumulatively spent approximately $13.1 million to drill two wells within our PepperJack prospect in Hardin and Liberty counties, Texas. The PepperJack A#1 well targeting the Lower Wilcox formation was drilled during the fourth quarter of 2017 and the first quarter of 2018. The PepperJack B#1 well, also targeting the Lower Wilcox formation, was drilled during the second quarter of 2018 to further delineate the prospect.

Based on the log results, we believe the PepperJack A#1 well is highly prospective and will be completed as a commercially productive well. The PepperJack B#1 well, which was a significant step-out from the PepperJack A#1 well, is not likely to be completed in the near term. Accordingly, we have recorded $6.8 million of capitalized costs for the PepperJack B#1 well to the Exploration expense line item of the consolidated statements of operations for the nine months ended September 30, 2018.

On September 21, 2018, we entered into an exploration agreement with a consortium of private exploration and production companies (the “Development Partners”) to further delineate and develop the PepperJack prospect. As part of the agreement, we assigned 75% of our working interest in the PepperJack A#1 well and acreage in the associated unit to the Development Partners and transferred our status as the operator of record. We received proceeds of $6.4 million for the assignment, which represented a reimbursement for 100% of the drilling costs and associated acreage, proceeds of $1.0 million for an option covering our minerals and leases in the PepperJack prospect area, and an overriding royalty interest in the PepperJack prospect area. The Development Partners will begin completion operations on the PepperJack A#1 well in the fourth quarter of 2018 and we will participate as a 25% non-operated working interest owner.

Business Environment

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

Commodity Prices

Oil and natural gas prices have been historically volatile based upon the dynamics of supply and demand. The U.S. Energy Information Administration ("EIA") forecasts that the WTI spot oil price will average $68.00 per Bbl in 2018 and $69.00 per Bbl in 2019 and that the Henry Hub spot natural gas prices will average $2.99 per MMBtu in 2018 and $3.12 per MMBtu in 2019.

To manage the variability in cash flows associated with the projected sale of our oil and natural gas production, we use various derivative instruments consisting of fixed-price swap contracts and costless collar contracts.

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

	2018			2017		
Benchmark Prices[1]	**Third Quarter**	**Second Quarter**	**First Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
WTI spot oil price ($/Bbl)	$ 73.16	$ 74.13	$ 64.87	$ 48.18	$ 46.02	$ 50.54
Henry Hub spot natural gas ($/MMBtu)	$ 3.01	$ 2.96	$ 2.81	$ 2.95	$ 2.98	$ 3.13

[1] Source: EIA

Rig Count

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:

	2018			2017		
U.S. Rotary Rig Count[1]	**Third Quarter**	**Second Quarter**	**First Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
Oil	863	858	797	750	756	662
Natural gas	189	187	194	189	184	160
Other	2	2	2	1	—	2
Total	1,054	1,047	993	940	940	824

[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, growing U.S. natural gas production is expected to support both increasing domestic consumption and higher natural gas exports. The EIA forecasts that natural gas inventories will reach almost 1.4 trillion cubic feet on March 31, 2019, which would be 17% lower than the previous five-year average.

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

	2018			2017		
Region[1]	**Third Quarter**	**Second Quarter**	**First Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
			(Bcf)			
East	763	460	229	861	564	268
Midwest	836	455	266	989	699	479
Mountain	177	139	87	220	187	142
Pacific	262	257	166	311	287	216
South Central	829	841	606	1,127	1,151	946
Total	2,867	2,152	1,354	3,508	2,888	2,051

[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 comprise our extensive asset base. We also regularly compare projected volumes to actual reported volumes and investigate unexpected variances.

Commodity Prices

Factors Affecting the Sales Price of Oil and Natural Gas

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

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

  The chemical composition of 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 receive the fixed ceiling price from the counterparty and we pay the market price. If the market price is below the fixed floor price, we receive the fixed floor price and we pay the market price. If the market price is between the fixed floor and fixed ceiling price, no payments are due from either party.

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, 2018 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.

Prior to amending and restating our credit agreement on November 1, 2017, we were allowed to hedge all of our estimated production from our proved developed producing reserves based on the most recent reserve information provided to our lenders. Pursuant to our Fourth Amended and Restated Credit Agreement, 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. Pursuant to our updated hedge provisions, we have hedged 79%, 70%, and 23% of our available oil and condensate hedge volumes for 2018, 2019, and 2020, respectively. Also, we have hedged 83% and 56% of our available natural gas hedge volumes for 2018 and 2019, 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, 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 generally accepted accounting principles in the United States ("U.S. GAAP") 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 U.S. 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, the most directly comparable U.S. GAAP financial measure, to Adjusted EBITDA and distributable cash flow for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)			
Net income	$ 60,775	$ 22,034	$ 131,422	$ 137,793
Adjustments to reconcile to Adjusted EBITDA:				
Depreciation, depletion, and amortization	29,273	29,204	88,135	84,483
Interest expense	5,518	4,172	15,319	11,660
Income tax expense	(2)	—	1,059	—
Accretion of asset retirement obligations	278	260	820	760
Equity–based compensation	9,596	7,675	24,947	18,614
Unrealized (gain) loss on commodity derivative instruments	8,718	14,320	47,733	(23,048)
Adjusted EBITDA	114,156	77,665	309,435	230,262
Adjustments to reconcile to distributable cash flow:				
Deferred revenue	(1)	(701)	1,300	(1,670)
Cash interest expense	(5,287)	(3,946)	(14,571)	(10,999)
(Gain) loss on sale of assets, net	—	—	(2)	(931)
Estimated replacement capital expenditures[1]	(2,750)	(3,250)	(8,750)	(10,250)
Cash paid to noncontrolling interests	(47)	(24)	(161)	(90)
Preferred unit distributions	(5,250)	(666)	(15,775)	(2,452)
Distributable cash flow	$ 100,821	$ 69,078	$ 271,476	$ 203,870

[1] On June 8, 2017, the Board approved a replacement capital expenditure estimate of $13.0 million for the period of April 1, 2017 to March 31, 2018. On April 27, 2018, the Board approved a replacement capital expenditure estimate of $11.0 million for the period of April 1, 2018 to March 31, 2019.

Results of Operations

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

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

	Three Months Ended September 30,			
	2018	2017	Variance	
	(Dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)	1,251	911	340	37.3 %
Natural gas (MMcf)[1]	19,153	14,974	4,179	27.9 %
Equivalents (MBoe)	4,443	3,407	1,036	30.4 %
Equivalents/day (MBoe)	48.3	37.0	11.3	30.5 %
Revenue:				
Oil and condensate sales	$ 82,712	$ 41,361	$ 41,351	100.0 %
Natural gas and natural gas liquids sales[1]	63,080	45,047	18,033	40.0 %
Lease bonus and other income	12,440	12,044	396	3.3 %
Revenue from contracts with customers	158,232	98,452	59,780	60.7 %
Gain (loss) on commodity derivative instruments	(18,514)	(9,341)	(9,173)	98.2 %
Total revenue	$ 139,718	$ 89,111	$ 50,607	56.8 %
Realized prices:				
Oil and condensate ($/Bbl)	$ 66.12	$ 45.39	$ 20.73	45.7 %
Natural gas ($/Mcf)[1]	3.29	3.01	0.28	9.3 %
Equivalents ($/Boe)	$ 32.81	$ 25.36	$ 7.45	29.4 %
Operating expenses:				
Lease operating expense	$ 4,229	$ 4,569	$ (340)	(7.4)%
Production costs and ad valorem taxes	17,641	11,549	6,092	52.7 %
Exploration expense	34	8	26	NM[2]
Depreciation, depletion, and amortization	29,273	29,204	69	0.2 %
General and administrative	22,083	17,305	4,778	27.6 %

[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.

[2] Not meaningful

Revenue

Total revenue for the quarter ended September 30, 2018 increased compared to the quarter ended September 30, 2017. The increase in total revenue from the corresponding prior period is primarily due to increased oil and condensate sales and natural gas and NGL sales as a result of increased production volumes and higher realized commodity prices. The overall increase in total revenue was partially offset by the increased loss on commodity derivative instruments.

Oil and condensate sales. Oil and condensate sales during the current quarter were higher than the third quarter of 2017 primarily due to increased production volumes and higher realized commodity prices. Our mineral and royalty interest oil and condensate volumes increased 58% in the third quarter of 2018 relative to the corresponding period in 2017, primarily driven by production increases in the Midland and Delaware Basins (the "Midland/Delaware"), the Bakken/Three Forks play and the Eagle Ford Shale play. Our mineral and royalty interest oil and condensate volumes accounted for 90% and 78% of total oil and condensate volumes for the quarters ended September 30, 2018 and 2017, respectively.

Natural gas and natural gas liquids sales. Natural gas and NGL sales during the current quarter were higher than the third quarter of 2017 primarily due to increased production volumes, largely in the Haynesville/Bossier play, as well as the Midland/Delaware and the Bakken/Three Forks play. Mineral and royalty interest production accounted for 60% and 51% of our natural gas volumes for the quarters ended September 30, 2018 and 2017, respectively. There was also an increase in commodity prices between the comparative periods.

Gain (loss) on commodity derivative instruments. During the third quarter of 2018, we recognized an increased loss from our commodity derivative instruments compared to the same period in 2017. 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.

Lease bonus and other income. When we lease our mineral interests, we generally receive an upfront cash payment, or a lease bonus. Lease bonus income 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 2018 was slightly higher than the same period of 2017. Leasing activity in the Austin Chalk, Bakken/Three Forks, Marmaton and Wilcox/Yegua trends made up the majority of lease bonus revenue in the third quarter of 2018.

Operating and Other Expenses

Lease operating expense. Lease operating expense decreased for the quarter ended September 30, 2018 as compared to the same period in 2017, primarily due to lower workover and other service-related expenses 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, 2018, production costs and ad valorem taxes increased as compared to the quarter ended September 30, 2017, generally as a result of increased oil and condensate and natural gas production volumes, as well as higher oil and condensate prices.

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 for the three months ended September 30, 2018 related to additional costs for the PepperJack B#1 well. Exploration expense for the quarter ended September 30, 2017 represented costs incurred to acquire 3-D seismic information related to our mineral and royalty interests from a third-party service provider.

Depreciation, depletion, and amortization. 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 was relatively flat for the quarter ended September 30, 2018 as compared to the same period in 2017, primarily due to the impact of higher production partially offset by lower depletion rates.

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, 2018, general and administrative expenses increased as compared to the same period in 2017, primarily due to higher costs associated with our incentive compensation plans period over period, partially offset by lower brokerage and legal fees associated with our acquisition activity.

Interest expense. Interest expense was higher in the third quarter of 2018 due to increased borrowings under our credit facility and higher interest rates. Average outstanding borrowings during the third quarter of 2018 were higher than the third quarter of 2017 primarily due to funding of acquisitions in 2018 compared to 2017.

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

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

	Nine Months Ended September 30,			
	2018	2017	Variance	
	(Dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)	3,623	2,597	1,026	39.5 %
Natural gas (MMcf)[1]	52,205	44,459	7,746	17.4 %
Equivalents (MBoe)	12,324	10,007	2,317	23.2 %
Equivalents/day (MBoe)	45.1	36.7	8.4	22.9 %
Revenue:				
Oil and condensate sales	$ 232,920	$ 119,097	$ 113,823	95.6 %
Natural gas and natural gas liquids sales[1]	170,179	142,651	27,528	19.3 %
Lease bonus and other income	28,616	37,082	(8,466)	(22.8)%
Revenue from contracts with customers	431,715	298,830	132,885	44.5 %
Gain (loss) on commodity derivative instruments	(68,194)	35,387	(103,581)	(292.7)%
Total revenue	$ 363,521	$ 334,217	$ 29,304	8.8 %
Realized prices:				
Oil and condensate ($/Bbl)	$ 64.29	$ 45.87	$ 18.42	40.2 %
Natural gas ($/Mcf)[1]	3.26	3.21	0.05	1.6 %
Equivalents ($/Boe)	$ 32.71	$ 26.16	$ 6.55	25.0 %
Operating expenses:				
Lease operating expense	$ 12,767	$ 12,906	$ (139)	(1.1)%
Production costs and ad valorem taxes	46,939	35,314	11,625	32.9 %
Exploration expense	6,782	616	6,166	NM[2]
Depreciation, depletion, and amortization	88,135	84,483	3,652	4.3 %
General and administrative	60,416	51,998	8,418	16.2 %

[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.

[2] Not meaningful

Revenue

Total revenues for the nine months ended September 30, 2018 increased compared to the nine months ended September 30, 2017. The increase in total revenue from the corresponding prior period is primarily due to increased oil and condensate sales and natural gas and NGL sales as a result of increased production volumes and higher realized commodity prices. The overall increase in total revenue was partially offset by a loss on commodity derivative instruments for the nine months ended September 30, 2018 compared to a gain in the same period of 2017.

Oil and condensate sales. Oil and condensate sales during the nine months ended September 30, 2018 were higher than the corresponding period in 2017 primarily due to increased production volumes and higher realized commodity prices. Our mineral and royalty interest oil and condensate volumes increased 54% for the nine months ended September 30, 2018 relative to the corresponding period in 2017, primarily driven by production increases in the Midland/Delaware, the Bakken/Three Forks play and the Eagle Ford Shale play. Our mineral and royalty interest oil and condensate volumes accounted for 90% and 81% of total oil and condensate volumes for the nine months ended September 30, 2018 and 2017, respectively.

Natural gas and natural gas liquids sales. Natural gas and NGL sales during the nine months ended September 30, 2018 were higher than the corresponding period in 2017 primarily due to increased production volumes, largely in the Haynesville/Bossier play, as well as the Midland/Delaware and the Bakken/Three Forks play. Mineral and royalty interest production accounted for 59% and 50% of our natural gas volumes for the nine months ended September 30, 2018 and 2017, respectively.

Gain (loss) on commodity derivative instruments. During the nine months ended September 30, 2018, we recognized a loss from our commodity derivative instruments compared to a gain in the same period of 2017. 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.

Lease bonus and other income. Lease bonus and other income was lower for the nine months ended September 30, 2018 as compared to the same period in 2017, though we successfully closed significant lease transactions in the Austin Chalk, Bakken/Three Forks, Canyon Lime, Douglas, Eagle Ford, Frio, Haynesville/Bossier, Wolfcamp and Woodford trends.

Operating and Other Expenses

Lease operating expense. Lease operating expense was relatively flat for the nine months ended September 30, 2018 as compared to the same period in 2017, primarily due to the absence of any significant remedial projects being performed by our operators on wells in which we own a non-operating working interest.

Production costs and ad valorem taxes. For the nine months ended September 30, 2018, production costs and ad valorem taxes increased from the comparative period in 2017, generally as a result of higher oil and condensate commodity prices, as well as increased oil and condensate and natural gas production volumes.

Exploration expense. Exploration expense for the nine months ended September 30, 2018 related to the PepperJack B#1 well. Exploration expense for the nine months ended September 30, 2017 consisted of costs incurred to acquire 3-D seismic information related to our mineral and royalty interests from a third-party service provider.

Depreciation, depletion, and amortization. Depreciation, depletion, and amortization increased for the nine months ended September 30, 2018 as compared to the same period in 2017 primarily due to higher production partially offset by lower depletion rates.

General and administrative. For the nine months ended September 30, 2018, general and administrative expenses increased as compared to the same period in 2017 due to increased costs attributable to our incentive compensation plans, partially offset by lower brokerage and legal fees associated with our acquisition activity.

Interest expense. Interest expense increased due to higher average outstanding borrowings under our credit facility and higher interest rates. Average outstanding borrowings during the first nine months ended September 30, 2018 were higher than the nine months ended September 30, 2017, primarily due to funding of acquisitions during the nine months ended September 30, 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 distributions equal in amount to no less than the applicable minimum quarterly distribution will be paid on each common and subordinated 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 and subordinated units quarterly or on any other basis, at the applicable minimum quarterly distribution rate or at any other rate, and there is no guarantee that we will pay distributions to our common and subordinated unitholders in any quarter. Our minimum quarterly distribution provides the common unitholders a specified priority right to distributions over the subordinated unitholders. 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. Like a number of other master limited partnerships, we are required by our partnership agreement to retain cash from our operations in an amount equal to our estimated replacement capital requirements. On April 27, 2018, the Board approved a replacement capital expenditure estimate of $11.0 million for the period of April 1, 2018 to March 31, 2019.

Cash Flows

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

	Nine Months Ended September 30,		
	2018	2017	Change
	(in thousands)		
Cash flows provided by operating activities	$ 289,719	$ 211,666	$ 78,053
Cash flows used in investing activities	(143,725)	(116,482)	(27,243)
Cash flows used in financing activities	(147,195)	(96,045)	(51,150)

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 higher commodity revenue driven by increased oil and natural gas production and higher realized commodity prices period over period, partially offset by the net cash paid on settlement of commodity derivative instruments for the nine months ended September 30, 2018 compared to cash received for the same period of 2017.

Investing Activities. Net cash used in investing activities increased in the first nine months of 2018 as compared to the corresponding period in 2017. The increase was primarily due to more cash spent on acquisitions and additions to oil and natural gas properties, partially offset by higher proceeds received from our farmout agreements.

Financing Activities. Cash flows used in financing activities for the nine months ended September 30, 2018 increased primarily due to increased distributions to common and subordinated unitholders, distributions to holders of Series B cumulative convertible preferred units, and increased repayments of borrowings under our credit facility, which was partially offset by increased proceeds from the issuance of our common units and decreased redemptions of Series A redeemable preferred units.

Development Capital Expenditures

Our 2018 total development capital expenditure budget is estimated at $45.0 million to $50.0 million, of which $45.7 million has been invested in the nine months ended September 30, 2018. The largest component of this budget relates to our working-interest participation program in certain Haynesville/Bossier wells in the Shelby Trough area of East Texas. In the first nine months of 2018, we spent $29.2 million in this program, net of farmout reimbursements, related to completions in wells which were spud prior to the farmouts. We do not expect to incur any additional capital expenditures in this program for the remainder of 2018, net of farmout reimbursements. In the PepperJack prospect area, we spent approximately $11.9 million during the nine months ended September 30, 2018 to drill and log two wells targeting the Lower Wilcox formation. We expect to incur an additional $0.5 million to $0.7 million related to the completion costs for the PepperJack A#1 well in the fourth quarter of 2018.

As a result of our legacy working-interest participation program, we regularly have minor miscellaneous capital expenditures related to workovers/recompletions, leases, and minor infrastructure projects. Given their nature, the amount and timing of capital to be invested in these types of projects is difficult to forecast; as such, we expect that we will invest approximately $1.0 million to $2.0 million on similar projects for the fourth quarter of 2018.

Acquisitions

We spent approximately $106.4 million and issued common units valued at $22.5 million during the nine months ended September 30, 2018 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 Acquisitions to our unaudited 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, 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. On November 1, 2017, we entered into the Fourth Amended and Restated Credit Agreement to extend the maturity date for a term of five years, create a swingline facility that permits short-term borrowings on same-day notice, and make other changes to the hedging and restrictive covenants. The borrowing base was reconfirmed at $550.0 million with our fall 2017 redetermination, was increased to $600.0 million effective May 4, 2018 with our spring 2018 redetermination, and was further increased to $675.0 million effective October 31, 2018 with our fall 2018 redetermination. Our credit facility terminates on November 1, 2022. As of September 30, 2018, we had outstanding borrowings of $402.0 million at a weighted-average interest rate of 4.75%.

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. Under the Fourth Amended and Restated Credit Agreement, we additionally have the right to request a redetermination following acquisition of oil and natural gas properties in excess of 10% of the value of the borrowing base immediately prior to such acquisition.

Outstanding borrowings under the credit agreement bear interest at a floating rate elected by us equal to an alternative base rate (which is equal to the greatest of the Prime Rate, the Federal Funds effective rate plus 0.50%, or 1-month LIBOR plus 1.00%) or LIBOR, in each case, plus the applicable margin. The applicable margin ranges from 1.00% to 2.00% in the case of the alternative base rate and from 2.00% to 3.00% in the case of LIBOR, depending on the borrowings outstanding in relation to the borrowing base. Effective October 31, 2018, the applicable margin for LIBOR was reduced to between 1.75% and 2.75% and the applicable margin for the alternative base rate was reduced to between 0.75% and 1.75%.

We 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 liens on substantially all of our producing properties.

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 due to a failure to satisfy one of the financial covenants) or during any time that our borrowing base is lower than the loans outstanding under the credit agreement. The lenders have the right to accelerate all of the indebtedness under the credit agreement upon the occurrence and during the continuance of any event of default, and the credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy, and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods. As of September 30, 2018, we were in compliance with all debt covenants.

Contractual Obligations

As of September 30, 2018, there have been no material changes to our contractual obligations previously disclosed in our 2017 Annual Report on Form 10-K.

Off-Balance Sheet Arrangements

As of September 30, 2018, we did not have any material off-balance sheet arrangements.

Critical Accounting Policies and Related Estimates

As of September 30, 2018, there have been no significant changes to our critical accounting policies and related estimates previously disclosed in our 2017 Annual Report on Form 10-K.

New and Revised Financial Accounting Standards

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

Our major market risk exposure is the pricing of oil, natural gas, and 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 volatile for several years, and we expect this unpredictability to continue in the future. The prices that our operators receive for production depend on many factors outside of our or their control. To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we use commodity derivative instruments to reduce our exposure to price volatility of oil and natural gas. The counterparties to the contracts are unrelated third parties. The contracts settle monthly in cash based on a designated floating price. The designated floating price is based on the NYMEX benchmark for oil and natural gas. We have not designated any of our contracts as fair value or cash flow hedges. Accordingly, the changes in fair value of the contracts are included in net income in the period of the change. See Note 5 – Commodity Derivative Financial Instruments and Note 6 – Fair Value Measurements to the unaudited 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, 2018 by 10%. This results in an approximate 2% reduction of proved reserve volumes as compared to the unadjusted September 30, 2018 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, 2018, we had ten counterparties, all of which were rated Baa1 or better by Moody's. As of September 30, 2018, nine of our counterparties are lenders under our credit facility.

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

Interest Rate Risk

We have exposure to changes in interest rates on our indebtedness. As of September 30, 2018, we had $402.0 million of outstanding borrowings under our credit facility, bearing interest at a weighted-average interest rate of 4.75%. 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 $3.0 million for the nine months ended September 30, 2018, assuming that our indebtedness remained constant throughout the period. We may use certain derivative instruments to hedge our exposure to variable interest rates in the future, but we do not currently have any interest rate hedges in place.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (the "Exchange Act"), we have evaluated, under the supervision and with the participation of management of our general partner, including our general partner's principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report on Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our general partner's principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our general partner's principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of September 30, 2018.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended September 30, 2018 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 2017 Annual Report on Form 10-K. There has been no material change in our risk factors from those described in our 2017 Annual Report on Form 10-K. These risks are not the only risks that we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may materially adversely affect our business, financial condition or results of operations.

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

Recent Sales of Unregistered Securities

During the three months ended September 30, 2018, we closed on purchases of certain mineral and royalty interests using an aggregate of 1,226,612 common units valued at $22.5 million to partially fund the purchases.

The issuance of the common units was made in reliance upon an exemption from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereunder.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

None.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit Number	Description
2.1**	Purchase and Sale Agreement, dated as of November 22, 2017, by and among Noble Energy Inc., Noble Energy Wyco, LLC, Noble Energy US Holdings, LLC, Rosetta Resources Operating LP, and Black Stone Minerals Company, L.P. (incorporated herein by reference to Exhibit 2.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on November 29, 2017 (SEC File No. 001-37362)).
3.1	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	XBRL Instance Document
*101.SCH	XBRL Schema Document
*101.CAL	XBRL Calculation Linkbase Document
*101.LAB	XBRL Label Linkbase Document
*101.PRE	XBRL Presentation Linkbase Document
*101.DEF	XBRL Definition Linkbase Document

* Filed or furnished herewith.

** Schedules and exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The Partnership agrees to furnish supplementally a copy of the omitted schedules and exhibits to the SEC upon request.

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 6, 2018	By:	/s/ Thomas L. Carter, Jr.
		Thomas L. Carter, Jr. Chief Executive Officer (Principal Executive Officer)
Date: November 6, 2018	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 6, 2018

/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 6, 2018

/s/ Jeffrey P. Wood

Jeffrey P. Wood
President and Chief Financial Officer
Black Stone Minerals GP, L.L.C.,
the general partner of Black Stone Minerals, L.P.

Exhibit 32.1

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

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

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

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

Date: November 6, 2018

/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 6, 2018

/s/ Jeffrey P. Wood

Jeffrey P. Wood
President and Chief Financial Officer
Black Stone Minerals GP, L.L.C.,
the general partner of Black Stone Minerals, L.P.