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, 2015

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting 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	☐

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

As of November 6, 2015, there were 96,185,592 common limited partner units, 95,057,312 subordinated limited partner units, and 117,963 preferred units of the registrant outstanding.

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PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

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

	September 30, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 5,570	$ 14,803
Accounts receivable	52,347	74,092
Commodity derivative assets	34,336	37,471
Prepaid expenses and other current assets	1,404	8,538
TOTAL CURRENT ASSETS	93,657	134,904
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, at cost, on the basis of the successful efforts method of accounting, includes unproved properties of $621,140 and $626,376 at September 30, 2015 and December 31, 2014, respectively	2,481,864	2,379,543
Accumulated depreciation, depletion and amortization, including impairment	(1,430,004)	(1,191,861)
Oil and natural gas properties, net	1,051,860	1,187,682
Other property and equipment, net of accumulated depreciation of $14,687 and $12,994 at September 30, 2015 and December 31, 2014, respectively	67	1,664
NET PROPERTY AND EQUIPMENT	1,051,927	1,189,346
DEFERRED CHARGES AND OTHER LONG-TERM ASSETS	15,862	2,532
TOTAL ASSETS	$ 1,161,446	$ 1,326,782
LIABILITIES, MEZZANINE EQUITY AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 28,108	$ 29,415
Accrued liabilities	18,227	16,252
Accrued distribution payable to Predecessor unitholders	—	52,905
TOTAL CURRENT LIABILITIES	46,335	98,572
LONG-TERM LIABILITIES		
Credit facility	43,000	394,000
Accrued incentive compensation	8,401	6,530
Deferred revenue	3,333	3,917
Asset retirement obligations	10,181	9,381
TOTAL LIABILITIES	111,250	512,400
COMMITMENTS AND CONTINGENCIES (Note 7)		
MEZZANINE EQUITY		
Partners' equity - redeemable preferred units, 118 and 157 units outstanding at September 30, 2015 and December 31, 2014, respectively	120,936	161,165
EQUITY		
Predecessor equity - common limited partner units, no units and 164,484 outstanding at September 30, 2015 and December 31, 2014, respectively	—	653,217
Partners' equity - general partner units	—	—
Partners' equity - common limited partner units, 96,186 and no units outstanding at September 30, 2015 and December 31, 2014, respectively	621,796	—
Partners' equity - subordinated limited partner units, 95,057 and no units outstanding at September 30, 2015 and December 31, 2014, respectively	305,156	—
Noncontrolling interests	2,308	—
TOTAL EQUITY	929,260	653,217
TOTAL LIABILITIES, MEZZANINE EQUITY AND EQUITY	$ 1,161,446	$ 1,326,782

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

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

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
REVENUE				
Oil and condensate sales	$ 44,128	$ 71,089	$ 126,584	$ 195,665
Natural gas and natural gas liquids sales	32,191	45,914	92,799	156,554
Gain on commodity derivative instruments	56,430	8,682	57,450	339
Lease bonus and other income	4,271	7,110	16,051	26,586
TOTAL REVENUE	137,020	132,795	292,884	379,144
OPERATING (INCOME) EXPENSE				
Lease operating expense	4,924	6,037	16,540	15,707
Production costs and ad valorem taxes	8,175	12,181	26,250	33,589
Exploration expense	1,817	440	2,014	444
Depreciation, depletion and amortization	23,288	37,065	83,414	84,058
Impairment of oil and natural gas properties	24,854	—	156,683	—
General and administrative	18,994	15,644	53,530	45,607
Accretion of asset retirement obligations	265	148	805	443
(Gain) loss on sale of assets, net	4	—	(20)	—
TOTAL OPERATING EXPENSE	82,321	71,515	339,216	179,848
INCOME (LOSS) FROM OPERATIONS	54,699	61,280	(46,332)	199,296
OTHER INCOME (EXPENSE)				
Interest and investment income	18	3	46	27
Interest expense	(870)	(3,440)	(5,530)	(10,292)
Other income	45	62	241	869
TOTAL OTHER EXPENSE	(807)	(3,375)	(5,243)	(9,396)
NET INCOME (LOSS)	53,892	57,905	(51,575)	189,900
NET INCOME ATTRIBUTABLE TO PREDECESSOR	—	(57,905)	(450)	(189,900)
NET (INCOME) LOSS ATTRIBUTABLE TO NONCONTROLLING INTERESTS SUBSEQUENT TO INITIAL PUBLIC OFFERING	(3)	—	137	—
DISTRIBUTIONS ON PREFERRED UNITS SUBSEQUENT TO INITIAL PUBLIC OFFERING	(2,973)	—	(4,783)	—
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND LIMITED PARTNERS SUBSEQUENT TO INITIAL PUBLIC OFFERING	$ 50,916	$ —	$ (56,671)	$ —
ALLOCATION OF NET INCOME (LOSS) SUBSEQUENT TO INITIAL PUBLIC OFFERING ATTRIBUTABLE TO:				
General partner interest	$ —		$ —	
Common limited partner interests	25,608		(28,502)	
Subordinated limited partner interests	25,308		(28,169)	
	$ 50,916		$ (56,671)	
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER UNIT:				
Per common limited partner unit (basic and diluted)	$ 0.27		$ (0.30)	
Weighted average common limited partner units outstanding (basic and diluted)	96,186		96,183	
Per subordinated limited partner unit (basic and diluted)	$ 0.27		$ (0.30)	
Weighted average subordinated limited partner units outstanding (basic and diluted)	95,057		95,057	
DISTRIBUTIONS DECLARED AND PAID SUBSEQUENT TO INITIAL PUBLIC OFFERING:				
Per common limited partner unit	$ 0.1615		$ 0.1615	
Per subordinated limited partner unit	$ 0.1615		$ 0.1615	

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

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

	Predecessor		Black Stone Minerals, L.P.					
	Common units	Total equity	Common units	Subordinated units	Partners' equity—common units	Partners' equity—subordinated units	Noncontrolling interests	Total equity
BALANCE AT DECEMBER 31, 2014	164,484	$ 653,217	—	—	$ —	$ —	$ —	$ 653,217
Conversion of Predecessor redeemable preferred units	2,750	39,240	—	—	—	—	—	39,240
Restricted Predecessor units granted	562	—	—	—	—	—	—	—
Repurchases of Predecessor units	(164)	(3,015)	—	—	—	—	—	(3,015)
Distributions to Predecessor unitholders and noncontrolling interests	—	(73,205)	—	—	—	—	—	(73,205)
Distributions on Predecessor preferred units	—	(4,040)	—	—	—	—	—	(4,040)
Net income attributable to Predecessor	—	450	—	—	—	—	—	450
Allocation of Predecessor units and equity	(167,632)	(612,647)	72,575	95,057	264,235	345,875	2,537	—
Issuance of common units for initial public offering, net of offering costs	—	—	22,500	—	391,500	—	—	391,500
Restricted common units granted	—	—	1,111	—	—	—	—	—
Equity-based compensation	—	—	—	—	10,250	2,802	—	13,052
Distributions	—	—	—	—	(15,534)	(15,352)	(92)	(30,978)
Charges to Partners' equity for accrued distribution equivalent rights	—	—	—	—	(153)	—	—	(153)
Net loss subsequent to initial public offering	—	—	—	—	(26,096)	(25,792)	(137)	(52,025)
Distributions on preferred units	—	—	—	—	(2,406)	(2,377)	—	(4,783)
BALANCE AT SEPTEMBER 30, 2015	—	$ —	96,186	95,057	$ 621,796	$ 305,156	$ 2,308	$ 929,260

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

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

	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income (loss)	$ (51,575)	$ 189,900
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, and amortization	83,414	84,058
Impairment of oil and natural gas properties	156,683	—
Accretion of asset retirement obligations	805	443
Amortization of deferred charges	724	726
Gain on commodity derivative instruments	(57,450)	(339)
Net cash received (paid) on settlement of commodity derivative instruments	46,532	(3,369)
Equity-based compensation	13,052	7,452
Gain on sale of assets, net	(20)	—
Changes in operating assets and liabilities:		
Accounts receivable	22,485	(133)
Prepaid expenses and other current assets	(453)	(4,178)
Accounts payable and accrued liabilities	3,674	6,373
Deferred revenue	(584)	(2,516)
Settlement of asset retirement obligations	(122)	(19)
NET CASH PROVIDED BY OPERATING ACTIVITIES	217,165	278,398
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to oil and natural gas properties	(42,401)	(57,427)
Purchase of other property and equipment	(96)	(312)
Proceeds from the sale of oil and natural gas properties	432	10,625
Acquisitions of oil and natural gas properties	(62,157)	(45,431)
NET CASH USED IN INVESTING ACTIVITIES	(104,222)	(92,545)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from issuance of common units of Black Stone Minerals, L.P., net of offering costs	399,087	—
Distributions to Predecessor unitholders	(126,383)	(170,117)
Distributions to Black Stone Minerals, L.P. common and subordinated unitholders	(30,886)	—
Distributions to preferred unitholders	(9,812)	(11,769)
Distributions to noncontrolling interests	(167)	—
Repurchases of Predecessor units	(3,015)	(5,199)
Net repayments under senior line of credit	(351,000)	(21,000)
Note receivable-officers	—	101
NET CASH USED IN FINANCING ACTIVITIES	(122,176)	(207,984)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(9,233)	(22,131)
CASH AND CASH EQUIVALENTS - beginning of the period	14,803	30,123
CASH AND CASH EQUIVALENTS - end of the period	$ 5,570	$ 7,992
SUPPLEMENTAL DISCLOSURE		
Interest paid	$ 4,794	$ 9,721
NON-CASH ACTIVITIES		
Accrued Predecessor distributions payable	$ (53,248)	$ (1,155)
Conversion of redeemable preferred units	$ (39,240)	$ (221)
Accrued distributions payable for preferred units	$ (989)	$ (6)
Property additions and acquisitions financed through accounts payable and accrued liabilities	$ 12,844	$ 22,086
Public offering costs capitalized and offset against proceeds from initial public offering	$ 7,587	$ —
Accrued distribution equivalent rights	$ 153	$ —
Asset retirement obligations incurred	$ 117	$ 99
Liabilities assumed as consideration for oil and natural gas properties acquired	$ —	$ 7,000
Acquisition of oil and natural gas properties financed through issuance of common units	$ —	$ 2,258
Deferred revenue settled through acquisition of oil and natural gas properties	$ —	$ (2,657)

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

NOTE 1—BUSINESS AND BASIS OF PRESENTATION

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

Black Stone Minerals Company, L.P., a Delaware limited partnership, and its subsidiaries (collectively referred to as "BSMC" or the "Predecessor") own oil and natural gas mineral interests in the United States. In connection with the IPO, BSMC was merged into a wholly owned subsidiary of BSM, with BSMC as the surviving entity. Pursuant to the merger, the Class A and Class B common units representing limited partner interests of the Predecessor were converted into an aggregate of 72,574,715 common units and 95,057,312 subordinated units of BSM at a conversion ratio of 12.9465:1 for 0.4329 common units and 0.5671 subordinated units, and the preferred units of BSMC were converted into an aggregate of 117,963 preferred units of BSM at a conversion ratio of one to one. The merger is 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 "Company" 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, the Company's assets include nonparticipating and overriding royalty interests. These non-cost-bearing interests are collectively referred to as "mineral and royalty interests." As of September 30, 2015, the Company's mineral and royalty interests are located in most of the major onshore oil and natural gas producing basins spread across 41 states and 62 onshore oil and natural gas producing basins of the continental U.S. The Company 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 Company have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States and pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). These unaudited interim consolidated financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with U.S. GAAP. Accordingly, the accompanying unaudited interim consolidated financial statements and related notes should be read in conjunction with the Company's annual consolidated financial statements and related notes included in its final prospectus (the "Prospectus") dated April 30, 2015 and filed with the SEC, pursuant to Rule 424(b) under the Securities Act of 1933 (the "Securities Act"), on May 1, 2015. The financial statements include the consolidated results of the Company. BSM's general partner, Black Stone Minerals GP, L.L.C., is a wholly owned subsidiary. 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 Company. In the opinion of management, all material adjustments, which are of a normal and recurring nature, necessary for a fair presentation of the results for the periods presented have been reflected. The results of operations for the three and nine months ended September 30, 2015 are not necessarily indicative of the results to be expected for the full year.

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

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

Segment reporting: The Company 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 Company'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: Our significant accounting policies are disclosed in Note 2 of the consolidated financial statements for the years ended December 31, 2014 and 2013 included in the Prospectus. There have been no changes in such policies or the application of such policies during the nine months ended September 30, 2015.

New accounting pronouncements: In May 2014, the Financial Accounting Standards Board (the "FASB") issued an accounting standards update on a comprehensive new revenue recognition standard that will supersede Accounting Standards Codification ("ASC") 605, *Revenue Recognition*. The new accounting guidance creates a framework under which an entity will allocate the transaction price to separate performance obligations and recognize revenue when each performance obligation is satisfied. Under the new standard, entities will be required to use judgment and make estimates, including identifying performance obligations in a contract, estimating the amount of variable consideration to include in the transaction price, allocating the transaction price to each separate performance obligation, and determining when an entity satisfies its performance obligations. The standard allows for either "full retrospective" adoption, meaning that the standard is applied to all of the periods presented with a cumulative catch-up as of the earliest period presented, or "modified retrospective" adoption, meaning the standard is applied only to the most current period presented in the financial statements with a cumulative catch-up as of the current period. In July 2015, the FASB decided to defer the original effective date by one year to be effective for annual reporting periods beginning after December 15, 2017 instead of December 15, 2016 for public entities. The Company is still evaluating the impact that the new accounting guidance will have on its consolidated financial statements and related disclosures and has not yet determined the method by which it will adopt the standard.

In April 2015, the FASB issued an accounting standards update that requires debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying value of that debt liability, consistent with debt discounts. The guidance is effective retrospectively for fiscal years, and interim periods within those years, beginning after December 15, 2015. Early adoption is permitted for financial statements that have not been previously issued. The Company does not expect the impact of adopting this guidance will be material to the Company's consolidated financial statements and related disclosures.

In April 2015, the FASB issued an accounting standards update that specifies that for purposes of calculating historical earnings per unit under the two-class method, the earnings (losses) of a transferred business before the date of a dropdown transaction should be allocated entirely to the general partner. In that circumstance, the previously reported earnings per unit of the limited partners (which is typically the earnings per unit measure presented in the financial statements) would not change as a result of the dropdown transaction. Qualitative disclosures about how the rights to the earnings (losses) differ before and after the dropdown transaction occurs for purposes of computing earnings per unit under the two-class method also are required. The guidance is effective retrospectively for fiscal years, and interim periods within those years, beginning after December 15, 2015. Early adoption is permitted. The Company does not expect the impact of adopting this guidance will be material to the Company's consolidated financial statements and related disclosures.

In September 2015, the FASB issued an accounting standards update that requires that adjustments to provisional amounts identified during the measurement period of a business combination be recognized in the reporting period in which those adjustments are determined, including the effect on earnings, if any, calculated as if the accounting had been completed at the acquisition date. This eliminates the previous requirement to retrospectively account for such adjustments. The new standard also requires additional disclosures related to the income statement effects of adjustments to provisional amounts identified during the measurement period. The guidance is effective for public companies during interim and annual reporting periods beginning after December 15, 2015. Early adoption is permitted. The Company does not expect the impact of adopting this guidance will be material to the Company's consolidated financial statements and related disclosures.

NOTE 3—ASSET RETIREMENT OBLIGATIONS

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

	For the nine months ended September 30, 2015
	(In thousands)
Beginning asset retirement obligations	$ 9,381
Liabilities incurred	117
Liabilities settled	(122)
Accretion expense	805
Ending asset retirement obligations	$ 10,181

NOTE 4—DERIVATIVES AND FINANCIAL INSTRUMENTS

The Company's ongoing operations expose it to changes in the market price for oil and natural gas. To mitigate these price fluctuations, the Company uses commodity derivative instruments. From time to time, such instruments may include fixed-price swaps, costless collars, fixed-price contracts, and other contractual arrangements. The Company does not enter into derivative instruments for speculative purposes.

A fixed-price-swap contract between the Company and the counterparty specifies a fixed commodity price and a future settlement date. The Company will receive from, or pay to, the counterparty the difference between the fixed swap price and the market price on the settlement date. Costless collars are a combination of a purchased put option and a sold call option, in which the premiums net to zero. With a costless collar, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the exercise price of the purchased put. The Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the exercise price for the sold call of the collar. The settlement paid or received is the difference between the market price on the settlement date and the related exercise price. All derivative instruments that have not yet been settled in cash are reflected as either derivative assets or liabilities in the Company's accompanying consolidated balance sheets as of September 30, 2015 and December 31, 2014. See Note 5 – Fair Value Measurement for further discussion.

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

	As of September 30, 2015			
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	$ 34,336	$ —	$ 34,336
Long-term asset	Deferred charges and other long-term assets	14,053	—	14,053
Total assets		$ 48,389	$ —	$ 48,389
Liabilities:				
Current liability	Commodity derivative liabilities	$ —	$ —	$ —
Long-term liability	Commodity derivative liabilities	—	—	—
Total liabilities		$ —	$ —	$ —

		As of December 31, 2014		
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	$ 37,656	$ (185)	$ 37,471
Long-term asset	Deferred charges and other long-term assets	—	—	—
Total assets		$ 37,656	$ (185)	$ 37,471
Liabilities:				
Current liability	Commodity derivative liabilities	$ 185	$ (185)	$ —
Long-term liability	Commodity derivative liabilities	—	—	—
Total liabilities		$ 185	$ (185)	$ —

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

	For the nine months ended September 30,	
Derivatives not designated as hedging instruments under ASC 815	**2015**	**2014**
	(In thousands)	
Beginning fair value of commodity derivative instruments	$ 37,471	$ (1,812)
Gain on oil derivative instruments	37,305	833
Gain (loss) on natural gas derivative instruments	20,145	(494)
Net cash (received) paid on settlements of oil derivative instruments	(32,274)	932
Net cash (received) paid on settlements of natural gas derivative instruments	(14,258)	2,437
Net change in fair value of commodity derivative instruments	10,918	3,708
Ending fair value of commodity derivative instruments	$ 48,389	$ 1,896

The Company had the following open derivative contracts for oil as of September 30, 2015:

Period and Type of Contract	Volume (Bbl)	Weighted Average (Per Bbl)	Range (Per Bbl) Low	High
Oil Collars:				
Q3 2015				
Collar contracts:				
Call Options	42,000	$ 102.48	$ 102.00	$ 103.55
Put Options	42,000	$ 84.76	$ 84.00	$ 85.00
Q4 2015				
Collar contracts:				
Call Options	30,000	$ 102.00	$ 102.00	$ 102.00
Put Options	30,000	$ 85.00	$ 85.00	$ 85.00
Oil Swaps:				
Q3 2015				
Swap contracts:	156,000	$ 57.89	$ 46.86	$ 60.22
Q4 2015				
Swap contracts:	531,000	$ 59.19	$ 47.39	$ 61.71
2016				
Swap contracts:	1,779,000	$ 57.63	$ 48.54	$ 63.07
2017				
Swap contracts:	703,000	$ 58.50	$ 52.73	$ 63.65

The Company had the following open derivative contracts for natural gas as of September 30, 2015:

Period and Type of Contract	Volume (MMBtu)	Weighted Average (Per MMBtu)	Range (Per MMBtu) Low	High
Natural Gas Swaps:				
Q4 2015				
Swap contracts:	7,600,000	$ 3.22	$ 2.82	$ 3.53
2016				
Swap contracts:	24,250,000	$ 3.18	$ 3.00	$ 3.41
2017				
Swap contracts:	9,650,000	$ 3.33	$ 3.14	$ 3.52

As of November 6, 2015, the Company has not entered into any additional derivative contracts for oil and natural gas.

NOTE 5—FAIR VALUE MEASUREMENT

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

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

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

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

Level 3—Inputs that are unobservable and significant to the fair value measurement (including the Company'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 Company'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, 2015 or the year ended December 31, 2014.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The Company 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 4 – Derivatives and Financial Instruments for further discussion.

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

	Fair Value Measurements Using			Effect of Counterparty	
	Level 1	Level 2	Level 3	Netting	Total
			(In thousands)		
As of September 30, 2015					
Financial Assets					
Commodity derivative instruments	$ —	$ 48,389	$ —	$ —	$ 48,389
Financial Liabilities					
Commodity derivative instruments	—	—	—	—	$ —
As of December 31, 2014					
Financial Assets					
Commodity derivative instruments	$ —	$ 37,656	$ —	$ (185)	$ 37,471
Financial Liabilities					
Commodity derivative instruments	—	185	—	(185)	$ —

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

The determination of the fair values of proved and unproved properties acquired in purchase transactions are prepared by estimating discounted-cash-flow projections. The factors used to determine fair value include estimates of economic reserves, future operating and development costs, future commodity prices, and a market-based weighted-average cost of capital.

Oil and natural gas properties are measured at fair value on a nonrecurring basis using the income approach when measuring 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. Significant Level 3 assumptions used to determine fair value include estimates of proved reserves, future commodity prices, the timing and amount of future production and capital expenditures, and a discount rate commensurate with the risk associated with the respective oil and natural gas properties.

The Company'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, 2015 or December 31, 2014.

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

	Fair Value Measurements Using			Net Book	
	Level 1	Level 2	Level 3	Value	Impairment
			(In thousands)		
As of September 30, 2015					
Impaired oil and natural gas properties	$ —	$ —	$ 127,630	$ 284,313	$ 156,683
As of December 31, 2014					
Impaired oil and natural gas properties	$ —	$ —	$ 81,864	$ 199,794	$ 117,930

The estimated carrying value of all debt as of September 30, 2015 and December 31, 2014 approximated the fair value due to variable market rates of interest. These fair values, which are Level 3 measurements, were estimated based on the Company's incremental borrowing rates for similar types of borrowing arrangements, when quoted market prices were not available. The estimated fair values of the Company's financial instruments are not necessarily indicative of the amounts that would be realized in a current market exchange. The carrying value of receivables and payables approximate fair value due to the short-term nature of the instruments.

NOTE 6—RELATED PARTY TRANSACTIONS

The Predecessor executed promissory notes dated April 15, 2010, in the amount of $0.5 million to certain officers of the Predecessor. The promissory notes related to the acquisition of a partnership interest in a former affiliate by the officers, and the notes were collateralized by a security interest in the Predecessor. The aggregate outstanding note balance and interest receivable of $0.1 million was received during the nine months ended September 30, 2014.

NOTE 7—COMMITMENTS AND CONTINGENCIES

Environmental Matters

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

Litigation

From time to time, the Company is involved in legal actions and claims arising in the ordinary course of business. The Company believes existing claims as of September 30, 2015 will be resolved without material adverse effect on the Company's financial condition or operations.

NOTE 8—CREDIT FACILITY

On January 23, 2015, the Company amended and restated its senior secured revolving credit agreement (the "Senior Line of Credit"). The Senior Line of Credit has a maximum credit amount of $1.0 billion. On October 28, 2015, the Senior Line of Credit was further amended to extend the term of the agreement from February 3, 2017 to February 4, 2019. The amount of the borrowing base is derived from the value of the Company's oil and natural gas properties determined by the lender syndicate using pricing assumptions that often differ from strip prices. The borrowing base was $700.0 million at December 31, 2014. The Company's semi-annual borrowing base redetermination process resulted in a decrease of the borrowing base to $600.0 million, effective April 10, 2015. Effective October 28, 2015, the borrowing base was further decreased to $550.0 million. Drawings on the Senior Line of Credit are used for the acquisition of oil and natural gas properties and for other general business purposes.

Borrowings under the Senior Line of Credit bear interest at LIBOR plus a margin between 1.50% and 2.50%, or prime rate plus a margin between 0.50% and 1.50%, with the margin depending on the borrowing base utilization percentage of the loan, as detailed in the table below. The prime rate is determined to be the higher of the financial institution's prime rate or the federal funds effective rate plus 0.50% per annum. The weighted-average interest rate of the Senior Line of Credit was 1.94% and 2.41% as of September 30, 2015 and December 31, 2014, respectively. Accrued interest is payable at the end of each calendar quarter or at the end of each interest period, unless the interest period is longer than 90 days in which case interest is payable at the end of every 90-day period. In addition, a commitment fee is payable at the end of each calendar quarter based on either a rate of 0.375% if the borrowing base utilization percentage is less than 50%, or 0.500% per annum if the borrowing base utilization percentage is equal to or greater than 50%. The Senior Line of Credit is secured by a majority of the Company's oil and natural gas production and assets.

	Borrowing Base Utilization				
Borrowing type	**<25%**	**≥25% <50%**	**≥50% <75%**	**≥75% <90%**	**≥90%**
Eurodollar Margin	1.50%	1.75%	2.00%	2.25%	2.50%
Base Rate Margin	0.50%	0.75%	1.00%	1.25%	1.50%

The Senior Line of Credit contains various limitations on future borrowings, leases, hedging, and sales of assets. Additionally, the Senior Line of Credit requires the Company 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, 2015, the Company was in compliance with all financial covenants in the Senior Line of Credit.

The aggregate principal balance outstanding was $43.0 million and $394.0 million at September 30, 2015 and December 31, 2014, respectively. The unused portion of the available borrowings under the Senior Line of Credit was $557.0 million and $306.0 million at September 30, 2015 and December 31, 2014, respectively. Refer to Note 1 – Business and Basis of Presentation for a discussion of the use of proceeds from the IPO.

NOTE 9—INCENTIVE COMPENSATION

Effective May 6, 2015, the Company's general partner adopted a long-term incentive plan (the "2015 LTIP"), pursuant to which non-employee directors of the Company's general partner and certain employees and consultants of the Company and its affiliates are eligible to receive awards with respect to the Company's common or subordinated units. In connection with the IPO, outstanding restricted common units in the Predecessor were exchanged for restricted common and subordinated units in the Company under the 2015 LTIP. Additionally, a provision contained in certain of the Predecessor's restricted unit agreements that allowed award recipients to request cash settlement for up to 50% of their restricted unit awards granted prior to December 31, 2014 was removed; as such, these awards are no longer classified as liability awards. The Company's general partner currently intends to grant new equity-based awards under the 2015 LTIP only with respect to common units. The 2015 LTIP permits the grant of unit options, unit appreciation rights, restricted units, unit awards, phantom units, distribution equivalent rights either in tandem with an award or as a separate award, cash awards, and other unit-based awards.

On May 6, 2015, in conjunction with the adoption of the 2015 LTIP, the Board of Directors of the Company's general partner (the "Board") approved a grant of awards to each of the Company's executive officers, certain other employees, and each of the non-employee directors of the Company's general partner. These awards consisted of restricted common units, restricted performance units (in the form of phantom units) with distribution equivalent rights, fully vested common units, and cash awards. The grants included 1,034,013 restricted common units subject to limitations on transferability, customary forfeiture provisions, and service-based graded vesting requirements through April 1, 2019. The holders of restricted common unit awards have all of the rights of a common unitholder, including non-forfeitable distribution rights with respect to their restricted common units. The grant-date fair value of these awards, net of estimated forfeitures, is recognized ratably using the straight-line attribution method. The Board also approved a grant of 947,142 restricted performance units that are subject to both performance-based and service-based vesting provisions. The number of common units issued to a recipient upon vesting of a restricted performance unit will be calculated based on performance against certain metrics that relate to the Company's performance over each of the four 12-month performance periods commencing April 1, 2015. The target number of common units subject to each restricted performance unit is one; however, based on the achievement of performance criteria, the number of common units that may be received in settlement of each restricted performance unit can range from zero to two times the target number. The restricted performance units are eligible to become earned as follows: 16.66%, 16.67%, and 16.67% of the performance units may become earned in each of the 12-month performance periods that end on March 31, 2016, March 31, 2017, and March 31, 2018, respectively. The remaining 50% of the restricted performance units are eligible to become earned during the final 12-month performance period that ends on March 31, 2019. If the performance criteria are not met for the final performance period, the awards allow for a make-up period ending on March 31, 2020. Compensation expense related to the restricted performance unit awards is determined by multiplying the number of common units underlying such awards that, based on the Company's estimate, are likely to vest, by the grant-date fair value and recognized using the accelerated attribution method. Distribution equivalent rights for the restricted performance unit awards that are expected to vest are charged to partners' capital. Additionally, non-employee directors of the Company's general partner received a one-time grant totaling 63,156 fully vested common units. Cash awards totaling $2.7 million with service-based graded vesting requirements through March 31, 2019 were also granted to certain other employees.

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, 2015 and 2014, respectively.

Incentive compensation expense	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	(In thousands)			
Cash—long-term incentive plan	$ 3,434	$ 4,457	$ 10,914	$ 10,182
Equity-based compensation—restricted common and subordinated units	3,136	1,716	7,086	5,148
Equity-based compensation—restricted performance units	2,070	—	3,330	—
Board of Directors incentive plan	484	550	2,636	3,710
Total incentive compensation expense	$ 9,124	$ 6,723	$ 23,966	$ 19,040

NOTE 10—REDEEMABLE PREFERRED UNITS

The Company has 117,963 and 157,203 preferred units outstanding with a carrying value of $120.9 million and $161.2 million as of September 30, 2015 and December 31, 2014, respectively. The aforementioned amounts include accrued distributions of $3.0 million and $4.0 million as of September 30, 2015 and December 31, 2014, respectively. The redeemable preferred units are classified as mezzanine equity on the consolidated balance sheets since redemption is outside the control of the Company. The preferred units are entitled to an annual distribution of 10% of the funded capital of the preferred units, payable on a quarterly basis in arrears.

The preferred units are convertible into common and subordinated units at any time at the option of the preferred unitholders. The preferred units have an adjusted conversion price of $14.2683 and an adjusted conversion rate of 30.3431 common units and 39.7427 subordinated units per preferred unit, which reflects the reverse split described in Note 1 – Business and Basis of Presentation and the capital restructuring related to the IPO. The owners of the preferred units could elect to have the Company redeem up to 25% per year of their initial balance of preferred units at face value, plus any accrued and unpaid distributions, on December 31 of each year from 2014 to 2017. The Company shall have the right, at its sole option, to redeem an amount of preferred units equal to the units being redeemed by an owner of preferred units on each December 31. Any amount of a given year's 25% of preferred units not redeemed on December 31 shall automatically convert to common and subordinated units on January 1 of the following year. For the nine months ended September 30, 2015, 39,240 preferred units totaling $39.2 million were converted into the equivalent of 1,190,664 common units and 1,559,502 subordinated units on an adjusted basis, which included units automatically converted on January 1, 2015.

NOTE 11—EARNINGS PER UNIT

The Company applies the two-class method for purposes of calculating earnings per unit ("EPU"). The holders of the Company'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 Company is allocated to our general partner and the common and subordinated unitholders in proportion to their pro rata ownership after giving effect to distributions, if any, declared during the period. The redeemable preferred units could be converted into 3.6 million common units and 4.7 million subordinated units as of September 30, 2015, and 4.8 million common units and 6.2 million subordinated units, on an adjusted basis, as of September 30, 2014. At September 30, 2015 and 2014, if the redeemable preferred units were converted to common and subordinated units, the effect would be anti-dilutive. Therefore, the redeemable preferred units are not included in the diluted EPU calculation. The Company's restricted performance unit awards are contingently issuable units that are considered in the calculation of diluted EPU. The Company 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. As of September 30, 2015, there were no units related to the Company'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,	
	2015	2014	2015	2014
	(In thousands, except per unit amounts)			
Net income (loss)	$ 53,892	$ 57,905	$ (51,575)	$ 189,900
Net income attributable to Predecessor	—	(57,905)	(450)	(189,900)
Net (income) loss attributable to noncontrolling interests subsequent to initial public offering	(3)	—	137	—
Distributions on preferred units subsequent to initial public offering	(2,973)	—	(4,783)	—
Net income (loss) attributable to the general partner and limited partners subsequent to initial public offering	$ 50,916	$ —	$ (56,671)	$ —
Allocation of net income (loss) subsequent to initial public offering attributable to:				
General partner interest	$ —		$ —	
Common limited partner interests	25,608		(28,502)	
Subordinated limited partner interests	25,308		(28,169)	
	$ 50,916		$ (56,671)	
Net income (loss) attributable to limited partners per unit:				
Per common limited partner unit (basic and diluted)	$ 0.27		$ (0.30)	
Weighted average common limited partner units outstanding (basic and diluted)	96,186		96,183	
Per subordinated limited partner unit (basic and diluted)	$ 0.27		$ (0.30)	
Weighted average subordinated limited partner units outstanding (basic and diluted)	95,057		95,057	

NOTE 12—SUBSEQUENT EVENTS

On October 20, 2015, the Company announced its intention to commence a cash tender offer to purchase up to 100% of the 117,963 outstanding preferred units from its preferred unitholders at the units' par value of $1,000.00 per preferred unit, plus unpaid accrued yield. The Company intends to fund the tender offer with cash on hand and funds available under its revolving credit facility. BSM commenced the proposed tender offer on November 6, 2015. The proposed tender offer will expire on December 10, 2015.

On October 28, 2015, the Company received a cash payment of $18.7 million from an operator to terminate an exploration and development agreement related to certain mineral and leasehold interests owned by the Company.

On November 9, 2015, the Board approved a distribution for the period July 1, 2015 through September 30, 2015 of $0.2625 per unit for common and subordinated unitholders. Distributions will be payable on November 27, 2015 to unitholders of record at the close of business on November 19, 2015.

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

You should read the following discussion and analysis of our financial condition and results of operations in conjunction with our unaudited consolidated financial statements and notes thereto presented in this Quarterly Report on Form 10-Q, as well as the historical consolidated financial statements of our accounting predecessor for financial reporting purposes, Black Stone Minerals Company, L.P., included in our final prospectus (the "Prospectus") dated April 30, 2015 and filed with the SEC, pursuant to Rule 424(b) under the Securities Act, on May 1, 2015. 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 "Company," "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 Prospectus.

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 actively managing our existing portfolio of mineral and royalty assets to maximize its value and expanding our asset base through acquisitions of additional mineral and royalty interests. We maximize value through marketing our mineral assets for lease, creatively structuring terms on those leases to encourage and accelerate drilling activity, and selectively participating alongside our lessees on a working-interest basis in low-risk development-drilling opportunities on our interests. Our primary business objective is to grow our reserves, production, and cash generated from operations over the long term, while paying, to the extent practicable, a growing quarterly distribution to our unitholders.

On May 1, 2015 our common units began trading on the New York Stock Exchange under the symbol "BSM." On May 6, 2015, we completed our initial public offering of 22,500,000 common units representing limited partner interests at a price to the public of $19.00 per common unit.

As of September 30, 2015, our mineral and royalty interests are located in over 40 states and 60 onshore basins in the continental United States. These non-cost-bearing interests include ownership in approximately 40,000 producing wells. We also own non-operated working interests, largely on our mineral and royalty interests. We recognize oil and natural gas revenue from our mineral and royalty and non-operated working interests in producing wells when the oil and natural gas production from the associated acreage is sold. Our other sources of revenue include mineral lease bonus and delay rentals, which are recognized as revenue according to the terms of the lease agreements.

Recent Developments

On October 20, 2015, the Company announced its intention to commence a cash tender offer to purchase up to 100% of the 117,963 outstanding preferred units from its preferred unitholders at the units' par value of $1,000.00 per preferred unit, plus unpaid accrued yield. The Company intends to fund the tender offer with cash on hand and funds available under its revolving credit facility. BSM commenced the proposed tender offer on November 6, 2015. The proposed tender offer will expire on December 10, 2015.

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. In the second half of 2014, oil prices began a rapid decline as global supply outpaced demand. In addition, in late November 2014, OPEC announced that it would not adjust its production targets. During the first nine months of 2015, oil price volatility continued with West Texas Intermediate ("WTI") spot prices ranging from a low of $38.22 per Bbl on August 24, 2015 to a high of $61.36 per Bbl on June 10, 2015. Concerns regarding a longer-term imbalance of supply and demand for oil have continued to weigh on oil prices. The WTI spot price settled at $46.12 per Bbl on November 2, 2015 and remains substantially below spot prices seen throughout much of 2014. Natural gas prices continue to be affected by an imbalance between supply and demand across North America. During the nine months ended September 30, 2015, Henry Hub spot natural gas prices ranged from a low of $2.47 per MMBtu on September 30, 2015 to a high of $3.32 per MMBtu on January 15, 2015. The Henry Hub spot price settled at $1.92 per MMBtu on November 2, 2015. To manage the variability in cash flows associated with the projected sale of our oil and natural gas production, we use various derivative instruments, which have generally consisted of costless collars and fixed-price swap contracts.

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

	2015			2014		
Benchmark Prices	**Third Quarter**	**Second Quarter**	**First Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
WTI spot oil price ($/Bbl)	$ 45.06	$ 59.48	$ 47.72	$ 91.17	$ 106.07	$ 101.57
Henry Hub spot natural gas ($/MMBtu)	$ 2.47	$ 2.80	$ 2.65	$ 4.14	$ 4.39	$ 4.48

Source: EIA

Rig Count

On a weekly basis, Baker Hughes Incorporated, an oilfield services company, releases a detailed report that provides information on the locations of oil and natural gas drilling rigs across the United States, Canada, and the Gulf of Mexico. The weekly rig count report provides insight into industry-wide trends regarding drilling activities in basins across the United States.

The following table shows the U.S. rig count at the close of each quarter for the periods presented:

	2015			2014		
U.S. Rotary Rig Count	**Third Quarter**	**Second Quarter**	**First Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
Oil	641	628	813	1,592	1,558	1,487
Natural gas	197	228	233	338	314	318
Other	—	3	2	1	1	4
Total	838	859	1,048	1,931	1,873	1,809

Source: Baker Hughes Incorporated

As we are not an operator, drilling on our acreage is dependent upon the exploration and production companies that lease our acreage. While we often have drilling plans from our operators related to their activities on our properties, we also monitor rig counts in an effort to identify existing and future leasing and drilling activity on our acreage.

Natural Gas Storage

Natural gas and natural gas liquids (“NGLs”) sales are a substantial portion of our total revenues and the majority of our total production. Natural gas prices are significantly influenced by storage levels throughout the year. The evaluation of our business and its outlook includes the regular monitoring of natural gas storage reports.

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.

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

	2015			2014		
Location	**Third Quarter**	**Second Quarter**	**First Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
			(Bcf)			
East[1]	1,804	1,109	522	1,714	923	310
West[2]	502	441	348	453	331	160
Producing[3]	1,232	1,027	591	933	675	352
Total	3,538	2,577	1,461	3,100	1,929	822

Source: EIA

[1] CT, DE, DC, FL, GA, IA, IL, IN, KY, MA, MD, ME, MI, MO, NC, NE, NH, NJ, NY, OH, PA, RI, SC, TN, VT, VA, WI, and WV
[2] AZ, CA, CO, ID, MN, MT, NV, ND, OR, SD, WA, WY, and UT
[3] AL, AR, KS, LA, MI, NM, OK, and TX

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 hedges; and
- EBITDA, Adjusted EBITDA, and cash available for distribution.

Volumes of Oil and Natural Gas Produced

In order to assess and track 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 variations.

Commodity Prices

Factors Affecting the Sales Price of Oil and Natural Gas

The prices we receive for oil, natural gas, and 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. As a result of our geographic diversification, we are not exposed to concentrated differential risks associated with any single play, trend, or basin.

- *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 on this benchmark with the final realized price affected by both quality and location differentials.

  The chemical composition of crude oil plays an important role in its refining and subsequent sale as petroleum products. As a result, variations in chemical composition relative to the benchmark crude oil, usually WTI, will result in price adjustments, which are often referred to as quality differentials. The characteristics that most significantly affect quality differentials include the density of the oil, 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 made up of 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 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 fixed-price swaps, costless collars, fixed-price contracts, and other contractual arrangements. We currently employ a "rolling hedge" strategy whereby we hedge 18 to 24 months into the future and replace those hedges with new ones as they settle or expire. The impact of these derivative instruments could affect the amount of revenue we ultimately realize. Throughout 2014, we entered into costless collars to mitigate the impact of price fluctuations. Costless collars are a combination of a purchased put option and a sold call option, in which the premiums net to zero. The sold call option eliminates the initial cost of the purchased put but places a ceiling price for the commodity being hedged. During the fourth quarter of 2014 and the nine months ended September 30, 2015, we also entered into fixed-price swap contracts. Under fixed-price swap contracts, a counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap strike price; conversely, we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap strike price. We may employ contractual arrangements other than costless collars and fixed-price swap contracts in the future to mitigate the impact of price fluctuations. If commodity prices decline in the future, our hedging contracts will partially mitigate the effect of lower prices on our future revenue.

Our open oil and natural gas derivative contracts as of September 30, 2015 are detailed within Note 4 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q. Our credit agreement limits the extent to which we can hedge our future production. Under the terms of our credit agreement, we are able to hedge estimated production from our proved developed producing reserves based on our most recently completed reserve report provided to our lenders. We do not enter into derivative instruments for speculative purposes. Including derivative contracts entered into subsequent to September 30, 2015, we have hedged 95.5%, 96.3%, and 49.7% of our estimated oil and condensate production and 98.1%, 97.5%, and 50.7% of our estimated natural gas production from our proved developed producing reserves for the remainder of 2015, 2016, and 2017, respectively.

Non-GAAP Financial Measures

EBITDA, Adjusted EBITDA, and cash available for distribution 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 EBITDA as net income (loss) before interest expense, income taxes and depreciation, depletion, and amortization. We define Adjusted EBITDA as EBITDA adjusted for impairment of oil and natural gas properties, accretion of ARO, unrealized gains and losses on derivative instruments, and non-cash equity-based compensation. We define cash available for distribution as Adjusted EBITDA plus or minus amounts for certain non-cash operating activities, borrowings for capital expenditures, capital expenditures, cash interest expense, and distributions to noncontrolling interests and preferred unitholders.

EBITDA, Adjusted EBITDA, and cash available for distribution should not be considered an alternative to, or more meaningful than, net income (loss), income (loss) from operations, cash flows from operating activities, or any other measure of financial performance presented in accordance with GAAP as measures of our financial performance. EBITDA, Adjusted EBITDA, and cash available for distribution have important limitations as analytical tools because they exclude some but not all items that affect net income (loss), the most directly comparable GAAP financial measure. Our computation of EBITDA, Adjusted EBITDA, and cash available for distribution may differ from computations of similarly titled measures of other companies.

The following table presents a reconciliation of EBITDA, Adjusted EBITDA, and cash available for distribution to net income, the most directly comparable GAAP financial measure, for the periods indicated.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(Unaudited) (In thousands)			
Net income (loss)	$ 53,892	$ 57,905	$ (51,575)	$ 189,900
Adjustments to reconcile to Adjusted EBITDA:				
Add:				
Depreciation, depletion and amortization	23,288	37,065	83,414	84,058
Interest expense	870	3,440	5,530	10,292
EBITDA	78,050	98,410	37,369	284,250
Add:				
Impairment of oil and natural gas properties	24,854	—	156,683	—
Accretion of asset retirement obligations	265	148	805	443
Equity-based compensation	5,690	1,798	13,052	7,452
Less:				
Unrealized gain on commodity derivative instruments	(44,053)	(9,108)	(10,918)	(3,708)
Adjusted EBITDA	64,806	91,248	196,991	288,437
Adjustments to reconcile to cash generated from operations:				
Add:				
Borrowings/cash used to fund capital expenditures	62,165	32,973	104,558	102,858
Loss on sales of assets, net	4	—	—	—
Less:				
Deferred revenue	(94)	—	(584)	(2,516)
Cash interest expense	(628)	(3,197)	(4,806)	(9,566)
Gain on sales of assets, net	—	—	(20)	—
Additions to and acquisitions of oil and natural gas properties	(62,165)	(32,973)	(104,558)	(102,858)
Cash generated from operations	64,088	88,051	191,581	276,355
Less:				
Cash paid to noncontrolling interests	(45)	(84)	(167)	(252)
Preferred unit distributions	(2,973)	(3,962)	(8,823)	(11,763)
Cash generated from operations available for distribution on common and subordinated units and reinvestment in our business	$ 61,070	$ 84,005	$ 182,591	$ 264,340

Factors Affecting the Comparability of Our Financial Results

Our historical financial condition and results of operations for the periods presented may not be comparable, either from period to period or going forward, because we will incur higher general and administrative expenses than in prior periods as a result of operating as a publicly traded partnership. These incremental expenses include costs associated with SEC reporting requirements, including annual and quarterly reports to unitholders; tax return and Schedule K-1 preparation and distribution; Sarbanes-Oxley Act compliance; New York Stock Exchange listing; independent registered public accounting firm fees; legal fees, investor-relations activities, registrar and transfer agent fees; director-and-officer insurance; and additional compensation. These direct, incremental general and administrative expenses are not included in our historical results of operations for periods prior to our IPO.

Results of Operations

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

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	(Unaudited) (Dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)	936	783	2,668	2,106
Natural gas (MMcf)[1]	10,411	10,945	31,817	31,173
Equivalents (MBoe)[2]	2,671	2,607	7,971	7,302
Realized prices:				
Oil and condensate ($/Bbl)	$ 47.15	$ 90.79	$ 47.45	$ 92.91
Natural gas ($/Mcf)[1]	$ 3.09	$ 4.19	$ 2.92	$ 5.02
Equivalents ($/Boe)[2]	$ 28.57	$ 44.88	$ 27.52	$ 48.24
Revenue:				
Oil and condensate sales	$ 44,128	$ 71,089	$ 126,584	$ 195,665
Natural gas and natural gas liquids sales	32,191	45,914	92,799	156,554
Gain on commodity derivative instruments	56,430	8,682	57,450	339
Lease bonus and other income	4,271	7,110	16,051	26,586
Total revenue	$ 137,020	$ 132,795	$ 292,884	$ 379,144

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 "Btu-equivalent" production volumes are presented on an oil-equivalent basis using a conversion factor of six Mcf of natural gas per barrel of "oil equivalent," which is based on approximate energy equivalency and does not reflect the price or value relationship between oil and natural gas.

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014

Revenue

Total revenues for the quarter ended September 30, 2015 increased $4.2 million, or 3.2%, compared to the quarter ended September 30, 2014. Production for the quarter ended September 30, 2015 averaged 29.0 MBoe per day, an increase of 0.7 MBoe per day, or 2.5%, compared to the corresponding period in 2014. The increase in total revenues is primarily due to a $47.7 million increase in gains on commodity derivative instruments and $11.6 million from higher production volumes partially offset by the effect of lower realized commodity prices, the impact of which totaled $52.3 million, and lower lease bonus of $2.8 million as compared to the corresponding period in 2014.

Oil and condensate sales. Oil and condensate sales during the period were $27.0 million, or 37.9%, lower than the third quarter of 2014 primarily due to lower realized prices. Our total oil and condensate production was 19.5% higher than the third quarter of 2014, but the increased production was more than offset by a 48.1% decline in realized prices. Our mineral-and-royalty-interest oil and condensate volumes accounted for 75.3% and 78.0% of total oil and condensate volumes for the quarters ended September 30, 2015 and 2014, respectively. Our mineral-and-royalty-interest oil and condensate volumes increased 15.6% in the third quarter of 2015 relative to the corresponding period in 2014, primarily driven by production increases from new wells in the Bakken/Three Forks and Eagle Ford plays. Our working-interest oil and condensate volumes increased by 34.4% to 2.5 MBbls per day during the third quarter of 2015 versus the same period in 2014 primarily due to volumes added from new wells in the Bakken/Three Forks and Wilcox plays.

Natural gas and natural gas liquids sales. Natural gas and NGL sales decreased by $13.7 million, or 29.9%, for the quarter ended September 30, 2015 as compared to the same period for 2014. A 26.3% decline in the realized natural gas and NGL price for the quarter ended September 30, 2015 versus the corresponding period in 2014 was primarily responsible for the decline in our natural gas and NGL revenues. A 4.9% decrease in production volumes also contributed to the decline in revenue.   Mineral-and-royalty-interest production accounted for 71.0% and 64.5% of our natural gas volumes for the quarters ended September 30, 2015 and 2014, respectively.

Gain on commodity derivative instruments. During the third quarter of 2015, we recognized $41.0 million of gains from oil commodity contracts, which included cash received of $9.9 million, compared to recognized gains of $7.3 million in the same period of 2014. During the third quarter of 2015, we recognized $15.4 million of gains from natural gas commodity contracts, which included cash received of $2.5 million, compared to recognized gains of $1.4 million in the same period of 2014.

Lease bonus and other income. When we lease our mineral interests, we generally receive an upfront cash payment, or a lease bonus. Lease bonus and other income decreased $2.8 million, or 40.0%, for the quarter ended September 30, 2015 as compared to the same period in 2014. In the third quarter of 2015, we successfully closed several significant lease transactions in the Wolfcamp play in West Texas and the Woodbine play in East Texas; however, overall lease bonus for activity during the quarter ended September 30, 2015 was lower than the same period of 2014. The timing of lease-bonus transactions is highly unpredictable and may vary significantly from quarter to quarter; however, lease-bonus income historically has been higher in the second half of the calendar year.

Operating Expense

Lease operating expense. Lease operating expense includes normally recurring expenses necessary to produce hydrocarbons from our non-operated working interests in oil and natural gas wells, as well as certain nonrecurring expenses, such as well repairs. Lease operating expense decreased $1.1 million, or 18.4%, for the quarter ended September 30, 2015 as compared to the same period in 2014, primarily due to lower costs associated with well service and workover costs.

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, 2015, production costs and ad valorem taxes decreased by $4.0 million, or 32.9%, from the quarter ended September 30, 2014, generally as a result of lower realized prices and estimated mineral reserve valuations.

Exploration expense. Exploration expense typically consists of geological and geophysical costs, including seismic costs, and are expensed as incurred under the successful efforts method of accounting. Exploration expense for the quarter ended September 30, 2015 increased by $1.4 million from the quarter ended September 30, 2014. This increase is due to 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 the mid-year and year-end reserve reports, except when circumstances indicate that there has been a significant change in reserves or costs. Depreciation, depletion, and amortization decreased $13.8 million, or 37.2%, for the quarter ended September 30, 2015 as compared to the same period in 2014, primarily due to the impact of a reduced cost basis resulting from impairment charges recorded during the prior twelve months that were partially offset by higher production rates.

Impairment of oil and natural gas properties. Individual categories of oil and natural gas properties are assessed periodically to determine if the net book value for these properties has been impaired. Management periodically conducts an in-depth evaluation of the cost of property acquisitions, successful exploratory wells, development activity, unproved leasehold, and mineral interests to identify impairments. Impairments totaled $24.9 million for the quarter ended September 30, 2015 primarily due to changes in reserve values resulting from declines in future expected realized net cash flows and other factors at September 30, 2015. There were no impairments for the third quarter of 2014.

General and administrative. General and administrative expenses are costs not directly associated with the production of oil and natural gas and include the cost of employee salaries and related benefits, office expenses, and fees for professional services. For the quarter ended September 30, 2015, general and administrative expenses increased by $3.4 million, or 21.4%, as compared to the same period in 2014. In 2015, costs attributable to our long-term incentive plan were $2.4 million higher than in the corresponding prior period due to an increase in incentive compensation awards granted subsequent to our IPO. We also incurred an additional $1.1 million of expense for our Sarbanes-Oxley Act compliance project and other consulting work during the three months ended September 30, 2015.

Interest expense. Interest expense decreased by $2.6 million, or 74.7%, due to lower borrowings under our credit facility. Outstanding borrowings during the third quarter of 2015 were lower than the third quarter of 2014 due to repayments made during the second quarter of 2015 towards our credit facility from proceeds received in our IPO.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Revenue

Total revenues for the nine months ended September 30, 2015 decreased $86.3 million, or 22.8%, compared to the quarter ended September 30, 2014. Production for the nine months ended September 30, 2015 averaged 29.2 MBoe per day, an increase of 2.5 MBoe per day, or 9.2%, compared to the corresponding period in 2014. The decrease in total revenues from the corresponding prior period is primarily due to the effect of lower realized commodity prices, the impact of which totaled $188.2 million, and the impact of $10.5 million lower lease bonus, partially offset by $55.4 million from higher production volumes and a $57.1 million difference in the impact of commodity derivative instruments.

Oil and condensate sales. Oil and condensate sales during the period were $69.1 million, or 35.3%, lower than the corresponding period in 2014 primarily due to lower realized prices. Our current period oil and condensate production was 26.7% higher than in the nine months ended September 30, 2014, but that was more than offset by a 48.9% decline in realized prices. Our mineral-and-royalty-interest oil and condensate volumes accounted for 76.6% and 76.0% of total oil and condensate volumes for the nine months ended September 30, 2015 and 2014, respectively. Our mineral-and-royalty-interest oil and condensate volumes increased 27.7% for the nine months ended September 30, 2015 relative to the corresponding period in 2014, primarily driven by production increases from new wells in the Bakken/Three Forks and Eagle Ford plays. Our working-interest oil and condensate volumes increased by 23.6% to 2.3 MBbls per day during the nine months ended September 30, 2015 versus the same period in 2014 primarily due to volumes added from new wells in the Bakken/Three Forks and Wilcox plays.

Natural gas and natural gas liquids sales. Natural gas and NGL sales decreased by $63.8 million, or 40.7%, for the nine months ended September 30, 2015 as compared to the same period for 2014. A 41.8% decline in the realized natural gas and NGL price for the nine months ended September 30, 2015 versus the corresponding period in 2014 was primarily responsible for the decline in our natural gas and NGL revenues. The unfavorable price variance was partially offset by a 2.1% increase in production volumes. This production increase was primarily generated by production from new wells in the Haynesville/Bossier and Wilcox plays. Mineral-and-royalty-interest production accounted for 67.0% and 68.9% of our natural gas volumes for the nine months ended September 30, 2015 and 2014, respectively.

Gain on commodity derivative instruments. During the nine months ended September 30, 2015, we recognized $37.3 million of gains from oil commodity contracts, which included $32.3 million in cash received, compared to a recognized gain of $0.8 million in the same period of 2014. During the first nine months of 2015, we recognized $20.1 million of gains from natural gas commodity contracts, which included $14.3 million of cash received, compared to a recognized loss of $0.5 million in the same period of 2014.

Lease bonus and other income. Lease bonus and other income decreased $10.5 million, or 39.6%, for the nine months ended September 30, 2015 as compared to the same period in 2014. In 2014, we successfully closed several leases in the Canyon Lime and Canyon Wash plays in north Texas and the Permian Basin; transactions of similar size were not replicated in the corresponding period of 2015. The timing of lease-bonus transactions is highly unpredictable and may vary significantly from quarter to quarter; however, lease-bonus income historically has been higher in the second half of the calendar year.

Operating Expense

Lease operating expense. Lease operating expense increased $0.8 million, or 5.3%, for the nine months ended September 30, 2015 as compared to the same period in 2014, primarily due to costs associated with higher production volumes for both oil and natural gas.

Production costs and ad valorem taxes. For the nine months ended September 30, 2015, production costs and ad valorem taxes decreased by $7.3 million, or 21.8%, from the nine months ended September 30, 2014, generally as a result of lower realized prices and estimated mineral reserve valuations.

Exploration expense. Exploration expense increased by $1.6 million for the nine months ended September 30, 2015 as compared to the same period in 2014, primarily due to 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 decreased $0.6 million, or 0.8%, for the nine months ended September 30, 2015 as compared to the same period in 2014, primarily due to higher production rates offset by the impact of a reduced cost basis resulting from impairment charges from prior periods.

Impairment of oil and natural gas properties. Impairments totaled $156.7 million for the nine months ended September 30, 2015 primarily due to changes in reserve values resulting from declines in future expected realized net cash flows. There were no impairments during the nine months ended September 30, 2014.

General and administrative. For the nine months ended September 30, 2015, general and administrative expenses increased by $7.9 million, or 17.4%, as compared to the same period in 2014. During 2015, personnel costs and costs attributable to our long-term incentive plan were $5.9 million higher than in the corresponding prior period primarily due to an increase in incentive compensation awards granted subsequent to our IPO. We also incurred an additional $1.9 million for our Sarbanes-Oxley Act compliance project and other consulting work during the nine months ended September 30, 2015.

Interest expense. Interest expense decreased by $4.8 million, or 46.3%, due to lower average outstanding borrowings under our credit facility. Outstanding borrowings during the first nine months of 2015 were lower than the nine months ended September 30, 2014, primarily due to payments made towards the outstanding balance of our credit facility subsequent to our IPO.

Liquidity and Capital Resources

Overview

Our primary sources of liquidity are cash generated from operations, borrowings under our credit facility, and proceeds from any future issuances 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 and working interests and the development of our oil and natural gas properties.

The board of directors of our general partner has adopted a policy pursuant to which distributions equal in amount to 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. We believe that we will generate sufficient cash from operations to pay the required distributions on the preferred units and the applicable minimum quarterly distributions on all the common and subordinated units outstanding. However, we do not have a legal or contractual obligation to pay distributions 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 unitholders in any quarter. Our minimum quarterly distribution provides the common unitholders a specified priority right to distributions over the subordinated unitholders if we pay distributions. The board of directors of our general partner may change the foregoing distribution policy at any time and from time to time.

We intend to finance our future acquisitions and working-interest capital needs with cash generated from operations, borrowings from our credit facility, and by accessing the capital markets. 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. We have set our initial distribution rate at a level we believe will allow us to retain in our business sufficient cash generated from our operations to satisfy our replacement capital expenditures needs and to fund a portion of our growth capital expenditures. The board of directors of our general partner is responsible for establishing the amount of our estimated replacement capital expenditures.

Cash Flows

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

	Nine Months Ended September 30,	
	2015	2014
	(Unaudited) (In thousands)	
Cash flows provided by operating activities	$ 217,165	$ 278,398
Cash flows used in investing activities	$ (104,222)	$ (92,545)
Cash flows used in financing activities	$ (122,176)	$ (207,984)

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Operating Activities. Our operating cash flow is dependent, in large part, on our production, realized commodity prices, lease-bonus revenue, and operating expenses. Our cash flow from operations decreased from $278.4 million for the nine months ended September 30, 2014 to $217.2 million for the nine months ended September 30, 2015. The decrease was primarily due to lower cash collections of $119.0 million related to oil and natural gas sales and lower lease bonus as compared to the corresponding period in 2014. In 2015, an increase of $49.9 million in operating cash flows related to the settlement of commodity derivative instruments partially offset the overall decrease in operating cash flows.

Investing Activities. Net cash used in investing activities increased by $11.7 million in the first nine months of 2015 as compared to the corresponding period in 2014 due to higher acquisition spend during the first nine months of 2015. Acquisition-related spend increased $16.7 million. A decrease of $4.8 million in capital expeditures for our working interests, net of sale proceeds, partially offset the increased acquisition spend during the period.

Financing Activities. For the nine months ended September 30, 2015, net cash used in financing activities decreased $85.8 million compared to the corresponding period in 2014. During the nine months ended September 30, 2015, we used net proceeds from our recently completed IPO to repay substantially all of our outstanding indebtedness under our credit facility. The proceeds received in excess of our net repayments resulted in a decrease in net cash used from the corresponding period in 2014.

Capital Expenditures

At the beginning of each calendar year, we establish a capital budget and then monitor it throughout the year. Our capital budgets are created based upon our estimate of internally generated cash flows and the ability to borrow and raise additional capital. Actual capital expenditure levels will vary, in part, based on actual internally generated cash, actual wells proposed by our operators for our participation, and the successful closing of acquisitions. The timing, size, and nature of acquisitions are unpredictable.

Our updated 2015 capital budget for drilling expenditures is $55.0 million. Approximately 49%, 25%, and 17% of our drilling capital budget will be spent in the Haynesville/Bossier, Bakken/Three Forks, and Wilcox plays, respectively, with the remainder being invested in various plays. During the nine months ended September 30, 2015, we incurred $39.3 million of drilling capital expenditures primarily in the aforementioned plays.

Credit Facility

On January 23, 2015, we amended and restated our $1.0 billion senior secured revolving credit agreement. Under this third amended and restated credit facility, the commitment of the lenders equals the lesser of the aggregate maximum credit amounts of the lenders and the borrowing base, which is determined based on the lenders' estimated value of our oil and natural gas properties. On October 28, 2015, the third amended and restated credit facility was further amended to extend the term of the agreement from February 3, 2017 to February 4, 2019. Borrowings under the third amended and restated credit facility may be used for the acquisition of properties, cash distributions, and other general corporate purposes. Our semi-annual borrowing base redetermination process resulted in a decrease of the borrowing base from $600.0 million to $550.0 million, effective October 28, 2015. Our next borrowing base redetermination is scheduled for April 2016. As of September 30, 2015, we had outstanding borrowings of $43.0 million at a weighted-average interest rate of 1.94%. We used net proceeds from our IPO in May 2015 to repay substantially all indebtedness outstanding under our credit facility.

The borrowing base under the third amended and restated credit agreement is redetermined semi-annually, on April 1 and October 1 of each year, by the administrative agent, taking into consideration the estimated loan value of our oil and gas properties consistent with the administrative agent's normal oil and gas 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 once in between scheduled redeterminations, to have the borrowing base redetermined.

Outstanding borrowings under the third amended and restated credit facility bear interest at a floating rate elected by us equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 1-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.50% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of borrowings outstanding in relation to the borrowing base. We are obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year 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. The facility is secured by liens on substantially all of our properties.

The third amended and restated credit agreement contains various affirmative, negative, and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements, and require the maintenance of certain financial ratios. The third amended and restated credit agreement contains two financial covenants: total debt to EBITDAX of 3.5:1.0 or less; and current assets to current liabilities of 1.0:1.0 or greater. Distributions are not permitted if there is a default under the third amended and restated 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 facility. The lenders have the right to accelerate all of the indebtedness under the third amended and restated credit facility upon the occurrence and during the continuance of any event of default, and the third amended and restated 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, 2015, we were in compliance with all debt covenants.

Contractual Obligations

As of September 30, 2015, there have been no material changes to our contractual obligations previously disclosed in the Prospectus.

Off-Balance Sheet Arrangements

As of September 30, 2015, we did not have any material off-balance sheet arrangements.

Critical Accounting Policies and Related Estimates

As of September 30, 2015, there have been no significant changes to our critical accounting policies and related estimates previously disclosed in the Prospectus.

New and Revised Financial Accounting Standards

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

Our major market risk exposure is the pricing of oil, natural gas, and natural gas liquids produced by our operators. Realized prices are primarily driven by the prevailing worldwide price for oil and U.S. spot market prices for natural gas and natural gas liquids. Prices for oil, natural gas, and natural gas liquids have been volatile for several years, and we expect this unpredictability to continue in the future. The prices that our operators receive for production depend on many factors outside of our or their control. To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we use commodity derivative contracts to reduce our exposure to price risk in the spot market for 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 has been based off 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 Notes 4 and 5 to the consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for additional information.

As previously discussed, commodity prices have fallen significantly this year. To estimate the effect of these lower prices on our reserves, we estimated reserves at September 30, 2015 by reducing our mid-year reserves at June 30, 2015 by estimated volumes produced in the three months ended September 30, 2015 and, without any further adjustments, applied SEC commodity pricing for the year ended December 31, 2014 and the nine months ended September 30, 2015, respectively, to that reserve base. The lower SEC commodity pricing from September 30, 2015 resulted in an approximate 10% reduction in reserves as compared to the December 31, 2014 SEC pricing.

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, 2015, we had ten counterparties, all of which are rated Baa2 or better by Moody's. Seven of our counterparties are lenders under our credit facility.

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

Interest Rate Risk

We have exposure to changes in interest rates on our indebtedness. As of September 30, 2015, we had $43.0 million of outstanding borrowings under our credit facility, bearing interest at a weighted-average interest rate of 1.94%. 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 $0.3 million for the nine months ended September 30, 2015, 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, 2015.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended September 30, 2015 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, you should carefully consider the risks under the heading "Risk Factors" in the Prospectus. Please refer below for an update to certain risk factors described in the Prospectus. 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.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative, or judicial changes or differing interpretations at any time. For example, the Obama administration's budget proposal for fiscal year 2016 recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. From time to time, members of Congress propose and consider such substantive changes to the existing federal income tax laws that affect publicly traded partnerships. If successful, the Obama administration's proposal or other similar proposals could eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations, upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

In addition, the IRS, on May 5, 2015, issued proposed regulations concerning which activities give rise to qualifying income within the meaning of Section 7704(d)(1)(E) of the Internal Revenue Code. The proposed regulations provide an exclusive list of industry-specific rules regarding the qualifying income exception, including whether an activity constitutes the exploration, development, production, and marketing of natural resources. Income earned from a royalty interest is not specifically enumerated as a qualifying income activity in the proposed regulations. However, notwithstanding the proposed regulations, our external counsel has advised us that royalty income is qualifying income for purposes of Section 7704 of the Internal Revenue Code since it is "derived" from the exploration, development, production, and marketing of natural resources. The U.S. Treasury Department and the IRS may clarify that royalty income is qualifying income for purposes of Section 7704 of the Internal Revenue Code; however, there are no assurances that the proposed regulations, when published as final regulations, will not take a position that is contrary to our interpretation of Section 7704 of the Internal Revenue Code.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted or adopted. Any such changes could negatively impact the value of an investment in our common units.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal income tax purposes, the minimum quarterly distribution and the target distribution amounts may be adjusted to reflect the impact of that law on us.

Item 6. Exhibits

The information required by this Item 6 is set forth in the Index to Exhibits accompanying this Quarterly Report on Form 10-Q and is incorporated herein by reference.

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 10, 2015	By:	/s/ Thomas L. Carter, Jr. Thomas L. Carter, Jr. President and Chief Executive Officer (Principal Executive Officer)
Date: November 10, 2015	By:	/s/ Marc Carroll Marc Carroll Senior Vice President and Chief Financial Officer (Principal Financial Officer)

Exhibit Index

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Black Stone Minerals, L.P. (incorporated herein by reference to Exhibit 3.1 to Black Stone Minerals, L.P.’s Registration Statement on Form S-1 filed on March 19, 2015 (SEC File No. 333-202875)).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Black Stone Minerals, L.P. (incorporated herein by reference to Exhibit 3.2 to Black Stone Minerals, L.P.’s Registration Statement on Form S-1 filed on March 19, 2015 (SEC File No. 333-202875)).
3.3	First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated May 6, 2015, by and among Black Stone Minerals GP, L.L.C. and Black Stone Minerals Company, L.P. (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.’s Current Report on Form 8-K filed on May 6, 2015 (SEC File No. 001-37362)).
*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.

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)) 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. 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

   c. 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 10, 2015

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

Exhibit 31.2

**CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Marc Carroll, 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)) 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. 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

   c. 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 10, 2015

/s/ Marc Carroll
Marc Carroll
Senior Vice President and Chief Financial Officer
Black Stone Minerals GP, L.L.C.,
the general partner of Black Stone Minerals, L.P.

Exhibit 32.1

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER
UNDER SECTION 906 OF THE
SARBANES OXLEY ACT OF 2002, 18 U.S.C. § 1350

In connection with the report on Form 10-Q of Black Stone Minerals, L.P. (the "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Thomas L. Carter, Jr., Chief Executive Officer of the Company, and Marc Carroll, Chief Financial Officer of the Company, 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 Company.

Date: November 10, 2015

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

Date: November 10, 2015

/s/ Marc Carroll
Marc Carroll
Senior Vice President and Chief Financial Officer
Black Stone Minerals GP, L.L.C.,
the general partner of Black Stone Minerals, L.P.