

**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 March 31, 2020

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)

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

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

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

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

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

| | | | |
|-------------------------|--|---------------------------|--------------------------|
| Large accelerated filer | <input checked="" type="checkbox"/> | Accelerated filer | <input type="checkbox"/> |
| Non-accelerated filer | <input type="checkbox"/> (Do not check if a smaller reporting company) | Smaller reporting company | <input type="checkbox"/> |
| | | Emerging growth company | <input type="checkbox"/> |

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

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

As of April 29, 2020, there were 206,709,448 common units and 14,711,219 Series B cumulative convertible preferred units of the registrant outstanding.

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PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

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

| | March 31, 2020 | December 31, 2019 |
|---|---------------------|---------------------|
| ASSETS | | |
| CURRENT ASSETS | | |
| Cash and cash equivalents | \$ 3,040 | \$ 8,119 |
| Accounts receivable | 58,464 | 78,214 |
| Commodity derivative assets | 96,278 | 14,790 |
| Prepaid expenses and other current assets | 1,995 | 1,168 |
| TOTAL CURRENT ASSETS | 159,777 | 102,291 |
| PROPERTY AND EQUIPMENT | | |
| Oil and natural gas properties, at cost, using the successful efforts method of accounting, includes unproved properties of \$1,073,475 and \$1,073,447 at March 31, 2020 and December 31, 2019, respectively | 3,291,755 | 3,302,340 |
| Accumulated depreciation, depletion, amortization, and impairment | (1,938,773) | (1,870,412) |
| Oil and natural gas properties, net | 1,352,982 | 1,431,928 |
| Other property and equipment, net of accumulated depreciation of \$11,792 and \$11,622 at March 31, 2020 and December 31, 2019, respectively | 2,132 | 2,300 |
| NET PROPERTY AND EQUIPMENT | 1,355,114 | 1,434,228 |
| DEFERRED CHARGES AND OTHER LONG-TERM ASSETS | 7,676 | 8,689 |
| TOTAL ASSETS | \$ 1,522,567 | \$ 1,545,208 |
| LIABILITIES, MEZZANINE EQUITY, AND EQUITY | | |
| CURRENT LIABILITIES | | |
| Accounts payable | \$ 563 | \$ 5,309 |
| Accrued liabilities | 8,823 | 22,702 |
| Commodity derivative liabilities | — | 159 |
| Other current liabilities | 1,412 | 1,633 |
| TOTAL CURRENT LIABILITIES | 10,798 | 29,803 |
| LONG-TERM LIABILITIES | | |
| Credit facility | 388,000 | 394,000 |
| Accrued incentive compensation | 543 | 2,110 |
| Commodity derivative liabilities | — | 18 |
| Asset retirement obligations | 16,225 | 15,653 |
| Other long-term liabilities | 4,914 | 6,820 |
| TOTAL LIABILITIES | 420,480 | 448,404 |
| COMMITMENTS AND CONTINGENCIES (Note 7) | | |
| MEZZANINE EQUITY | | |
| Partners' equity – Series B cumulative convertible preferred units, 14,711 units outstanding at March 31, 2020 and December 31, 2019 | 298,361 | 298,361 |
| EQUITY | | |
| Partners' equity – general partner interest | — | — |
| Partners' equity – common units, 206,695 and 205,960 units outstanding at March 31, 2020 and December 31, 2019, respectively | 803,726 | 798,443 |
| TOTAL EQUITY | 803,726 | 798,443 |
| TOTAL LIABILITIES, MEZZANINE EQUITY, AND EQUITY | \$ 1,522,567 | \$ 1,545,208 |

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

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

| | Three Months Ended March 31, | |
|--|---------------------------------|-----------------|
| | 2020 | 2019 |
| REVENUE | | |
| Oil and condensate sales | \$ 52,093 | \$ 57,704 |
| Natural gas and natural gas liquids sales | 36,642 | 61,640 |
| Lease bonus and other income | 4,308 | 5,645 |
| Revenue from contracts with customers | 93,043 | 124,989 |
| Gain (loss) on commodity derivative instruments | 90,011 | (41,183) |
| TOTAL REVENUE | 183,054 | 83,806 |
| OPERATING (INCOME) EXPENSE | | |
| Lease operating expense | 3,827 | 5,292 |
| Production costs and ad valorem taxes | 12,376 | 14,592 |
| Exploration expense | 1 | 4 |
| Depreciation, depletion, and amortization | 23,182 | 27,833 |
| Impairment of oil and natural gas properties | 51,031 | — |
| General and administrative | 11,856 | 21,214 |
| Accretion of asset retirement obligations | 272 | 277 |
| TOTAL OPERATING EXPENSE | 102,545 | 69,212 |
| INCOME (LOSS) FROM OPERATIONS | 80,509 | 14,594 |
| OTHER INCOME (EXPENSE) | | |
| Interest and investment income | 31 | 46 |
| Interest expense | (4,427) | (5,525) |
| Other income (expense) | (1) | (98) |
| TOTAL OTHER EXPENSE | (4,397) | (5,577) |
| NET INCOME (LOSS) | 76,112 | 9,017 |
| Distributions on Series B cumulative convertible preferred units | (5,250) | (5,250) |
| NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON AND SUBORDINATED UNITS | \$ 70,862 | \$ 3,767 |
| ALLOCATION OF NET INCOME (LOSS): | | |
| General partner interest | \$ — | \$ — |
| Common units | 70,862 | 1,905 |
| Subordinated units | — | 1,862 |
| | \$ 70,862 | \$ 3,767 |
| NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON AND SUBORDINATED UNIT: | | |
| Per common unit (basic) | \$ 0.34 | \$ 0.02 |
| Weighted average common units outstanding (basic) | 206,631 | 109,420 |
| Per subordinated unit (basic) | \$ — | \$ 0.02 |
| Weighted average subordinated units outstanding (basic) | — | 96,329 |
| Per common unit (diluted) | \$ 0.34 | \$ 0.02 |
| Weighted average common units outstanding (diluted) | 206,631 | 110,035 |
| Per subordinated unit (diluted) | \$ — | \$ 0.02 |
| Weighted average subordinated units outstanding (diluted) | — | 96,329 |

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

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

| | Common units | Partners' equity — common units | Total equity |
|--|----------------|---------------------------------|-------------------|
| BALANCE AT DECEMBER 31, 2019 | 205,960 | \$ 798,443 | \$ 798,443 |
| Repurchases of common units | (503) | (5,029) | (5,029) |
| Restricted units granted, net of forfeitures | 1,238 | — | — |
| Equity-based compensation | — | 1,159 | 1,159 |
| Distributions | — | (61,641) | (61,641) |
| Charges to partners' equity for accrued distribution equivalent rights | — | (68) | (68) |
| Distributions on Series B cumulative convertible preferred units | — | (5,250) | (5,250) |
| Net income (loss) | — | 76,112 | 76,112 |
| BALANCE AT MARCH 31, 2020 | 206,695 | \$ 803,726 | \$ 803,726 |

| | Common units | Subordinated units | Partners' equity — common units | Partners' equity — subordinated units | Total equity |
|--|----------------|--------------------|---------------------------------|---------------------------------------|-------------------|
| BALANCE AT DECEMBER 31, 2018 | 108,363 | 96,329 | \$ 714,823 | \$ 189,440 | \$ 904,263 |
| Repurchases of common units | (588) | — | (10,110) | — | (10,110) |
| Issuance of common units, net of offering costs | — | — | (43) | — | (43) |
| Issuance of common units for property acquisitions | 57 | — | 943 | — | 943 |
| Restricted units granted, net of forfeitures | 1,545 | — | — | — | — |
| Equity-based compensation | — | — | 13,669 | — | 13,669 |
| Distributions | — | — | (40,275) | (35,642) | (75,917) |
| Charges to partners' equity for accrued distribution equivalent rights | — | — | (1,044) | — | (1,044) |
| Distributions on Series B cumulative convertible preferred units | — | — | (5,250) | — | (5,250) |
| Net income (loss) | — | — | 7,155 | 1,862 | 9,017 |
| BALANCE AT MARCH 31, 2019 | 109,377 | 96,329 | \$ 679,868 | \$ 155,660 | \$ 835,528 |

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

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

| | Three Months Ended March 31, | |
|--|------------------------------|-----------------|
| | 2020 | 2019 |
| CASH FLOWS FROM OPERATING ACTIVITIES | | |
| Net income (loss) | \$ 76,112 | \$ 9,017 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | |
| Depreciation, depletion, and amortization | 23,182 | 27,833 |
| Impairment of oil and natural gas properties | 51,031 | — |
| Accretion of asset retirement obligations | 272 | 277 |
| Amortization of deferred charges | 260 | 257 |
| (Gain) loss on commodity derivative instruments | (90,011) | 41,183 |
| Net cash (paid) received on settlement of commodity derivative instruments | 8,954 | 1,743 |
| Equity-based compensation | (2,894) | 9,223 |
| Exploratory dry hole expense | — | 4 |
| Changes in operating assets and liabilities: | | |
| Accounts receivable | 19,693 | 9,740 |
| Prepaid expenses and other current assets | (827) | (541) |
| Accounts payable, accrued liabilities, and other | (14,269) | (8,522) |
| Settlement of asset retirement obligations | (53) | (40) |
| NET CASH PROVIDED BY OPERATING ACTIVITIES | 71,450 | 90,174 |
| CASH FLOWS FROM INVESTING ACTIVITIES | | |
| Acquisitions of oil and natural gas properties | (28) | (19,946) |
| Additions to oil and natural gas properties | (3,548) | (31,633) |
| Additions to oil and natural gas properties leasehold costs | — | (234) |
| Purchases of other property and equipment | (2) | (2,036) |
| Proceeds from the sale of oil and natural gas properties | 1,266 | 2 |
| Proceeds from farmouts of oil and natural gas properties | 3,703 | 29,468 |
| NET CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES | 1,391 | (24,379) |
| CASH FLOWS FROM FINANCING ACTIVITIES | | |
| Proceeds from issuance of common units, net of offering costs | — | (43) |
| Distributions to common and subordinated unitholders | (61,641) | (75,917) |
| Distributions to Series B cumulative convertible preferred unitholders | (5,250) | (5,250) |
| Repurchases of common units | (5,029) | (10,752) |
| Borrowings under credit facility | 67,000 | 98,000 |
| Repayments under credit facility | (73,000) | (73,000) |
| NET CASH USED IN FINANCING ACTIVITIES | (77,920) | (66,962) |
| NET CHANGE IN CASH AND CASH EQUIVALENTS | (5,079) | (1,167) |
| CASH AND CASH EQUIVALENTS – beginning of the period | 8,119 | 5,414 |
| CASH AND CASH EQUIVALENTS – end of the period | \$ 3,040 | \$ 4,247 |
| SUPPLEMENTAL DISCLOSURE | | |
| Interest paid | \$ 4,173 | \$ 5,197 |

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

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - BUSINESS AND BASIS OF PRESENTATION

Description of the Business

Black Stone Minerals, L.P. ("BSM" or the "Partnership") is a publicly traded Delaware limited partnership that owns oil and natural gas mineral interests, which make up the vast majority of the asset base. The Partnership's assets also include nonparticipating royalty interests and overriding royalty interests. These interests, which are substantially non-cost-bearing, are collectively referred to as "mineral and royalty interests." The Partnership's mineral and royalty interests are located in 41 states in the continental United States, including all of the major onshore producing basins. The Partnership also owns non-operated working interests in certain oil and natural gas properties. The Partnership's common units trade on the New York Stock Exchange under the symbol "BSM."

Basis of Presentation

The accompanying unaudited interim consolidated financial statements of the Partnership have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States and pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). These unaudited interim consolidated financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with GAAP. Accordingly, the accompanying unaudited interim consolidated financial statements and related notes should be read in conjunction with the Partnership's consolidated financial statements included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2019 ("2019 Annual Report on Form 10-K").

The unaudited interim consolidated financial statements include the consolidated results of the Partnership. The results of operations for the three months ended March 31, 2020 are not necessarily indicative of the results to be expected for the full year.

In the opinion of management, all adjustments, which are of a normal and recurring nature, necessary for the fair presentation of the financial results for all periods presented have been reflected. All intercompany balances and transactions have been eliminated.

The Partnership evaluates the significant terms of its investments to determine the method of accounting to be applied to each respective investment. Investments in which the Partnership has less than a 20% ownership interest and does not have control or exercise significant influence are accounted for using fair value or cost minus impairment if fair value is not readily determinable. Investments in which the Partnership exercises control are consolidated, and the noncontrolling interests of such investments, which are not attributable directly or indirectly to the Partnership, are presented as a separate component of net income (loss) and equity.

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

Segment Reporting

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

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Significant Accounting Policies

Significant accounting policies are disclosed in the Partnership's 2019 Annual Report on Form 10-K. There have been no changes in such policies or the application of such policies during the three months ended March 31, 2020.

Accounts Receivable

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

| | March 31, 2020 | December 31, 2019 |
|--|------------------|-------------------|
| | (in thousands) | |
| Accounts receivable: | | |
| Revenues from contracts with customers | \$ 53,652 | \$ 71,022 |
| Other | 4,812 | 7,192 |
| Total accounts receivable | <u>\$ 58,464</u> | <u>\$ 78,214</u> |

Recent Accounting Pronouncements

On January 1, 2020, the Partnership adopted Accounting Standards Update ("ASU") 2018-13, *Fair Value Measurements (Topic 820)*, which removed, modified, and added certain required disclosures on fair value measurements. The adoption of this update had no impact on the Partnership's financial position, results of operations, or liquidity.

NOTE 3 - OIL AND NATURAL GAS PROPERTIES

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

2020 Acquisitions

The Partnership had no acquisition activity during the three months ended March 31, 2020.

2019 Acquisitions

During the year ended December 31, 2019, the Partnership closed on multiple acquisitions of mineral and royalty interests for total consideration of \$44.0 million.

Acquisitions that were considered business combinations were primarily located in the Permian Basin. These acquisitions were funded with borrowings under the Credit Facility (as defined in Note 6 - Credit Facility) and funds from operating activities. Acquisition related costs of less than \$0.1 million were expensed and included in the General and administrative line item of the consolidated statement of operations for the year ended December 31, 2019. The following table summarizes these acquisitions:

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

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

In addition, during 2019, the Partnership acquired mineral and royalty interests that were considered asset acquisitions from various sellers for an aggregate of \$31.6 million. These acquisitions were primarily located in East Texas and the Permian Basin. The cash portion of the consideration paid for these acquisitions of \$30.7 million was funded with borrowings under the Credit Facility and funds from operating activities, and \$0.9 million was funded through the issuance of common units of the Partnership based on the fair values of the common units issued on the acquisition dates.

Farmout Agreements

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

Canaan Farmout

On February 21, 2017, the Partnership announced that it had entered into a farmout agreement with Canaan Resource Partners ("Canaan") which covers certain Haynesville and Bossier shale acreage in San Augustine County, Texas operated by XTO Energy Inc., a subsidiary of Exxon Mobil Corporation. The Partnership has an approximate 50% working interest in the acreage and is the largest mineral owner. A total of 20 wells were drilled over an initial phase, beginning with wells spud after January 1, 2017. Canaan elected to participate in an additional phase that began in September 2018 and continues for the lesser of 2 years or until 20 wells have been drilled. As of March 31, 2020, a total of 17 wells have been drilled during the second phase. After the completion of the second phase, Canaan will have the option to elect to participate in a similar third phase. During the first three phases of the agreement, Canaan commits on a phase-by-phase basis and funds 80% of the Partnership's drilling and completion costs and is assigned 80% of the Partnership's working interests in such wells (40% working interest on an 8/8ths basis) as the wells are drilled. After the third phase, Canaan can earn 40% of the Partnership's working interest (20% working interest on an 8/8ths basis) in additional wells drilled in the area by continuing to fund 40% of the Partnership's costs for those wells on a well-by-well basis. The Partnership receives an overriding royalty interest ("ORRI") before payout and an increased ORRI after payout on all wells drilled under the agreement.

Pivotal Farmout

On November 21, 2017, the Partnership entered into a farmout agreement with Pivotal Petroleum Partners ("Pivotal"), a portfolio company of Tailwater Capital, LLC. The farmout agreement covers substantially all of the Partnership's remaining working interests under active development in the Shelby Trough area of East Texas, targeting the Haynesville and Bossier shale acreage (after giving effect to the Canaan Farmout), until November 2025. Pivotal will earn the Partnership's remaining working interest in wells operated by XTO Energy Inc. in San Augustine County, Texas not covered by the Canaan Farmout (10% working interest on an 8/8th basis), as well as 100% of the Partnership's working interests (ranging from approximately 12.5% to 25% on an 8/8ths basis) in wells operated by BPX Energy in San Augustine and Angelina counties, Texas. Initially, Pivotal is obligated to fund the development of up to 80 wells, in designated well groups, across several development areas and then has options to continue funding the Partnership's working interest across those areas for the duration of the farmout agreement. Once Pivotal achieves a specified payout for a designated well group, the Partnership will obtain a majority of the original working interest in such well group. As of March 31, 2020, a total of 68 wells have been drilled in the contract area. The Partnership's development agreement with BPX Energy terminated in 2019 with respect to the majority of the Partnership's acreage covered by the farmout agreement with Pivotal. As such, Pivotal retains minimal rights or obligations related to the farmout for that area. The Partnership remains engaged with Pivotal around farmout opportunities with potential new operators in the area forfeited by BPX Energy.

From the inception of the farmout agreements through March 31, 2020, the Partnership has received \$90.3 million and \$118.6 million from Canaan and Pivotal, respectively, under the agreements. When such reimbursements are received prior to assigning the wells to Canaan and Pivotal, the Partnership records the amounts as increases to Oil and natural gas properties and Other long-term liabilities. When working interests in farmout wells are assigned to Canaan and Pivotal, the Partnership's Oil and natural gas properties and Other long-term liabilities are reduced by the reimbursed capital costs. As of March 31, 2020 and December 31, 2019, \$0.1 million and \$1.7 million, respectively, was included in the Other long-term liabilities line item of the consolidated balance sheets for reimbursements received associated with farmed-out working interests not yet assigned to Canaan and Pivotal.

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

Impairment of Oil and Natural Gas Properties

Proved and unproved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of those properties. When assessing producing properties for impairment, the Partnership compares the expected undiscounted projected future cash flows of the producing properties to the carrying amount of the producing properties to determine recoverability. When the carrying amount exceeds its estimated undiscounted future cash flows, the carrying amount is written down to its fair value, which is measured as the present value of the projected future cash flows of such properties.

There was a collapse in oil prices during the first quarter of 2020 due to geopolitical events that increased supply at the same time demand weakened due to the impact of the COVID-19 pandemic. The Partnership determined these events and circumstances indicated a possible decline in the recoverability of the carrying value of certain proved properties and recoverability testing determined that certain depletable units consisting of mature oil producing properties were impaired. The Partnership recognized impairment of oil and natural gas properties of \$51.0 million for three months ended March 31, 2020. No impairment of oil and natural gas properties was recognized during 2019. See Note 5 - Fair Value Measurements for further discussion

NOTE 4 - COMMODITY DERIVATIVE FINANCIAL INSTRUMENTS

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

As of March 31, 2020, the Partnership's open derivative contracts consisted of fixed-price swap contracts and costless collar contracts. A fixed-price swap contract between the Partnership and the counterparty specifies a fixed commodity price and a future settlement date. A costless collar contract between the Partnership and the counterparty specifies a floor and a ceiling commodity price and a future settlement date. The Partnership has not designated any of its contracts as fair value or cash flow hedges. Accordingly, the changes in the fair value of the contracts are included in the consolidated statement of operations in the period of the change. All derivative gains and losses from the Partnership's derivative contracts have been recognized in revenue in the Partnership's accompanying consolidated statements of operations. Derivative instruments that have not yet been settled in cash are reflected as either derivative assets or liabilities in the Partnership's accompanying consolidated balance sheets as of March 31, 2020 and December 31, 2019. See Note 5 - Fair Value Measurements for further discussion.

The Partnership's derivative contracts expose it to credit risk in the event of nonperformance by counterparties that may adversely impact the fair value of the Partnership's commodity derivative assets. While the Partnership does not require its derivative contract counterparties to post collateral, the Partnership does evaluate the credit standing of such counterparties as deemed appropriate. This evaluation includes reviewing a counterparty's credit rating and latest financial information. As of March 31, 2020, the Partnership had eight counterparties, all of which are rated Baa1 or better by Moody's and are lenders under the Credit Facility.

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

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

| Classification | Balance Sheet Location | March 31, 2020 | | |
|---------------------|---|------------------|--------------------------------|-------------------------------------|
| | | Gross Fair Value | Effect of Counterparty Netting | Net Carrying Value on Balance Sheet |
| (in thousands) | | | | |
| Assets: | | | | |
| Current asset | Commodity derivative assets | \$ 96,294 | \$ (16) | \$ 96,278 |
| Long-term asset | Deferred charges and other long-term assets | — | — | — |
| Total assets | | <u>\$ 96,294</u> | <u>\$ (16)</u> | <u>\$ 96,278</u> |
| Liabilities: | | | | |
| Current liability | Commodity derivative liabilities | \$ 16 | \$ (16) | \$ — |
| Long-term liability | Commodity derivative liabilities | — | — | — |
| Total liabilities | | <u>\$ 16</u> | <u>\$ (16)</u> | <u>\$ —</u> |

| Classification | Balance Sheet Location | December 31, 2019 | | |
|---------------------|---|-------------------|--------------------------------|-------------------------------------|
| | | Gross Fair Value | Effect of Counterparty Netting | Net Carrying Value on Balance Sheet |
| (in thousands) | | | | |
| Assets: | | | | |
| Current asset | Commodity derivative assets | \$ 19,028 | \$ (4,238) | \$ 14,790 |
| Long-term asset | Deferred charges and other long-term assets | 713 | (105) | 608 |
| Total assets | | <u>\$ 19,741</u> | <u>\$ (4,343)</u> | <u>\$ 15,398</u> |
| Liabilities: | | | | |
| Current liability | Commodity derivative liabilities | \$ 4,397 | \$ (4,238) | \$ 159 |
| Long-term liability | Commodity derivative liabilities | 123 | (105) | 18 |
| Total liabilities | | <u>\$ 4,520</u> | <u>\$ (4,343)</u> | <u>\$ 177</u> |

Changes in the fair values of the Partnership's derivative instruments (both assets and liabilities) are presented on a net basis in the accompanying consolidated statements of operations and consolidated statements of cash flows and consist of the following for the periods presented:

| Derivatives not designated as hedging instruments | Three Months Ended March 31, | |
|---|------------------------------|-----------------|
| | 2020 | 2019 |
| (in thousands) | | |
| Beginning fair value of commodity derivative instruments | \$ 15,221 | \$ 48,038 |
| Gain (loss) on oil derivative instruments | 77,811 | (39,261) |
| Gain (loss) on natural gas derivative instruments | 12,200 | (1,922) |
| Net cash paid (received) on settlements of oil derivative instruments | (1,541) | (4,555) |
| Net cash paid (received) on settlements of natural gas derivative instruments | (7,413) | 2,812 |
| Net change in fair value of commodity derivative instruments | <u>81,057</u> | <u>(42,926)</u> |
| Ending fair value of commodity derivative instruments | <u>\$ 96,278</u> | <u>\$ 5,112</u> |

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

The Partnership had the following open derivative contracts for oil as of March 31, 2020:

| Period and Type of Contract | Volume (Bbl) | Weighted Average Price (Per Bbl) | Range (Per Bbl) | |
|-----------------------------|--------------|----------------------------------|-----------------|----------|
| | | | Low | High |
| Oil Swap Contracts: | | | | |
| 2020 | | | | |
| First Quarter | 210,000 | \$ 57.32 | \$ 54.92 | \$ 58.65 |
| Second Quarter | 630,000 | 57.32 | 54.92 | 58.65 |
| Third Quarter | 630,000 | 57.32 | 54.92 | 58.65 |
| Fourth Quarter | 630,000 | 57.32 | 54.92 | 58.65 |

| Period and Type of Contract | Volume (Bbl) | Weighted Average Floor Price (Per Bbl) | Weighted Average Ceiling Price (Per Bbl) | |
|------------------------------|--------------|--|--|------|
| | | | Low | High |
| Oil Collar Contracts: | | | | |
| 2020 | | | | |
| First Quarter | 70,000 | \$ 56.43 | \$ 67.14 | |
| Second Quarter | 210,000 | 56.43 | 67.14 | |
| Third Quarter | 210,000 | 56.43 | 67.14 | |
| Fourth Quarter | 210,000 | 56.43 | 67.14 | |

The Partnership had the following open derivative contracts for natural gas as of March 31, 2020:

| Period and Type of Contract | Volume (MMBtu) | Weighted Average Price (Per MMBtu) | Range (Per MMBtu) | |
|------------------------------------|----------------|------------------------------------|-------------------|---------|
| | | | Low | High |
| Natural Gas Swap Contracts: | | | | |
| 2020 | | | | |
| Second Quarter | 10,010,000 | \$ 2.69 | \$ 2.55 | \$ 2.74 |
| Third Quarter | 10,120,000 | 2.69 | 2.55 | 2.74 |
| Fourth Quarter | 10,120,000 | 2.69 | 2.55 | 2.74 |

The Partnership entered into the following derivative contracts for oil subsequent to March 31, 2020:

| Period and Type of Contract | Volume (Bbl) | Weighted Average Price (Per Bbl) | Range (Per Bbl) | |
|-----------------------------|--------------|----------------------------------|-----------------|----------|
| | | | Low | High |
| Oil Swap Contracts: | | | | |
| 2021 | | | | |
| First Quarter | 480,000 | \$ 36.18 | \$ 32.64 | \$ 37.92 |
| Second Quarter | 480,000 | 36.18 | 32.64 | 37.92 |
| Third Quarter | 480,000 | 36.18 | 32.64 | 37.92 |
| Fourth Quarter | 480,000 | 36.18 | 32.64 | 37.92 |

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

The Partnership entered into the following derivative contracts for natural gas subsequent to March 31, 2020:

| Period and Type of Contract | Volume (MMBtu) | Weighted Average Price (Per MMBtu) | Range (Per MMBtu) | |
|------------------------------------|----------------|---------------------------------------|-------------------|---------|
| | | | Low | High |
| Natural Gas Swap Contracts: | | | | |
| 2021 | | | | |
| First Quarter | 7,200,000 | \$ 2.60 | \$ 2.52 | \$ 2.72 |
| Second Quarter | 7,280,000 | 2.60 | 2.52 | 2.72 |
| Third Quarter | 7,360,000 | 2.60 | 2.52 | 2.72 |
| Fourth Quarter | 7,360,000 | 2.60 | 2.52 | 2.72 |

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 5 - FAIR VALUE MEASUREMENTS

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

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

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

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

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

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Partnership's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability.

The carrying value of the Partnership's cash and cash equivalents, receivables, and payables approximate fair value due to the short-term nature of the instruments. The estimated carrying value of all debt as of March 31, 2020 and December 31, 2019 approximated the fair value due to variable market rates of interest. These debt fair values, which are Level 3 measurements, were estimated based on the Partnership's incremental borrowing rates for similar types of borrowing arrangements, when quoted market prices were not available. The estimated fair values of the Partnership's financial instruments are not necessarily indicative of the amounts that would be realized in a current market exchange.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The Partnership estimated the fair value of derivative instruments using the market approach via a model that uses inputs that are observable in the market or can be derived from, or corroborated by, observable data. See Note 4 - Commodity Derivative Financial Instruments for further discussion.

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

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

| | Fair Value Measurements Using | | | Effect of Counterparty Netting | Total |
|----------------------------------|-------------------------------|-----------|---------|-----------------------------------|-----------|
| | Level 1 | Level 2 | Level 3 | | |
| (in thousands) | | | | | |
| As of March 31, 2020 | | | | | |
| Financial Assets | | | | | |
| Commodity derivative instruments | \$ — | \$ 96,294 | \$ — | \$ (16) | \$ 96,278 |
| Financial Liabilities | | | | | |
| Commodity derivative instruments | \$ — | \$ 16 | \$ — | \$ (16) | \$ — |
| As of December 31, 2019 | | | | | |
| Financial Assets | | | | | |
| Commodity derivative instruments | \$ — | \$ 19,741 | \$ — | \$ (4,343) | \$ 15,398 |
| Financial Liabilities | | | | | |
| Commodity derivative instruments | \$ — | \$ 4,520 | \$ — | \$ (4,343) | \$ 177 |

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

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

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

Oil and natural gas properties are measured at fair value on a non-recurring basis using the income approach when assessing for impairment. The factors used to determine fair value include estimates of proved reserves, future commodity prices, timing of future production, operating costs, future capital expenditures, and a risk-adjusted discount rate. The Partnership estimated the fair value of the impaired properties for the three months ended March 31, 2020 using published forward commodity price curves as of the measurement date of March 31, 2020, considering locational and quality differentials based on a review of historical realizations. The following table presents information about the non-recurring fair value measurements of the impaired properties, including the applicable risk-adjusted discount rate utilized in the assessment:

| | Fair Value Measurements Using | | | Impairment | Annual Discount Rate |
|--|-------------------------------|---------|----------|------------|----------------------|
| | Level 1 | Level 2 | Level 3 | | |
| (in thousands) | | | | | |
| Three Months Ended March 31, 2020 | | | | | |
| Impaired oil and natural gas properties | \$ — | \$ — | \$ 2,044 | \$ 51,031 | 8 % |
| Three Months Ended March 31, 2019 | | | | | |
| Impaired oil and natural gas properties | \$ — | \$ — | \$ — | \$ — | |

The Partnership's estimates of fair value have been determined at discrete points in time based on relevant market data. These estimates involve uncertainty, particularly in the current volatile market, and cannot be determined with precision. Changes to these estimates, particularly related to economic reserves, future commodity prices, and timing of future production could result in additional impairment charges in the future. There were no significant changes in valuation techniques or related inputs as of March 31, 2020 or December 31, 2019.

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 6 - CREDIT FACILITY

The Partnership maintains a senior secured revolving credit agreement, as amended (the "Credit Facility"). The Credit Facility has an aggregate maximum credit amount of \$1.0 billion and terminates on November 1, 2022. The commitment of the lenders equals the lesser of the aggregate maximum credit amount and the borrowing base. The amount of the borrowing base is redetermined semi-annually, usually in October and April, and is derived from the value of the Partnership's oil and natural gas properties as determined by the lender syndicate using pricing assumptions that often differ from the current market for future prices. The Partnership and the lenders (at the direction of two-thirds of the lenders) each have discretion to request a borrowing base redetermination one time between scheduled redeterminations. Effective October 23, 2019 the borrowing base redetermination reduced the borrowing base from \$675.0 million to \$650.0 million and, effective May 1, 2020, the borrowing base was further reduced to \$460.0 million.

Outstanding borrowings under the Credit Facility bear interest at a floating rate elected by the Partnership equal to an alternative base rate (which is equal to the greatest of the Prime Rate, the Federal Funds effective rate plus 0.50%, or 1-month LIBOR plus 1.00%) or LIBOR, in each case, plus the applicable margin. The applicable margin for the alternative base rate ranges from 0.75% to 1.75% and the applicable margin for LIBOR ranges from 1.75% to 2.75%, depending on the borrowings outstanding in relation to the borrowing base.

The weighted-average interest rate of the Credit Facility was 3.22% and 4.05% as of March 31, 2020 and December 31, 2019, respectively. Accrued interest is payable at the end of each calendar quarter or at the end of each interest period, unless the interest period is longer than 90 days, in which case interest is payable at the end of every 90-day period. In addition, a commitment fee is payable at the end of each calendar quarter based on either a rate of 0.375% if the borrowing base utilization percentage is less than 50%, or 0.500% if the borrowing base utilization percentage is equal to or greater than 50%. The Credit Facility is secured by substantially all of the Partnership's oil and natural gas production and assets.

The Credit Facility contains various limitations on future borrowings, leases, hedging, and sales of assets. Additionally, the Credit Facility requires the Partnership to maintain a current ratio of not less than 1.0:1.0 and a ratio of total debt to EBITDAX (Earnings before Interest, Taxes, Depreciation, Amortization, and Exploration) of not more than 3.5:1.0. As of March 31, 2020, the Partnership was in compliance with all financial covenants in the Credit Facility.

The aggregate principal balance outstanding was \$388.0 million and \$394.0 million at March 31, 2020 and December 31, 2019, respectively. The unused portion of the available borrowings under the Credit Facility were \$262.0 million and \$256.0 million at March 31, 2020 and December 31, 2019, respectively.

NOTE 7 - COMMITMENTS AND CONTINGENCIES

Environmental Matters

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

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

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

Put Option Related to Noble Acquisition

By acquiring 100% of the issued and outstanding securities of Samedan Royalty, LLC, now NAMP Holdings, LLC, on November 28, 2017 from Noble Energy US Holdings, LLC, the Partnership acquired a 100% interest in Comin-Temin, LLC, now NAMP GP, LLC ("Holdings"), Comin 1989 Partnership LLLP, now NAMP 1, LP ("Comin"), and Temin 1987 Partnership LLLP, now NAMP 2, LP ("Temin"). Pursuant to certain co-ownership agreements, various co-owners hold undivided beneficial ownership interests in 45.33% and 42.63% of the mineral interests held of record by Holdings and Temin, respectively as of March 31, 2020. Based on the terms of the co-ownership agreements, the co-owners each have an unconditional option to require Comin or Temin, as applicable, to purchase their beneficial ownership interest in the mineral interests held of record by Holdings or Temin, as applicable, at any time within 30 days of receiving such repurchase notice. The purchase price of the beneficial ownership interest shall be based on an evaluation performed by Comin or Temin, as applicable, in good faith. As of March 31, 2020, the Partnership had not received notice from any co-owners to exercise their repurchase option, and as such, no liability was recorded.

Litigation

From time to time, the Partnership is involved in legal actions and claims arising in the ordinary course of business. The Partnership believes existing claims as of March 31, 2020 will be resolved without material adverse effect on the Partnership's financial condition or operations.

NOTE 8 - INCENTIVE COMPENSATION

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

| | Three Months Ended March 31, | |
|---|-------------------------------------|------------------|
| | 2020 | 2019 |
| | (in thousands) | |
| Cash—short and long-term incentive plans | \$ 963 | \$ 1,772 |
| Equity-based compensation—restricted common units | 1,285 | 3,019 |
| Equity-based compensation—restricted performance units ¹ | (4,657) | 5,620 |
| Board of Directors incentive plan | 478 | 585 |
| Total incentive compensation expense | \$ (1,931) | \$ 10,996 |

¹ Compensation expense related to the restricted performance awards is determined using the measurement-date (i.e., the last day of each reporting period date) fair value of the Partnership's common units. Downward cost revisions recognized in the first quarter of 2020 are due to the decrease in the Partnership's common unit price period over period.

NOTE 9 - PREFERRED UNITS

Series B Cumulative Convertible Preferred Units

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

The Series B cumulative convertible preferred units are entitled to an annual distribution of 7%, payable on a quarterly basis in arrears. The Series B cumulative convertible preferred units may be converted by each holder at its option, in whole or in part, into common units on a one-for-one basis at the purchase price of \$20.3926, adjusted to give effect to any accrued but unpaid accumulated distributions on the applicable Series B cumulative convertible preferred units through the most recent declaration date. However, the Partnership shall not be obligated to honor any request for such conversion if such request does not involve an underlying value of common units of at least \$10.0 million based on the closing trading price of common units on the trading day immediately preceding the conversion notice date, or such lesser amount to the extent such exercise covers all of a holder's Series B cumulative convertible preferred units.

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

The Series B cumulative convertible preferred units had a carrying value of \$298.4 million, including accrued distributions of \$5.3 million, as of March 31, 2020 and December 31, 2019. The Series B cumulative convertible preferred units are classified as mezzanine equity on the consolidated balance sheets since certain provisions of redemption are outside the control of the Partnership.

NOTE 10 - EARNINGS PER UNIT

The Partnership applies the two-class method for purposes of calculating earnings per unit (“EPU”). The holders of the Partnership’s restricted common units have all the rights of a unitholder, including non-forfeitable distribution rights. As participating securities, the restricted common units are included in the calculation of basic earnings per unit. For the periods presented, the amount of earnings allocated to these participating units was not material.

Net income (loss) attributable to the Partnership is allocated to the Partnership’s general partner and the common and subordinated unitholders in proportion to their pro rata ownership after giving effect to distributions, if any, declared during the period.

The Partnership assesses the Series B cumulative convertible preferred units on an as-converted basis for the purpose of calculating diluted EPU. The Partnership’s restricted performance unit awards are contingently issuable units that are considered in the calculation of diluted EPU. The Partnership assesses the number of units that would be issuable, if any, under the terms of the arrangement if the end of the reporting period were the end of the contingency period.

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

| | Three Months Ended March 31, | |
|--|--|-----------------|
| | 2020 | 2019 |
| | (in thousands, except per unit amounts) | |
| NET INCOME (LOSS) | \$ 76,112 | \$ 9,017 |
| Distributions on Series B cumulative convertible preferred units | (5,250) | (5,250) |
| NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON AND SUBORDINATED UNITS | 70,862 | 3,767 |
| ALLOCATION OF NET INCOME (LOSS): | | |
| General partner interest | \$ — | \$ — |
| Common units | 70,862 | 1,905 |
| Subordinated units | — | 1,862 |
| | \$ 70,862 | \$ 3,767 |
| Weighted average common units outstanding: | | |
| Weighted average common units outstanding (basic) | 206,631 | 109,420 |
| Effect of dilutive securities | — | 615 |
| Weighted average common units outstanding (diluted) | 206,631 | 110,035 |
| Weighted average subordinated units outstanding: | | |
| Weighted average subordinated units outstanding (basic) | — | 96,329 |
| Effect of dilutive securities | — | — |
| Weighted average subordinated units outstanding (diluted) | — | 96,329 |
| NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON AND SUBORDINATED UNIT: | | |
| Per common unit (basic) | \$ 0.34 | \$ 0.02 |
| Per subordinated unit (basic) | — | 0.02 |
| Per common unit (diluted) | 0.34 | 0.02 |
| Per subordinated unit (diluted) | — | 0.02 |

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

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

| | Three Months Ended March 31, | |
|--|------------------------------|--------|
| | 2020 | 2019 |
| | (in thousands) | |
| Potentially dilutive securities (common units): | | |
| Series B cumulative convertible preferred units on an as-converted basis | 14,969 | 14,969 |

NOTE 11 - COMMON AND SUBORDINATED UNITS

Common and Subordinated Units

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

The holders of common units are and, prior to the end of the subordination period (as defined in the partnership agreement), the subordinated units were, entitled to participate in distributions and exercise the rights and privileges provided to limited partners holding common units and subordinated units, respectively, under the partnership agreement. The subordination period under the partnership agreement ended on the first business day after the Partnership earned and paid an aggregate amount of at least \$1.35 (the annualized minimum quarterly distribution applicable for quarterly periods ending March 31, 2019 and thereafter) multiplied by the total number of outstanding common and subordinated units for a period of four consecutive, non-overlapping quarters ending on or after March 31, 2019, and there were no outstanding arrearages on the common units. This test was met upon the payment of the distribution for the first quarter of 2019. Accordingly, each outstanding subordinated unit converted into one common unit on May 24, 2019 and the priority right of the common unitholders ceased to exist.

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

- *first*, to the holders of the Series B cumulative convertible preferred units in an amount equal to 7% per annum, subject to certain adjustments; and
- *second*, to the holders of common units.

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

| | Three Months Ended March 31, | |
|---|------------------------------|-----------|
| | 2020 | 2019 |
| DISTRIBUTIONS DECLARED AND PAID: | | |
| Per common unit | \$ 0.3000 | \$ 0.3700 |
| Per subordinated unit | — | 0.3700 |

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

Common Unit Repurchase Program

On November 5, 2018, the Board authorized the repurchase of up to \$75.0 million in common units. The repurchase program authorizes the Partnership to make repurchases on a discretionary basis as determined by management, subject to market conditions, applicable legal requirements, available liquidity, and other appropriate factors. The Partnership made no repurchases under this program for the three months ended March 31, 2020. As of March 31, 2020, the Partnership has repurchased \$4.2 million in common units under the repurchase program since inception. The repurchase program is funded from the Partnership's cash on hand or availability on the Credit Facility. Any repurchased units are canceled.

NOTE 12 - SUBSEQUENT EVENTS

On April 22, 2020, the Board approved a distribution for the three months ended March 31, 2020 of \$0.08 per common unit. Distributions will be payable on May 21, 2020 to unitholders of record at the close of business on May 14, 2020.

On May 4, 2020, the Partnership entered into a development agreement with affiliates of Aethon Energy ("Aethon") with respect to the Partnership's undeveloped Shelby Trough Haynesville and Bossier shale acreage in Angelina County, Texas. The agreement provides for minimum well commitments by Aethon in exchange for reduced royalty rates and exclusive access to the Partnership's mineral and leasehold acreage in the contract area. The agreement calls for a minimum of four wells to be drilled in the initial program year, which begins in the third quarter of 2020, increasing to a minimum of 15 wells per year beginning with the third program year.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our unaudited consolidated financial statements and notes thereto presented in this Quarterly Report on Form 10-Q, as well as our audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2019 ("2019 Annual Report on Form 10-K"). This discussion and analysis contains forward-looking statements that involve risks, uncertainties, and assumptions. Actual results may differ materially from those anticipated in these forward-looking statements as a result of a number of factors, including those set forth under "Cautionary Note Regarding Forward-Looking Statements" and "Part II, Item 1A. Risk Factors."

Cautionary Note Regarding Forward-Looking Statements

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

- our ability to execute our business strategies;
- the scope and duration of the COVID-19 pandemic and actions taken by governmental authorities and other parties in response to the pandemic;
- the volatility of realized oil and natural gas prices, including the sharp decline in oil prices that occurred in the first quarter of 2020;
- the level of production on our properties;
- the overall supply and demand for oil and natural gas, regional supply and demand factors, delays, or interruptions of production;
- our ability to replace our oil and natural gas reserves;
- our ability to identify, complete, and integrate acquisitions;
- general economic, business, or industry conditions, including slowdowns, domestically and internationally and volatility in the securities, capital or credit markets;
- competition in the oil and natural gas industry;
- the level of drilling activity by our operators particularly in areas such as the Shelby Trough where we have concentrated acreage positions;
- the ability of our operators to obtain capital or financing needed for development and exploration operations;
- title defects in the properties in which we invest;
- the availability or cost of rigs, equipment, raw materials, supplies, oilfield services, or personnel;
- restrictions on the use of water for hydraulic fracturing;
- the availability of pipeline capacity and transportation facilities;

- the ability of our operators to comply with applicable governmental laws and regulations and to obtain permits and governmental approvals;
- federal and state legislative and regulatory initiatives relating to hydraulic fracturing;
- future operating results;
- future cash flows and liquidity, including our ability to generate sufficient cash to pay quarterly distributions;
- exploration and development drilling prospects, inventories, projects, and programs;
- operating hazards faced by our operators;
- the ability of our operators to keep pace with technological advancements; 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 2019 Annual Report on Form 10-K and in this Quarterly Report on Form 10-Q.

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

Overview

We are one of the largest owners and managers of oil and natural gas mineral interests in the United States. Our principal business is maximizing the value of our existing portfolio of mineral and royalty assets through active management and expanding our asset base through acquisitions of additional mineral and royalty interests. We maximize value through marketing our mineral assets for lease, creatively structuring the terms on those leases to encourage and accelerate drilling activity, and selectively participating alongside our lessees on a working interest basis. We believe our large, diversified asset base and long-lived, non-cost-bearing mineral and royalty interests provide for stable to growing production and reserves over time, allowing the majority of generated cash flow to be distributed to unitholders.

As of March 31, 2020, our mineral and royalty interests were located in 41 states in the continental United States, including all of the major onshore producing basins. These non-cost-bearing interests include ownership in approximately 69,000 producing wells. We also own non-operated working interests, a significant portion of which are on our positions where we also have a mineral and royalty interest. We recognize oil and natural gas revenue from our mineral and royalty and non-operated working interests in producing wells when control of the oil and natural gas produced is transferred to the customer and collectability of the sales price is reasonably assured. Our other sources of revenue include mineral lease bonus and delay rentals, which are recognized as revenue according to the terms of the lease agreements.

Recent Developments

COVID-19 Pandemic and Commodity Prices

The COVID-19 pandemic has adversely affected the global economy, disrupted global supply chains and created significant volatility in the financial markets. In addition, the pandemic has resulted in travel restrictions, business closures and the institution of quarantining and other restrictions on movement in many communities. To protect the health and well-being of our workforce in the wake of COVID-19, we have implemented remote work arrangements for all employees. We do not expect these arrangements to impact our ability to maintain operations.

The impact of the COVID-19 pandemic and geopolitical events that increased the supply of low-priced oil have also negatively affected the oil and natural gas business environment, significantly reducing prices of oil, natural gas, and natural gas liquids ("NGLs"). While we use derivative instruments to partially mitigate the impact of commodity price volatility, our revenues and operating results depend significantly upon the prevailing prices for oil and natural gas. The current price environment has caused some of our operators' wells to become uneconomic, which has resulted, or may result in the future, in suspension of production from those wells or a significant reduction in or no royalty revenues from existing production. Some operators may also attempt to shut in producing wells and avoid lease termination or payment of shut-in royalties by claiming force majeure, if provided for in the applicable lease. Because these shut-ins have happened so recently, and no operator has, to our knowledge claimed force majeure, we have not been able to quantify their impact on our future revenues.

The current price environment also caused us to determine that certain depletable units consisting of mature oil producing properties were impaired. Therefore, we recognized impairment of oil and natural gas properties of \$51.0 million for three months ended March 31, 2020. Additionally, the borrowing base under the Credit Facility, which takes into consideration the estimated loan value of our oil and natural gas properties, was reduced from \$650.0 million to \$460.0 million, effective May 1, 2020. In a prolonged period of low commodity prices, we may be required to impair additional properties and the borrowing base under our credit facility could be further reduced. In light of the challenging business environment and uncertainty caused by the pandemic, the board of directors of our general partner (the "Board") also approved a reduction in the quarterly distribution for the first quarter of 2020 to increase the amount of retained free cash flow for debt reduction and balance sheet protection.

Shelby Trough Update

On May 4, 2020, we entered into a development agreement with affiliates of Aethon Energy ("Aethon") with respect to our undeveloped Shelby Trough Haynesville and Bossier shale acreage in Angelina County, Texas. The agreement provides for minimum well commitments by Aethon in exchange for reduced royalty rates and exclusive access to our mineral and leasehold acreage in the contract area. The agreement calls for a minimum of four wells to be drilled in the initial program year, which begins in the third quarter of 2020, increasing to a minimum of 15 wells per year beginning with the third program year.

Common Unit Repurchase Program

On November 5, 2018, the Board authorized the repurchase of up to \$75.0 million in common units. The repurchase program authorizes us to make repurchases on a discretionary basis as determined by management, subject to market conditions, applicable legal requirements, available liquidity, and other appropriate factors. All or a portion of any repurchases may be made under a Rule 10b5-1 plan, which would permit common units to be purchased when we might otherwise be precluded from doing so under applicable laws. The repurchase program does not obligate us to acquire any particular amount of common units and may be modified or suspended at any time and could be terminated prior to completion. We will periodically report the number of common units repurchased. We made no repurchases under this program for the three months ended March 31, 2020. As of March 31, 2020, we have repurchased \$4.2 million in common units under the repurchase program since inception. The repurchase program is funded from our cash on hand or availability under the Credit Facility. Any repurchased units are canceled.

Business Environment

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

COVID-19 Pandemic and Market Conditions

The COVID-19 pandemic and related economic repercussions have resulted in a significant reduction in demand for and prices of oil, natural gas and NGLs. The effect of this was amplified late in the quarter when the Organization of Petroleum Exporting Countries and its broader partners ("OPEC+") were unable to reach an agreement on production levels for oil, at which point Saudi Arabia and Russia initiated efforts to aggressively increase production. While OPEC+ agreed in April 2020 to cut production, downward pressure on commodity prices has remained and could continue for the foreseeable future. In addition, concerns over the saturation of storage capacity for oil has further depressed prices. We expect these market conditions to result in a decline in drilling activity as operators revise their capital budgets downward and adjust their operations, including shutting in currently producing wells, in response to lower commodity prices. Given the dynamic nature of these events, we cannot reasonably estimate the period of time that the COVID-19 pandemic and related market conditions will persist.

Commodity Prices and Demand

Oil and natural gas prices have been historically volatile based upon the dynamics of supply and demand. To manage the variability in cash flows associated with the projected sale of our oil and natural gas production, we use various derivative instruments, which have recently consisted of fixed-price swap contracts and costless collar contracts.

The following table reflects commodity prices as of each date presented:

| Benchmark Prices¹ | April 24, 2020 | March 31, 2020 | March 31, 2019 |
|---------------------------------------|-----------------------|-----------------------|-----------------------|
| WTI spot oil price (\$/Bbl) | \$ 15.99 | \$ 20.51 | \$ 60.19 |
| Henry Hub spot natural gas (\$/MMBtu) | \$ 1.81 | \$ 1.71 | \$ 2.73 |

¹ Source: EIA

Rig Count

As we are not the operator of record on any producing properties, drilling on our acreage is dependent upon the exploration and production companies that lease our acreage. In addition to drilling plans that we seek from our operators, we also monitor rig counts in an effort to identify existing and future leasing and drilling activity on our acreage.

The following table shows the rig count as of each date presented:

| U.S. Rotary Rig Count¹ | April 24, 2020 | March 31, 2020 | March 31, 2019 |
|--|-----------------------|-----------------------|-----------------------|
| Oil | 378 | 624 | 816 |
| Natural gas | 85 | 102 | 190 |
| Other | 2 | 2 | — |
| Total | 465 | 728 | 1,006 |

¹ Source: Baker Hughes Incorporated

Natural Gas Storage

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

Historically, natural gas supply and demand fluctuates on a seasonal basis. From April to October, when the weather is warmer and natural gas demand is lower, natural gas storage levels generally increase. From November to March, storage levels typically decline as utility companies draw natural gas from storage to meet increased heating demand due to colder weather. In order to maintain sufficient storage levels for increased seasonal demand, a portion of natural gas production during the summer months must be used for storage injection. The portion of production used for storage varies from year to year depending on the demand from the previous winter and the demand for electricity used for cooling during the summer months. The EIA estimates that natural gas inventories concluded the withdrawal season on March 31, 2020 at almost 2.0 Tcf, or 17% higher than the previous five-year average.

The following table shows natural gas storage volumes by region as of each date presented:

| Region¹ | April 24, 2020 | March 31, 2020 | March 31, 2019 |
|---------------------------|-----------------------|-----------------------|-----------------------|
| East | 405 | 382 | 210 |
| Midwest | 506 | 476 | 241 |
| Mountain | 103 | 92 | 64 |
| Pacific | 218 | 197 | 113 |
| South Central | 979 | 840 | 502 |
| Total | 2,211 | 1,987 | 1,130 |

¹ Source: EIA

How We Evaluate Our Operations

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

- volumes of oil and natural gas produced;
- commodity prices including the effect of derivative instruments; and
- Adjusted EBITDA and Distributable cash flow.

Volumes of Oil and Natural Gas Produced

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

Commodity Prices

Factors Affecting the Sales Price of Oil and Natural Gas

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

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

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

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

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

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

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

Hedging

We enter into derivative instruments to partially mitigate the impact of commodity price volatility on our cash generated from operations. From time to time, such instruments may include variable-to-fixed-price swaps, fixed-price contracts, costless collars, and other contractual arrangements. The impact of these derivative instruments could affect the amount of revenue we ultimately realize.

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

We may employ contractual arrangements other than fixed-price swap contracts and costless collar contracts in the future to mitigate the impact of price fluctuations. If commodity prices decline in the future, our hedging contracts will partially mitigate the effect of lower prices on our future revenue. Our open oil and natural gas derivative contracts as of March 31, 2020 are detailed in Note 4 - Commodity Derivative Financial Instruments to our unaudited consolidated financial statements included elsewhere in this Quarterly Report.

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

We are allowed to hedge up to 90% of such volumes for the first 24 months, 70% for months 25 through 36, and 50% for months 37 through 48. As of March 31, 2020, we have hedged 91% of our available oil and condensate hedge volumes and 75% of our available natural gas hedge volumes for 2020.

We intend to continuously monitor the production from our assets and the commodity price environment, and will, from time to time, add additional hedges within the percentages described above related to such production for the following 12 to 30 months. We do not enter into derivative instruments for speculative purposes.

Non-GAAP Financial Measures

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

We define Adjusted EBITDA as net income (loss) before interest expense, income taxes, and depreciation, depletion, and amortization adjusted for impairment of oil and natural gas properties, accretion of asset retirement obligations, unrealized gains and losses on commodity derivative instruments, and non-cash equity-based compensation. We define Distributable cash flow as Adjusted EBITDA plus or minus amounts for certain non-cash operating activities, estimated replacement capital expenditures during the subordination period, cash interest expense, distributions to preferred unitholders, and restructuring charges.

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

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

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

| | Three Months Ended March 31, | |
|--|-------------------------------------|-------------|
| | 2020 | 2019 |
| (in thousands) | | |
| Net income (loss) | \$ 76,112 | \$ 9,017 |
| Adjustments to reconcile to Adjusted EBITDA: | | |
| Depreciation, depletion, and amortization | 23,182 | 27,833 |
| Impairment of oil and natural gas properties | 51,031 | — |
| Interest expense | 4,427 | 5,525 |
| Income tax expense (benefit) | 36 | 131 |
| Accretion of asset retirement obligations | 272 | 277 |
| Equity-based compensation | (2,894) | 9,223 |
| Unrealized (gain) loss on commodity derivative instruments | (81,057) | 42,926 |
| Adjusted EBITDA | 71,109 | 94,932 |
| Adjustments to reconcile to Distributable cash flow: | | |
| Change in deferred revenue | (302) | (304) |
| Cash interest expense | (4,168) | (5,269) |
| Estimated replacement capital expenditures ¹ | — | (2,750) |
| Preferred unit distributions | (5,250) | (5,250) |
| Restructuring charges ² | 4,815 | — |
| Distributable cash flow | \$ 66,204 | \$ 81,359 |

¹ The Board established a replacement capital expenditure estimate of \$11.0 million for the period of April 1, 2018 to March 31, 2019. Due to the expiration of the subordination period, we do not intend to establish a replacement capital expenditure estimate for periods subsequent to March 31, 2019.

² Restructuring charges include non-recurring costs associated with broad workforce reductions in the first quarter of 2020.

Results of Operations

Three Months Ended March 31, 2020 Compared to Three Months Ended March 31, 2019

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

| | Three Months Ended March 31, | | | |
|--|------------------------------|-----------|------------|-----------------|
| | 2020 | 2019 | Variance | |
| (Dollars in thousands, except for realized prices) | | | | |
| Production: | | | | |
| Oil and condensate (MBbls) | 1,163 | 1,108 | 55 | 5.0 % |
| Natural gas (MMcf) ¹ | 18,612 | 18,615 | (3) | — % |
| Equivalents (MBoe) | 4,265 | 4,211 | 54 | 1.3 % |
| Equivalents/day (MBoe) | 46.9 | 46.8 | 0.1 | 0.2 % |
| Realized prices, without derivatives: | | | | |
| Oil and condensate (\$/Bbl) | \$ 44.79 | \$ 52.08 | \$ (7.29) | (14.0)% |
| Natural gas (\$/Mcf) ¹ | 1.97 | 3.31 | (1.34) | (40.5)% |
| Equivalents (\$/Boe) | \$ 20.81 | \$ 28.34 | \$ (7.53) | (26.6)% |
| Revenue: | | | | |
| Oil and condensate sales | \$ 52,093 | \$ 57,704 | \$ (5,611) | (9.7)% |
| Natural gas and natural gas liquids sales ¹ | 36,642 | 61,640 | (24,998) | (40.6)% |
| Lease bonus and other income | 4,308 | 5,645 | (1,337) | (23.7)% |
| Revenue from contracts with customers | 93,043 | 124,989 | (31,946) | (25.6)% |
| Gain (loss) on commodity derivative instruments | 90,011 | (41,183) | 131,194 | NM ² |
| Total revenue | \$ 183,054 | \$ 83,806 | \$ 99,248 | 118.4 % |
| Operating expenses: | | | | |
| Lease operating expense | \$ 3,827 | \$ 5,292 | \$ (1,465) | (27.7)% |
| Production costs and ad valorem taxes | 12,376 | 14,592 | (2,216) | (15.2)% |
| Exploration expense | 1 | 4 | (3) | (75.0)% |
| Depreciation, depletion, and amortization | 23,182 | 27,833 | (4,651) | (16.7)% |
| Impairment of oil and natural gas properties | 51,031 | — | 51,031 | NM ² |
| General and administrative | 11,856 | 21,214 | (9,358) | (44.1)% |
| Other expense: | | | | |
| Interest expense | 4,427 | 5,525 | (1,098) | (19.9)% |

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

² Not meaningful.

Revenue

Total revenue for the quarter ended March 31, 2020 increased compared to the quarter ended March 31, 2019. The increase in total revenue from the corresponding period is primarily due to a gain on our commodity derivative instruments in the first quarter of 2020, compared to a loss in the first quarter of 2019. The overall increase in total revenue was partially offset by a decrease in oil and condensate sales and natural gas and NGL sales as a result of lower realized commodity prices and a decrease in lease bonus and other income.

Oil and condensate sales. Oil and condensate sales decreased for the quarter ended March 31, 2020 as compared to the corresponding period in 2019 due to lower realized commodity prices, partially offset by higher production volumes. Our

mineral and royalty interest oil and condensate volumes increased 4% in the first quarter of 2020 relative to the corresponding period in 2019, primarily driven by production increases in the Permian Basin. Our mineral and royalty interest oil and condensate volumes accounted for 92% of total oil and condensate volumes for the quarters ended March 31, 2020 and 2019.

Natural gas and natural gas liquids sales. Natural gas and NGL sales decreased for the quarter ended March 31, 2020 as compared to the corresponding prior period due to lower realized commodity prices. Mineral and royalty interest production accounted for 73% and 64% of our natural gas volumes for the quarters ended March 31, 2020 and 2019, respectively.

Gain (loss) on commodity derivative instruments. During the first quarter of 2020, we recognized a gain from our commodity derivative instruments compared to a loss in the same period in 2019. Cash settlements we receive represent realized gains, while cash settlements we pay represent realized losses related to our commodity derivative instruments. In addition to cash settlements, we also recognize fair value changes on our commodity derivative instruments in each reporting period. The changes in fair value result from new positions and settlements that may occur during each reporting period, as well as the relationships between contract prices and the associated forward curves. For the three months ended March 31, 2020, we recognized \$9.0 million of realized gains and \$81.1 million of unrealized gains from our oil and natural gas commodity contracts, compared to \$1.7 million of realized gains and \$42.9 million of unrealized losses in the same period in 2019. The unrealized gains on our commodity contracts during the first quarter of 2020 and the unrealized losses in the same period in 2019 were primarily driven by changes in the forward commodity price curves for oil during each period.

Lease bonus and other income. When we lease our mineral interests, we generally receive an upfront cash payment, or a lease bonus. Lease bonus revenue can vary substantively between periods because it is derived from individual transactions with operators, some of which may be significant. Lease bonus and other income for the first quarter of 2020 was lower than the same period in 2019. Leasing activity in the Permian Basin, Green River Basin, and Bakken/Three Forks made up the majority of lease bonus revenue in the first quarter of 2020, while a substantial portion of first quarter 2019 activity came from the Permian Basin, Woodbine, and Haynesville Shale.

Operating Expenses

Lease operating expense. Lease operating expense includes recurring expenses associated with our non-operated working interests necessary to produce hydrocarbons from our oil and natural gas wells, as well as certain nonrecurring expenses, such as well repairs. Lease operating expense decreased for the quarter ended March 31, 2020 as compared to the same period in 2019, primarily due to lower nonrecurring service-related expenses, including workovers, on wells in which we own a non-operating working interest.

Production costs and ad valorem taxes. Production taxes include statutory amounts deducted from our production revenues by various state taxing entities. Depending on the regulations of the states where the production originates, these taxes may be based on a percentage of the realized value or a fixed amount per production unit. This category also includes the costs to process and transport our production to applicable sales points. Ad valorem taxes are jurisdictional taxes levied on the value of oil and natural gas minerals and reserves. Rates, methods of calculating property values, and timing of payments vary between taxing authorities. For the quarter ended March 31, 2020, production costs and ad valorem taxes decreased as compared to the quarter ended March 31, 2019, primarily as a result of lower commodity prices.

Exploration expense. Exploration expense typically consists of dry-hole expenses, delay rentals, and geological and geophysical costs, including seismic costs, and is expensed as incurred under the successful efforts method of accounting. Exploration expense was minimal for each of the three months ended March 31, 2020 and 2019.

Depreciation, depletion, and amortization. Depletion is the amount of cost basis of oil and natural gas properties attributable to the volume of hydrocarbons extracted during a period, calculated on a units-of-production basis. Estimates of proved developed producing reserves are a major component of the calculation of depletion. We adjust our depletion rates semi-annually based upon mid-year and year-end reserve reports, except when circumstances indicate that there has been a significant change in reserves or costs. Depreciation, depletion, and amortization decreased for the quarter ended March 31, 2020 as compared to the same period in 2019, primarily due to a reduction in cost basis with a lower corresponding reduction in proved developed producing reserve quantities. The reduction in cost basis is primarily due to depreciation, depletion, and amortization recorded during the prior twelve months.

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 \$51.0 million for the quarter ended March 31, 2020 primarily

due to declines in future expected realizable net cash flows as a result of lower commodity prices as of March 31, 2020. There were no impairments for the quarter ended March 31, 2019.

General and administrative. General and administrative expenses are costs not directly associated with the production of oil and natural gas and include expenses such as the cost of employee salaries and related benefits, office expenses, and fees for professional services. For the quarter ended March 31, 2020, general and administrative expenses decreased as compared to the same period in 2019, primarily due to lower costs associated with our incentive compensation plans. This change was driven by \$4.7 million of downward cost revisions recognized in the first quarter of 2020 for performance-based incentive awards due to the decrease in our common unit price period over period compared with \$5.6 million of costs recognized for performance-based incentive awards in the first quarter of 2019. Incentive compensation costs in the first quarter of 2019 also included incentive compensation awarded in connection with our initial public offering. The overall decrease was partially offset by \$4.8 million of restructuring charges associated with broad workforce reductions in the first quarter of 2020.

Interest expense. Interest expense was lower in the first quarter of 2020 relative to the corresponding period in 2019, due to lower interest rates and lower average outstanding borrowings under our Credit Facility.

Liquidity and Capital Resources

Overview

Our primary sources of liquidity are cash generated from operations, borrowings under our Credit Facility, and proceeds from the issuance of equity and debt. Our primary uses of cash are for distributions to our unitholders, reducing outstanding borrowings under our Credit Facility, and for investing in our business, specifically the acquisition of mineral and royalty interests and our selective participation on a non-operated working interest basis in the development of our oil and natural gas properties. As of March 31, 2020, we had outstanding borrowings of \$388.0 million under the Credit Facility, and on May 1, 2020, the borrowing base under our Credit Facility was reduced to \$460.0 million.

The Board has adopted a policy pursuant to which, at a minimum, distributions will be paid on each common unit for each quarter to the extent we have sufficient cash generated from our operations after establishment of cash reserves, if any, and after we have made the required distributions to the holders of our outstanding preferred units. However, we do not have a legal or contractual obligation to pay distributions on our common units quarterly or on any other basis, and there is no guarantee that we will pay distributions to our common unitholders in any quarter. The Board may change the foregoing distribution policy at any time and from time to time. In light of the challenging business environment and uncertainty caused by the pandemic, the Board approved a reduction in the quarterly distribution for the first quarter of 2020 to increase the amount of retained free cash flow for debt reduction and balance sheet protection. If our borrowings exceed our borrowing base, our ability to pay cash distributions to our unitholders will be limited.

We intend to finance our future acquisitions with cash generated from operations, borrowings from our Credit Facility, and proceeds from any future issuances of equity and debt. Over the long-term, we intend to finance our working interest capital needs with our executed farmout agreements and internally-generated cash flows, although at times we may fund a portion of these expenditures through other financing sources such as borrowings under our Credit Facility. Replacement capital expenditures are expenditures necessary to replace our existing oil and natural gas reserves or otherwise maintain our asset base over the long-term. The Board established a replacement capital expenditure estimate of \$11.0 million for the period of April 1, 2018 to March 31, 2019. Due to the expiration of the subordination period, we do not intend to establish a replacement capital expenditure estimate for periods subsequent to March 31, 2019.

Cash Flows

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

| | Three Months Ended March 31, | | |
|---|-------------------------------------|-------------|---------------|
| | 2020 | 2019 | Change |
| | (in thousands) | | |
| Cash flows provided by operating activities | \$ 71,450 | \$ 90,174 | \$ (18,724) |
| Cash flows provided by (used in) investing activities | 1,391 | (24,379) | 25,770 |
| Cash flows used in financing activities | (77,920) | (66,962) | (10,958) |

Operating Activities. Our operating cash flows are dependent, in large part, on our production, realized commodity prices, derivative settlements, lease bonus revenue, and operating expenses. Cash flows provided by operating activities decreased in the first quarter of 2020 as compared to the same period of 2019. The decrease was primarily due to decreased oil and condensate sales and natural gas and NGL sales driven by lower realized commodity prices for the three months ended March 31, 2020 compared to the same period of 2019. The overall decrease was partially offset by higher net cash received on settlement of commodity derivative instruments.

Investing Activities. Net cash was provided by investing activities in the first quarter of 2020 as compared to net cash used in investing activities in the same period of 2019. The change was primarily due to reduced oil and natural gas property acquisitions and expenditures and the receipt of proceeds from the sale of oil and natural gas properties in the first quarter of 2020.

Financing Activities. Cash flows used in financing activities increased in the first quarter of 2020 as compared to the same period of 2019. The increase was primarily due to net repayments under our Credit Facility in the first quarter of 2020 as compared to net borrowings in the first quarter of 2019. The overall increase was partially offset by lower distributions to common and subordinated unitholders and decreased repurchases of common units.

Development Capital Expenditures

Our 2020 total development capital expenditure budget associated with our non-operated working interests is expected to be approximately \$5.0 million, net of farmout reimbursements, of which a nominal amount has been invested in the three months ended March 31, 2020. The majority of this capital will be spent for workovers on existing wells in which we own a working interest.

Credit Facility

Pursuant to our \$1.0 billion senior secured revolving credit agreement, as amended (the "Credit Facility"), the commitment of the lenders equals the lesser of the aggregate maximum credit amounts of the lenders and the borrowing base, which is determined based on the lenders' estimated value of our oil and natural gas properties. Borrowings under the Credit Facility may be used for the acquisition of properties, cash distributions, and other general corporate purposes. Our Credit Facility terminates on November 1, 2022. As of March 31, 2020, we had outstanding borrowings of \$388.0 million at a weighted-average interest rate of 3.22%.

The borrowing base is redetermined semi-annually, typically in April and October of each year, by the administrative agent, taking into consideration the estimated loan value of our oil and natural gas properties consistent with the administrative agent's normal lending criteria. The administrative agent's proposed redetermined borrowing base must be approved by all lenders to increase our existing borrowing base, and by two-thirds of the lenders to maintain or decrease our existing borrowing base. In addition, we and the lenders (at the direction of two-thirds of the lenders) each have discretion to request a borrowing base redetermination one time between scheduled redeterminations. We also have the right to request a redetermination following acquisition of oil and natural gas properties in excess of 10% of the value of the borrowing base immediately prior to such acquisition. Effective October 23, 2019 the borrowing base redetermination reduced the borrowing base from \$675.0 million to \$650.0 million and, effective May 1, 2020, the borrowing base was further reduced to \$460.0 million.

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

We are obligated to pay a quarterly commitment fee ranging from a 0.375% to 0.500% annualized rate on the unused portion of the borrowing base, depending on the amount of the borrowings outstanding in relation to the borrowing base. Principal may be optionally repaid from time to time without premium or penalty, other than customary LIBOR breakage, and is required to be paid (a) if the amount outstanding exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise, in some cases subject to a cure period, or (b) at the maturity date. Our Credit Facility is secured by substantially all of our oil and natural gas production and assets.

Our credit agreement contains various affirmative, negative, and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates, and entering into certain derivative agreements, as well as require the maintenance of

certain financial ratios. The credit agreement contains two financial covenants: total debt to EBITDAX of 3.5:1.0 or less and a current ratio of 1.0:1.0 or greater as defined in the credit agreement. Distributions are not permitted if there is a default under the credit agreement (including the failure to satisfy one of the financial covenants) or during any time that our borrowing base is lower than the loans outstanding under the credit agreement. The lenders have the right to accelerate all of the indebtedness under the credit agreement upon the occurrence and during the continuance of any event of default, and the credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy, and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods. As of March 31, 2020, we were in compliance with all debt covenants.

On July 27, 2017, the U.K. Financial Conduct Authority announced that it intends to stop persuading or compelling banks to submit LIBOR rates after 2021. Our Credit Facility includes provisions to determine a replacement rate for LIBOR if necessary during its term, which require that we and our lenders agree upon a replacement rate based on the then-prevailing market convention for similar agreements. We currently do not expect the transition from LIBOR to have a material impact on us. However, if clear market standards and replacement methodologies have not developed as of the time LIBOR becomes unavailable, we may have difficulty reaching agreement on acceptable replacement rates under our Credit Facility. In the event that we do not reach agreement on an acceptable replacement rate for LIBOR, outstanding borrowings under the Credit Facility would revert to a floating rate equal to the alternative base rate (which, as of the time that LIBOR becomes unavailable, is equal to the greater of the Prime Rate and the Federal Funds effective rate plus 0.50%) plus the applicable margin for the alternative base rate which ranges between 0.75% to 1.75%. If we are unable to negotiate replacement rates on favorable terms, it could have a material adverse effect on our financial condition, results of operations, and cash distributions to unitholders.

Contractual Obligations

As of March 31, 2020, there have been no material changes to our contractual obligations previously disclosed in our 2019 Annual Report on Form 10-K.

Off-Balance Sheet Arrangements

As of March 31, 2020, we did not have any material off-balance sheet arrangements.

Critical Accounting Policies and Related Estimates

As of March 31, 2020, there have been no significant changes to our critical accounting policies and related estimates previously disclosed in our 2019 Annual Report on Form 10-K.

New and Revised Financial Accounting Standards

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

Our major market risk exposure is the pricing of oil, natural gas, and NGLs produced by our operators. Realized prices are primarily driven by the prevailing global prices for oil and prices for natural gas and NGLs in the United States. Prices for oil, natural gas, and NGLs have been historically volatile, and we expect this unpredictability to continue in the future. The prices that our operators receive for production depend on many factors outside of our or their control. To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we use commodity derivative instruments to reduce our exposure to price volatility of oil and natural gas. The counterparties to the contracts are unrelated third parties. The contracts settle monthly in cash based on a designated floating price. The designated floating price is based on the NYMEX benchmark for oil and natural gas. We have not designated any of our contracts as fair value or cash flow hedges. Accordingly, the changes in fair value of the contracts are included in net income in the period of the change. See Note 4 - Commodity Derivative Financial Instruments and Note 5 - Fair Value Measurements to the unaudited interim consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for additional information.

To estimate the effect lower prices would have on our reserves, we reduced the SEC commodity pricing for the three months ended March 31, 2020 by 10%. This results in an approximate 2.5% reduction of proved reserve volumes as compared to the unadjusted March 31, 2020 SEC pricing scenario.

Counterparty and Customer Credit Risk

Our derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require our counterparties to our derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as we deem appropriate. This evaluation includes reviewing a counterparty's credit rating and latest financial information. As of March 31, 2020, we had eight counterparties, all of which were rated Baa1 or better by Moody's and are lenders under our Credit Facility.

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

Interest Rate Risk

We have exposure to changes in interest rates on our indebtedness. As of March 31, 2020, we had \$388.0 million of outstanding borrowings under our Credit Facility, bearing interest at a weighted-average interest rate of 3.22%. 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 \$1.0 million for the three months ended March 31, 2020, assuming that our indebtedness remained constant throughout the period. We may use certain derivative instruments to hedge our exposure to variable interest rates in the future, but we do not currently have any interest rate hedges in place.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (the "Exchange Act"), we have evaluated, under the supervision and with the participation of management of our general partner, including our general partner's principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report on Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our general partner's principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our general partner's principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of March 31, 2020.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended March 31, 2020 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

In addition to the other information set forth in this report, readers should carefully consider the risks under the heading “Risk Factors” in our 2019 Annual Report on Form 10-K. Except to the extent updated below, there has been no material change in our risk factors from those described in our 2019 Annual Report on Form 10-K. These risks, as updated below, are not the only risks that we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may materially adversely affect our business, financial condition or results of operations.

Risks Related to our Business

The COVID-19 pandemic and the significant decline in commodity prices in the first quarter of 2020 has adversely affected our business, and the ultimate effect on our financial condition, results of operations, and cash distributions to unitholders will depend on future developments, which are highly uncertain and cannot be predicted.

The COVID-19 pandemic has adversely affected the global economy, disrupted global supply chains and created significant volatility in the financial markets. In addition, the pandemic has resulted in travel restrictions, business closures and the institution of quarantining and other restrictions on movement in many communities. As a result, there has been a significant reduction in demand for and prices of oil, natural gas and natural gas liquids (“NGLs”). This has been amplified due to the announcement by Saudi Arabia of a significant increase in its maximum oil production capacity as well as the announcement by Russia that previously agreed upon oil production cuts between members of the Organization of the Petroleum Exporting Countries and its broader partners (“OPEC+”) would expire on April 1, 2020, and the ensuing expiration thereof. On April 12, 2020, members of OPEC+ agreed to certain production cuts; however, these cuts are not expected to be enough to offset near-term demand loss attributable to the COVID-19 pandemic. In addition, concerns over the saturation of storage capacity for oil has further depressed prices.

The impact of the COVID-19 pandemic and geopolitical events that increased the supply of low-priced oil have also negatively affected the oil and natural gas business environment, significantly reducing prices of oil, natural gas and NGLs. While we use derivative instruments to partially mitigate the impact of commodity price volatility, our revenues and operating results depend significantly upon the prevailing prices for oil and natural gas. The current price environment has caused some of our operators’ wells to become uneconomic, which has resulted, or may result in the future, in suspension of production from those wells or a significant reduction in or no royalty revenues from existing production. Some operators may also attempt to shut in producing wells and avoid lease termination or payment of shut-in royalties by claiming force majeure, if provided for in the applicable lease. Because these shut-ins have happened so recently, and no operator has, to our knowledge, claimed force majeure, we have not been able to quantify their impact on our future revenues.

The current price environment also caused us to determine that certain depletable units consisting of mature oil producing properties were impaired. Therefore, we recognized impairment of oil and natural gas properties of \$51.0 million for three months ended March 31, 2020. Additionally, the borrowing base under the Credit Facility, which takes into consideration the estimated loan value of our oil and natural gas properties, was reduced from \$650.0 million to \$460.0 million, effective May 1, 2020. In a prolonged period of low commodity prices, we may be required to impair additional properties and the borrowing base under our credit facility could be further reduced. In light of the challenging business environment and uncertainty caused by the pandemic, the board of directors of our general partner (the “Board”) also approved a reduction in the quarterly distribution for the first quarter of 2020 to increase the amount of retained free cash flow for debt reduction and balance sheet protection.

We enter into derivative instruments to partially mitigate the impact of commodity price volatility on our cash generated from operations. Any declines in production or production forecasts as a result of low commodity prices in light of COVID-19 pandemic and global oversupply could limit our ability to hedge future volumes.

The extent to which the COVID-19 pandemic adversely affects our business, results of operations, and financial condition will depend on future developments, which are highly uncertain and cannot be predicted, including the scope and duration of the pandemic and actions taken by governmental authorities and other third parties in response to the pandemic.

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

Recent Sales of Unregistered Securities

None.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table sets forth our purchases of our common units for each month during the three months ended March 31, 2020:

| Purchases of Common Units | | | | | |
|--------------------------------|---|-----------------------------|--|----|---|
| Period | Total Number of Common Units Purchased ¹ | Average Price Paid Per Unit | Total Number of Common Units Purchased as Part of Publicly Announced Plans or Programs | | Maximum Dollar Value of Common Units That May Yet Be Purchased Under the Plans or Programs ² |
| January 1 - January 31, 2020 | 170,622 | \$ 13.30 | — | \$ | 70,819,075 |
| February 1 - February 29, 2020 | 227,559 | 8.93 | — | | 70,819,075 |
| March 1 - March 31, 2020 | 105,174 | 6.98 | — | | 70,819,075 |

¹ Consists of units withheld to satisfy tax withholding obligations upon the vesting of certain restricted common units held by our executive officers and certain other employees.

² On November 5, 2018, the Board authorized the repurchase of up to \$75.0 million in common units. The repurchase program authorizes us to make repurchases on a discretionary basis as determined by management, subject to market conditions, applicable legal requirements, available liquidity, and other appropriate factors. All or a portion of any repurchases may be made under a Rule 10b5-1 plan, which would permit common units to be repurchased when we might otherwise be precluded from doing so under insider trading laws. The repurchase program does not obligate us to acquire any particular amount of common units and may be modified or suspended at any time and could be terminated prior to completion.

Item 5. Other Information

Item 1.01 Entry Into a Material Definitive Agreement

On May 1, 2020, Black Stone Minerals Company, L.P., as borrower (the “Borrower”) under that certain Fourth Amended and Restated Credit Agreement, dated as of November 1, 2017, by and among the Borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto (the “Credit Agreement”), together with Black Stone Minerals, L.P. (the “Partnership”) entered into the Third Amendment to Fourth Amended and Restated Credit Agreement (the “Third Amendment”). The Third Amendment principally modifies the Credit Agreement to (i) add anti-cash hoarding provisions and (ii) determine the Borrowing Base (as defined in the Credit Agreement) to be \$460.0 million until such time as it is redetermined in accordance with the terms of the Credit Agreement.

Item 2.03 Creation of a Direct Financial Obligation or an Obligation under an Off-Balance Sheet Arrangement of a Registrant

The description of the Third Amendment above under Item 1.01 is incorporated in this Item 2.03 by reference.

Item 6. Exhibits

| <u>Exhibit Number</u> | <u>Description</u> |
|-----------------------|---|
| 3.1 | Certificate of Limited Partnership of Black Stone Minerals, L.P. (incorporated herein by reference to Exhibit 3.1 to Black Stone Minerals, L.P.'s Registration Statement on Form S-1 filed on March 19, 2015 (SEC File No. 333-202875)). |
| 3.2 | Certificate of Amendment to Certificate of Limited Partnership of Black Stone Minerals, L.P. (incorporated herein by reference to Exhibit 3.2 to Black Stone Minerals, L.P.'s Registration Statement on Form S-1 filed on March 19, 2015 (SEC File No. 333-202875)). |
| 3.3 | First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated May 6, 2015, by and among Black Stone Minerals GP, L.L.C. and Black Stone Minerals Company, L.P., (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on May 6, 2015 (SEC File No. 001-37362)). |
| 3.4 | Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated as of April 15, 2016 (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on April 19, 2016 (SEC File No. 001-37362)). |
| 3.5 | Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated as of November 28, 2017 (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on November 29, 2017 (SEC File No. 001-37362)). |
| 3.6 | Amendment No. 3 to First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated as of December 11, 2017 (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on December 12, 2017 (SEC File No. 001-37362)). |
| 3.7 | Amendment No. 4 to First Amended and Restated Agreement of Limited Partnership of the Black Stone Minerals, L.P., dated as of April 22, 2020 (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on April 24, 2020 (SEC File No. 001-37362)). |
| 4.1 | Registration Rights Agreement, dated as of November 28, 2017, by and between Black Stone Minerals, L.P. and Mineral Royalties One, L.L.C. (incorporated herein by reference to Exhibit 4.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on November 29, 2017 (SEC File No. 001-37362)). |
| 10.1 | Separation and Consulting Agreement and General Release of Claims, dated as of March 6, 2020, by and among Holbrook F. Dorn, Black Stone Natural Resources Management Company, and Black Stone Minerals GP, L.L.C. (incorporated herein by reference to Exhibit 10.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on March 12, 2020 (SEC File No. 001-37362)) |
| 10.2 | Separation and Consulting Agreement and General Release of Claims, dated as of March 6, 2020, by and among Brock Morris, Black Stone Natural Resources Management Company, and Black Stone Minerals GP, L.L.C. (incorporated herein by reference to Exhibit 10.2 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on March 12, 2020 (SEC File No. 001-37362)) |
| 10.3* | Third Amendment to Fourth Amended and Restated Credit Agreement among Black Stone Minerals Company, L.P., as Borrower, Black Stone Minerals, L.P., as Parent MLP, Wells Fargo Bank, National Association, as Administrative Agent, and a syndicate of lenders dated as of May 1, 2020 |
| 31.1* | Certification of Chief Executive Officer of Black Stone Minerals, L.P. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2* | Certification of Chief Financial Officer of Black Stone Minerals, L.P. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32.1* | Certification of Chief Executive Officer and Chief Financial Officer of Black Stone Minerals, L.P. pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101.INS* | Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document. |
| 101.SCH* | Inline XBRL Schema Document |
| 101.CAL* | Inline XBRL Calculation Linkbase Document |
| 101.LAB* | Inline XBRL Label Linkbase Document |
| 101.PRE* | Inline XBRL Presentation Linkbase Document |
| 101.DEF* | Inline XBRL Definition Linkbase Document |
| 104* | Cover Page Interactive Data File - the cover page iXBRL tags are embedded within the Inline XBRL document. |

* Filed or furnished herewith.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BLACK STONE MINERALS, L.P.

By: Black Stone Minerals GP, L.L.C.,
its general partner

Date: May 5, 2020

By: /s/ Thomas L. Carter, Jr.

Thomas L. Carter, Jr.
Chief Executive Officer and Chairman
(Principal Executive Officer)

Date: May 5, 2020

By: /s/ Jeffrey P. Wood

Jeffrey P. Wood
President and Chief Financial Officer
(Principal Financial Officer)

**THIRD AMENDMENT TO FOURTH AMENDED
AND RESTATED CREDIT AGREEMENT**

THIS THIRD AMENDMENT TO FOURTH AMENDED AND RESTATED CREDIT AGREEMENT (this "Amendment") dated as of May 1, 2020, is among: BLACK STONE MINERALS COMPANY, L.P., a Delaware limited partnership, as Borrower; BLACK STONE MINERALS, L.P., a Delaware limited partnership, as Parent MLP; the Lenders party hereto; and WELLS FARGO BANK, NATIONAL ASSOCIATION, as Administrative Agent. Capitalized terms used herein but not otherwise defined herein have the meaning given such terms in the Credit Agreement.

RECITALS

Borrower, Parent MLP, Administrative Agent and Lenders are parties to that certain Fourth Amended and Restated Credit Agreement dated as of November 1, 2017, as amended by the First Amendment to Fourth Amended and Restated Credit Agreement dated as of February 7, 2018 and Second Amendment to Fourth Amended and Restated Credit Agreement dated as of October 31, 2018 (as amended, modified or supplemented to date, the "Credit Agreement").

Section 1. Amendments to Credit Agreement.

1.1 Certain Defined Terms. Section 1.02 of the Credit Agreement is hereby amended by adding the following defined terms in proper alphabetical order:

"Consolidated Cash Balance" means, at any time, the aggregate amount of cash, cash equivalents, marketable securities, treasury bonds and bills, certificates of deposit, investments in money market funds and commercial paper, in each case, held or owned by (whether directly or indirectly), credited to the account of, or otherwise reflected as an asset on the balance sheet of, the Parent MLP and its Consolidated Subsidiaries.

"Excess Cash" means the Consolidated Cash Balance (other than cash collateral in respect of Letters of Credit held by the Administrative Agent pursuant to Section 2.10(b)) in excess of the Excess Cash Threshold at any time, net of and reduced by, without duplication, (i) any cash set aside to pay in the ordinary course of business amounts then due and owing to third parties and for which Parent MLP and its Consolidated Subsidiaries have issued checks or initiated wires or ACH transfers (or will, within one (1) Business Day, issue checks or initiate wires or ACH transfers, and such amounts are disclosed in writing to the Administrative Agent, with reasonably detailed evidence thereof to the extent requested by the Administrative Agent) in order to pay such amounts, (ii) any cash constituting purchase price deposits held in escrow by or on behalf of Parent MLP or any of its Consolidated Subsidiaries pursuant to a binding and enforceable purchase and sale agreement with an unaffiliated third party containing customary provisions regarding the payment and refunding of such deposits, (iii) any cash or cash equivalents to be used by Parent MLP or any of its Consolidated Subsidiaries within five (5) Business Days to pay the purchase price for any Property to be acquired by Parent MLP or such Consolidated Subsidiary pursuant to a binding and

enforceable purchase and sale agreement (a copy of which has been provided to the Administrative Agent) with an unaffiliated third party containing customary provisions regarding the payment of such purchase price, (iv) cash in an amount equal to the outstanding checks or initiated wires or ACH transfers issued by Parent MLP or any of its Consolidated Subsidiaries which have not yet been subtracted from the balance of the relevant accounts of Parent MLP or such Consolidated Subsidiary (which amounts are disclosed in writing to the Administrative Agent, with reasonably detailed evidence thereof to the extent requested by the Administrative Agent), and (v) any cash or cash equivalents described in the definition of “Excluded Accounts” which are held in any Excluded Account.

“Excess Cash Test Day” means (a) so long as no Event of Default or Deficiency has occurred and is continuing, the last Business Day of each calendar week and (b) at any time when any Event of Default or Deficiency has occurred and is continuing, each Business Day.

“Excess Cash Threshold” means, at any time, an amount equal to ten percent (10%) of the Aggregate Elected Revolving Commitment Amount at such time.

1.2 Revolving Loans. The proviso at the end of the first sentence of Section 2.01(a) of the Credit Agreement is hereby amended by adding “(x)” immediately following “provided, however, that” and adding the following at the end thereof:

and (y) after giving *pro forma* effect to such Revolving Loans, and any application of the proceeds thereof on the date of such Revolving Loans, Parent MLP and its Consolidated Subsidiaries shall not have any Excess Cash.

1.3 Revolving Borrowings. The reference to “and, in the case of Revolving Eurodollar Loans” in Section 2.02(a) of the Credit Agreement is hereby amended to refer instead to “and amount of Excess Cash, if any (after giving *pro forma* effect to such Revolving Borrowing and any application of the proceeds thereof on the date of such Revolving Borrowing), and, in the case of Revolving Eurodollar Loans”.

1.4 Mandatory Prepayments. Section 2.07(b) of the Credit Agreement is hereby amended by adding a new clause (iv) at the end thereof, to read as follows:

(iv) If, at the end of any Excess Cash Test Day, (A) there is any outstanding Revolving Loans or LC Exposure and (B) there is any Excess Cash, then the Borrower shall, on the next Business Day, (1) prepay the Revolving Loans in an aggregate principal amount equal to the lesser of the aggregate outstanding principal amount of all such Revolving Loans and the amount of such Excess Cash, and (2) if after prepaying all of the Revolving Loans there is both LC Exposure and Excess Cash, pay to the Administrative Agent on behalf of the Lenders an amount equal to the lesser of such LC Exposure and the remaining amount of Excess Cash to be held as cash collateral as provided in Section 2.10(b); provided that no such prepayment need be made under this Section 2.07(b)(iv) if the amount thereof would be less than \$500,000; provided, further,

that all payments required to be made pursuant to this Section 2.07(b)(iv) must be made on or prior to the Termination Date. To the extent that there are funds on deposit in, or credited to, any Deposit Account or other account maintained with the Administrative Agent (or any Affiliate thereof) or any Lender (or any Affiliate thereof) on any date that the Borrower is required to prepay Revolving Loans (and/or cash collateralize LC Exposure, as applicable) pursuant to this Section 2.07(b)(iv), the Borrower hereby irrevocably authorizes and instructs the Administrative Agent or such Lender to apply such funds to the prepayment of Revolving Loans (and/or cash collateralization of LC Exposure, as applicable).

1.5 Conditions Precedent - Subsequent Loans and Letters of Credit. The first sentence of Section 6.02 of the Credit Agreement is hereby amended by deleting “and” at the end of clause (d) thereof, inserting “; and” at the end of clause (e) thereof, and adding a new clause (f) immediately following clause (e) thereof, to read as follows:

(f) at the time of and immediately after giving effect to any Revolving Loans and any application of the proceeds thereof on the date of such requested Borrowing, Parent MLP and its Consolidated Subsidiaries shall not have any Excess Cash.

1.6 Excess Cash Information. Article VIII of the Credit Agreement is hereby amended by adding a new Section 8.15 at the end thereof, to read as follows:

8.15 Excess Cash Information. Upon the request of the Administrative Agent, within one (1) Business Day of any such request, and on any Excess Cash Test Day on which Parent MLP or any Consolidated Subsidiary has any Excess Cash, the Borrower shall provide to the Administrative Agent, summary and balance statements, in a form reasonably acceptable to the Administrative Agent, for each Deposit Account, Securities Account or other account in which any of the Consolidated Cash Balance is held, credited or carried, together with a written statement setting forth a reasonably detailed calculation of Excess Cash, setting forth amounts excluded therefrom pursuant to the parenthetical set forth in the definition thereof.

1.7 Events of Default. The two references to “Article IX” in Sec. 10.01(d) of the Credit Agreement are hereby amended to refer instead to “Section 8.09(d), Section 8.15 or Article IX”.

1.8 Acknowledgment Regarding Any Supported QFCs. Article XII of the Credit Agreement is hereby amended by adding a new Section 12.21 at the end thereof, to read as follows:

Section 12.21. Acknowledgement Regarding Any Supported QFCs. To the extent that the Loan Documents provide support, through a guarantee or otherwise, for Hedging Agreements or any other agreement or instrument that is a QFC (such support, “QFC Credit Support” and, each such QFC, a “Supported QFC”), the parties acknowledge and agree as follows with respect to the resolution power of the FDIC under the Federal Deposit Insurance Act and Title II of the Dodd-Frank Wall Street Reform and

Consumer Protection Act (together with the regulations promulgated thereunder, the “U.S. Special Resolution Regimes”) in respect of such Supported QFC and QFC Credit Support (with the provisions below applicable notwithstanding that the Loan Documents and any Supported QFC may in fact be stated to be governed by the laws of the State of New York and/or of the United States or any other state of the United States):

(a) In the event a Covered Entity that is party to a Supported QFC (each, a “Covered Party”) becomes subject to a proceeding under a U.S. Special Resolution Regime, the transfer of such Supported QFC and the benefit of such QFC Credit Support (and any interest and obligation in or under such Supported QFC and such QFC Credit Support, and any rights in property securing such Supported QFC or such QFC Credit Support) from such Covered Party will be effective to the same extent as the transfer would be effective under the U.S. Special Resolution Regime if the Supported QFC and such QFC Credit Support (and any such interest, obligation and rights in property) were governed by the laws of the United States or a state of the United States. In the event a Covered Party or a BHC Act Affiliate of a Covered Party becomes subject to a proceeding under a U.S. Special Resolution Regime, Default Rights under the Loan Documents that might otherwise apply to such Supported QFC or any QFC Credit Support that may be exercised against such Covered Party are permitted to be exercised to no greater extent than such Default Rights could be exercised under the U.S. Special Resolution Regime if the Supported QFC and the Loan Documents were governed by the laws of the United States or a state of the United States. Without limitation of the foregoing, it is understood and agreed that rights and remedies of the parties with respect to a Defaulting Lender shall in no event affect the rights of any Covered Party with respect to a Supported QFC or any QFC Credit Support.

(b) As used in this Section 12.21, the following terms have the following meanings:

“BHC Act Affiliate” of a party means an “affiliate” (as such term is defined under, and interpreted in accordance with, 12 U.S.C. 1841(k)) of such party.

“Covered Entity” means any of the following:

- (i) a “covered entity” as that term is defined in, and interpreted in accordance with, 12 C.F.R. § 252.82(b);
- (ii) a “covered bank” as that term is defined in, and interpreted in accordance with, 12 C.F.R. § 47.3(b); or
- (iii) a “covered FSI” as that term is defined in, and interpreted in accordance with, 12 C.F.R. § 382.2(b).

“Default Right” has the meaning assigned to that term in, and shall be interpreted in accordance with, 12 C.F.R. §§ 252.81, 47.2 or 382.1, as applicable.

“QFC” has the meaning assigned to the term “qualified financial contract” in, and shall be interpreted in accordance with, 12 U.S.C. 5390(c)(8)(D).

1.9 Exhibits. Exhibit B-1 to the Credit Agreement is hereby amended its entirety to read as set forth in Exhibit B-1 attached hereto.

Section 2. Borrowing Base.

2.1 Pursuant to Section 2.08(d) of the Credit Agreement, Administrative Agent hereby notifies Borrower and Revolving Lenders that pursuant to the April 1, 2020 Scheduled Redetermination of the Borrowing Base pursuant to Section 2.08(c) of the Credit Agreement, from and after the date hereof until the next redetermination of the Borrowing Base, the amount of the Borrowing Base shall be \$460,000,000.

Section 3. Miscellaneous.

3.1 Confirmation. The provisions of the Credit Agreement, as amended hereby, shall remain in full force and effect following the effectiveness hereof.

3.2 Ratification and Affirmation; Representations and Warranties. Each of Borrower and Parent MLP hereby (a) ratifies and affirms each Loan Party’s obligations under, and acknowledges each Loan Party’s continued liability under, each Loan Document to which such Loan Party is a party and agrees that each Loan Document to which any Loan Party is a party remains in full force and effect as expressly amended hereby and (b) represents and warrants to Administrative Agent and Lenders that as of the date hereof, after giving effect to the terms hereof:

(i) all of the representations and warranties contained in each Loan Document to which any Loan Party is a party are true and correct in all material respects (unless otherwise qualified as to materiality), except to the extent any such representations and warranties are expressly limited to an earlier date, in which case, such representations and warranties shall continue to be true and correct as of such specified earlier date,

(ii) no Default or Event of Default has occurred and is continuing, and

(iii) no event or events have occurred which individually or in the aggregate could reasonably be expected to have a Material Adverse Effect.

3.3 Counterparts. This Amendment may be executed by one or more of the parties hereto in any number of separate counterparts, and all of such counterparts taken together shall be deemed to constitute one and the same instrument. Delivery of this Amendment by electronic transmission shall be effective as delivery of a manually executed counterpart hereof.

3.4 NO ORAL AGREEMENT. THIS AMENDMENT, THE CREDIT AGREEMENT AND THE OTHER LOAN DOCUMENTS EXECUTED IN CONNECTION HERewith AND THEREwith REPRESENT THE FINAL AGREEMENT BETWEEN THE PARTIES AND MAY NOT BE CONTRADICTED BY

EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR SUBSEQUENT UNWRITTEN ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN THE PARTIES.

3.5 GOVERNING LAW. THIS AMENDMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF TEXAS.

3.6 Loan Document. This Amendment is a Loan Document.

[Signature pages follow]

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be duly executed as of the date first written above.

BLACK STONE MINERALS COMPANY, L.P., as Borrower

By: BSMC GP, L.L.C., its General Partner

By: Black Stone Minerals, L.P., its Sole Member

By: Black Stone Minerals GP, L.L.C.,
its General Partner

By: /s/ Jeffrey P. Wood

Name: Jeffrey P. Wood

Title: President and Chief Financial Officer

BLACK STONE MINERALS, L.P.,
as Parent MLP

By: Black Stone Minerals GP, L.L.C.,
its General Partner

By: /s/ Jeffrey P. Wood

Name: Jeffrey P. Wood

Title: President and Chief Financial Officer

Third Amendment
Black Stone Minerals Credit Agreement

WELLS FARGO BANK, NATIONAL ASSOCIATION,
as Administrative Agent, Issuing Bank and a Lender

By: /s/ Carroll Cartwright
Name: Carroll Cartwright
Title: Vice President

Third Amendment
Black Stone Minerals Credit Agreement

BANK OF AMERICA, N.A.,
as a Lender

By: /s/ Alia Qaddumi
Name: Alia Qaddumi
Title: Director

Third Amendment
Black Stone Minerals Credit Agreement

BBVA USA,
as a Lender

By: /s/ Julia Barnhill
Name: Julia Barnhill
Title: Vice President

Third Amendment
Black Stone Minerals Credit Agreement

JPMORGAN CHASE BANK, N.A.,
as a Lender

By: /s/ Dalton Harris
Name: Dalton Harris
Title: Authorized Officer

Third Amendment
Black Stone Minerals Credit Agreement

ZB, N.A. DBA AMEGY BANK,
as a Lender

By: /s/ Sam Trail
Name: Sam Trail
Title: Senior Vice President

Third Amendment
Black Stone Minerals Credit Agreement

THE BANK OF NOVA SCOTIA,
HOUSTON BRANCH,
as a Lender

By: /s/ Ryan Knape
Name: Ryan Knape
Title: Director

Third Amendment
Black Stone Minerals Credit Agreement

ABN AMRO CAPITAL USA LLC,
as a Lender

By: /s/ Darrell Holley
Name: Darrell Holley
Title: Managing Director

By: /s/ Michaela Braun
Name: Michaela Braun
Title: Executive Director

Third Amendment
Black Stone Minerals Credit Agreement

COMERICA BANK,
as a Lender

By: /s/ Britney P. Geidel
Name: Britney P. Geidel
Title: Portfolio Manager, AVP

Third Amendment
Black Stone Minerals Credit Agreement

KEYBANK NATIONAL ASSOCIATION,
as a Lender

By: /s/ David M. Bornstein
Name: David M. Bornstein
Title: Senior Vice President

Third Amendment
Black Stone Minerals Credit Agreement

TEXAS CAPITAL BANK, N.A.,
as a Lender

By: /s/ Jamie Hibbert
Name: Jamie Hibbert
Title: Vice President

Third Amendment
Black Stone Minerals Credit Agreement

BOKF NA, DBA BANK OF TEXAS,
as a Lender

By: /s/ Taylor Morris
Name: Taylor Morris
Title: VP - Energy Lending

Third Amendment
Black Stone Minerals Credit Agreement

EXHIBIT B-1
FORM OF REVOLVING BORROWING, CONTINUATION AND CONVERSION REQUEST

_____, 20__

BLACK STONE MINERALS COMPANY, L.P., a Delaware limited partnership (the "Borrower"), pursuant to the Fourth Amended and Restated Credit Agreement dated as of November 1, 2017 (together with all amendments or supplements thereto, the "Credit Agreement") among the Borrower, the Parent MLP, Wells Fargo Bank, National Association, as Administrative Agent and the other agents and lenders (the "Lenders") which are or become parties thereto, and such Lenders makes the requests indicated below (unless otherwise defined herein, capitalized terms are defined in the Credit Agreement):

1. Revolving Borrowings:

- (a) Aggregate amount of new Revolving Loans to be \$ _____;
- (b) Requested funding date is _____, 20__;
- (c) \$ _____ of such Revolving Borrowings are to be Revolving Eurodollar Loans;
\$ _____ of such Revolving Borrowings are to be Revolving Base Rate Loans; and
- (d) Length of Interest Period for Revolving Eurodollar Loans is:

- (e) Amount of Borrowing Base currently in effect: \$ _____
- (f) Amount of Aggregate Elected Revolving Commitment Amount in effect: \$ _____
- (g) Amount of outstanding Revolving Loans, LC Exposure and Swingline Exposure \$ _____
- (h) Available amount [least of (e), (f) or Aggregate Maximum Credit Amounts,
minus (g)] \$ _____
[amount requested in (a) cannot exceed (h)]
- (i) Amount of Excess Cash: \$ _____
[cannot exceed 10% of the Aggregate Elected Revolving Commitment Amount]

2. Continuation for Revolving Eurodollar Loans maturing on _____:

(a) Aggregate amount to be continued as Revolving Eurodollar Loans is \$_____;

(b) Aggregate amount to be converted to Revolving Base Rate Loans is \$_____;

(c) Length of Interest Period for continued Revolving Eurodollar Loans is _____.

3. Conversion of outstanding Revolving Base Rate Loans to Revolving Eurodollar Loans:

Convert \$_____ of the outstanding Revolving Base Rate Loans to Revolving Eurodollar Loans on _____ with an Interest Period of _____.

4. Conversion of outstanding Revolving Eurodollar Loans to Revolving Base Rate Loans:

Convert \$_____ of the outstanding Revolving Eurodollar Loans with Interest Period maturing on _____, 20__, to Revolving Base Rate Loans.

The undersigned certifies that he/she is the _____ of the General Partner, and that as such he is authorized to execute this certificate on behalf of the Borrower. The undersigned further certifies, represents and warrants on behalf of the Borrower that the Borrower is entitled to receive the requested Revolving Borrowing, continuation or conversion under the terms and conditions of the Credit Agreement.

BLACK STONE MINERALS COMPANY, L.P.

By: BSMC GP, L.L.C.
general partner

By: Black Stone Minerals, L.P.
its Sole Member

By: Black Stone Minerals GP, L.L.C.
its General Partner

By: ____
Name: ____
Title: ____

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

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

1. I have reviewed this report on Form 10-Q of Black Stone Minerals, L.P. (the “registrant”);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: May 5, 2020

/s/ Thomas L. Carter, Jr.

Thomas L. Carter, Jr.

Chief Executive Officer

Black Stone Minerals GP, L.L.C.,

the general partner of Black Stone Minerals, L.P.

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

I, Jeffrey P. Wood, certify that:

1. I have reviewed this report on Form 10-Q of Black Stone Minerals, L.P. (the “registrant”);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: May 5, 2020

/s/ Jeffrey P. Wood

Jeffrey P. Wood

Chief Financial Officer

Black Stone Minerals GP, L.L.C.,

the general partner of Black Stone Minerals, L.P.

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

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

- (1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: May 5, 2020

/s/ Thomas L. Carter, Jr.

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

Date: May 5, 2020

/s/ Jeffrey P. Wood

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