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 June 30, 2021

OR

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

For the transition period _______________ to _______________

Commission File Number: 001-37362

Black Stone Minerals, L.P.

(Exact name of registrant as specified in its charter)

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

(713) 445-3200

(Registrant's telephone number, including area code)

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

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

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

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

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

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

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

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

As of July 30, 2021, there were 208,642,990 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)

	June 30, 2021	December 31, 2020
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 1,043	$ 1,796
Accounts receivable	68,381	61,908
Commodity derivative assets	—	1,149
Prepaid expenses and other current assets	2,116	1,668
TOTAL CURRENT ASSETS	71,540	66,521
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, at cost, using the successful efforts method of accounting, includes unproved properties of $947,509 and $937,464 at June 30, 2021 and December 31, 2020, respectively	3,187,176	3,157,818
Accumulated depreciation, depletion, amortization, and impairment	(2,025,503)	(1,987,332)
Oil and natural gas properties, net	1,161,673	1,170,486
Other property and equipment, net of accumulated depreciation of $12,613 and $12,292 at June 30, 2021 and December 31, 2020, respectively	1,393	1,650
NET PROPERTY AND EQUIPMENT	1,163,066	1,172,136
DEFERRED CHARGES AND OTHER LONG-TERM ASSETS	7,641	5,321
TOTAL ASSETS	$ 1,242,247	$ 1,243,978
LIABILITIES, MEZZANINE EQUITY, AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 3,320	$ 3,407
Accrued liabilities	9,925	15,568
Commodity derivative liabilities	80,047	19,318
Other current liabilities	1,792	1,654
TOTAL CURRENT LIABILITIES	95,084	39,947
LONG–TERM LIABILITIES		
Credit facility	96,000	121,000
Accrued incentive compensation	371	766
Commodity derivative liabilities	5,464	1,848
Asset retirement obligations	17,741	17,377
Other long-term liabilities	3,533	4,073
TOTAL LIABILITIES	218,193	185,011
COMMITMENTS AND CONTINGENCIES (Note 7)		
MEZZANINE EQUITY		
Partners' equity – Series B cumulative convertible preferred units, 14,711 units outstanding at June 30, 2021 and December 31, 2020	298,361	298,361
EQUITY		
Partners' equity – general partner interest	—	—
Partners' equity – common units, 208,637 and 206,749 units outstanding at June 30, 2021 and December 31, 2020, respectively	725,693	760,606
TOTAL EQUITY	725,693	760,606
TOTAL LIABILITIES, MEZZANINE EQUITY, AND EQUITY	$ 1,242,247	$ 1,243,978

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 June 30,		Six Months Ended June 30,	
	2021	**2020**	**2021**	**2020**
REVENUE				
Oil and condensate sales	$ 53,936	$ 25,417	$ 98,112	$ 77,510
Natural gas and natural gas liquids sales	56,481	30,311	99,370	66,953
Lease bonus and other income	7,505	1,975	9,890	6,283
Revenue from contracts with customers	117,922	57,703	207,372	150,746
Gain (loss) on commodity derivative instruments	(59,480)	(19,174)	(87,362)	70,837
TOTAL REVENUE	58,442	38,529	120,010	221,583
OPERATING (INCOME) EXPENSE				
Lease operating expense	3,837	3,293	6,501	7,120
Production costs and ad valorem taxes	9,296	9,555	21,138	21,931
Exploration expense	2	23	1,075	24
Depreciation, depletion, and amortization	15,796	19,193	31,428	42,375
Impairment of oil and natural gas properties	—	—	—	51,031
General and administrative	12,187	11,501	25,039	23,357
Accretion of asset retirement obligations	298	278	590	550
TOTAL OPERATING EXPENSE	41,416	43,843	85,771	146,388
INCOME (LOSS) FROM OPERATIONS	17,026	(5,314)	34,239	75,195
OTHER INCOME (EXPENSE)				
Interest and investment income	—	3	—	34
Interest expense	(1,628)	(2,964)	(2,838)	(7,391)
Other income (expense)	31	(96)	214	(97)
TOTAL OTHER EXPENSE	(1,597)	(3,057)	(2,624)	(7,454)
NET INCOME (LOSS)	15,429	(8,371)	31,615	67,741
Distributions on Series B cumulative convertible preferred units	(5,250)	(5,250)	(10,500)	(10,500)
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON UNITS	$ 10,179	$ (13,621)	$ 21,115	$ 57,241
ALLOCATION OF NET INCOME (LOSS):				
General partner interest	$ —	$ —	$ —	$ —
Common units	10,179	(13,621)	21,115	57,241
	$ 10,179	$ (13,621)	$ 21,115	$ 57,241
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON UNIT:				
Per common unit (basic)	$ 0.05	$ (0.07)	$ 0.10	$ 0.28
Per common unit (diluted)	$ 0.05	$ (0.07)	$ 0.10	$ 0.28
WEIGHTED AVERAGE COMMON UNITS OUTSTANDING:				
Weighted average common units outstanding (basic)	207,945	206,707	207,695	206,669
Weighted average common units outstanding (diluted)	207,945	206,707	207,695	206,669

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, 2020	206,749	$ 760,606	$ 760,606
Repurchases of common units	(223)	(1,957)	(1,957)
Restricted units granted, net of forfeitures	1,016	—	—
Equity–based compensation	—	5,353	5,353
Distributions	—	(36,272)	(36,272)
Charges to partners' equity for accrued distribution equivalent rights	—	(237)	(237)
Distributions on Series B cumulative convertible preferred units	—	(5,250)	(5,250)
Net income (loss)	—	16,186	16,186
BALANCE AT MARCH 31, 2021	207,542	$ 738,429	$ 738,429
Issuance of common units for property acquisitions	1,088	10,766	10,766
Restricted units granted, net of forfeitures	7	—	—
Equity–based compensation	—	2,820	2,820
Distributions	—	(36,321)	(36,321)
Charges to partners' equity for accrued distribution equivalent rights	—	(180)	(180)
Distributions on Series B cumulative convertible preferred units	—	(5,250)	(5,250)
Net income (loss)	—	15,429	15,429
BALANCE AT JUNE 30, 2021	208,637	$ 725,693	$ 725,693

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
Repurchases of common units	—	(6)	(6)
Restricted units granted, net of forfeitures	14	—	—
Equity–based compensation	—	2,292	2,292
Distributions	—	(16,679)	(16,679)
Charges to partners' equity for accrued distribution equivalent rights	—	(31)	(31)
Distributions on Series B cumulative convertible preferred units	—	(5,250)	(5,250)
Net income (loss)	—	(8,371)	(8,371)
BALANCE AT JUNE 30, 2020	206,709	$ 775,681	$ 775,681

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)

	Six Months Ended June 30,	
	2021	**2020**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income (loss)	$ 31,615	$ 67,741
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, and amortization	31,428	42,375
Impairment of oil and natural gas properties	—	51,031
Accretion of asset retirement obligations	590	550
Amortization of deferred charges	884	519
(Gain) loss on commodity derivative instruments	87,362	(70,837)
Net cash (paid) received on settlement of commodity derivative instruments	(21,868)	45,506
Equity-based compensation	6,533	(420)
Exploratory dry hole expense	1,049	—
Changes in operating assets and liabilities:		
Accounts receivable	(6,159)	33,544
Prepaid expenses and other current assets	(448)	(1,163)
Accounts payable, accrued liabilities, and other	(5,247)	(10,790)
Settlement of asset retirement obligations	(160)	(87)
NET CASH PROVIDED BY OPERATING ACTIVITIES	125,579	157,969
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisitions of oil and natural gas properties	(10,064)	(28)
Additions to oil and natural gas properties	(2,606)	(4,146)
Additions to oil and natural gas properties leasehold costs	(21)	(782)
Purchases of other property and equipment	(63)	(10)
Proceeds from the sale of oil and natural gas properties	—	1,266
Proceeds from farmouts of oil and natural gas properties	—	4,067
NET CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES	(12,754)	367
CASH FLOWS FROM FINANCING ACTIVITIES		
Distributions to common unitholders	(72,593)	(78,320)
Distributions to Series B cumulative convertible preferred unitholders	(10,500)	(10,500)
Repurchases of common units	(1,957)	(5,035)
Borrowings under credit facility	84,000	89,000
Repayments under credit facility	(109,000)	(160,000)
Debt issuance costs and other	(3,528)	—
NET CASH USED IN FINANCING ACTIVITIES	(113,578)	(164,855)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(753)	(6,519)
CASH AND CASH EQUIVALENTS – beginning of the period	1,796	8,119
CASH AND CASH EQUIVALENTS – end of the period	$ 1,043	$ 1,600
SUPPLEMENTAL DISCLOSURE		
Interest paid	$ 1,944	$ 6,934

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

NOTE 1 - BUSINESS AND BASIS OF PRESENTATION

Description of the Business

Black Stone Minerals, L.P. (“BSM” or the “Partnership”) is a publicly traded Delaware limited partnership that owns oil and natural gas mineral interests, which make up the vast majority of the asset base. The Partnership's assets also include nonparticipating royalty interests and overriding royalty interests. These interests, which are substantially non-cost-bearing, are collectively referred to as “mineral and royalty interests.” The Partnership’s mineral and royalty interests are located in 41 states in the continental United States ("U.S."), including all of the major onshore producing basins. The Partnership also owns non-operated working interests in certain oil and natural gas properties. 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, 2020 ("2020 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 six months ended June 30, 2021 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.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Significant Accounting Policies

Significant accounting policies are disclosed in the Partnership's 2020 Annual Report on Form 10-K. There have been no changes in such policies or the application of such policies during the six months ended June 30, 2021.

Accounts Receivable

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

	June 30, 2021		December 31, 2020	
	(in thousands)			
Accounts receivable:				
Revenues from contracts with customers	$	63,706	$	58,181
Other		4,675		3,727
Total accounts receivable	$	68,381	$	61,908

NOTE 3 - OIL AND NATURAL GAS PROPERTIES

Acquisitions

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.

In the second quarter of 2021, the Partnership closed an acquisition of mineral and royalty acreage in the northern Midland Basin for total consideration of $20.8 million. The purchase price consisted of $10.0 million in cash and $10.8 million in common units of the Partnership. The cash consideration was funded with borrowings under the Credit Facility (as defined in Note 6 - Credit Facility) and funds from operating activities. The transaction was accounted for as a business combination with the assets acquired recorded at their estimated fair values as of the acquisition date. The assets acquired consisted of $4.9 million of proved oil and natural gas properties, $15.6 million of unproved oil and natural gas properties, and $0.3 million of net working capital. Acquisition related costs of $0.3 million were expensed and included in the General and administrative line of the consolidated statement of operations for the three and six months ended June 30, 2021.

Divestitures

In the third quarter of 2020, the Partnership closed two separate divestitures of certain mineral and royalty properties in the Permian Basin for total proceeds, after closing adjustments, of $150.6 million. One of these transactions, effective May 1, 2020, involved the sale of the Partnership's mineral and royalty interest in specific tracts in Midland County, Texas for net proceeds of approximately $54.5 million. The other transaction, effective July 1, 2020, involved the sale of an undivided interest across parts of the Partnership's Delaware Basin and Midland Basin positions for net proceeds of approximately $96.1 million. The total book value of the assets divested through these transactions was $126.6 million at the time of sale. The Partnership recognized a $24.0 million gain associated with the divestitures in the third quarter of 2020.

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 mineral and royalty interest 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

In February 2017, the Partnership entered into a farmout agreement (the "First Canaan Farmout") with Canaan Resource Partners ("Canaan") covering certain Haynesville and Bossier shale acreage in San Augustine County, Texas jointly owned with and operated by XTO Energy Inc. ("XTO"), a subsidiary of Exxon Mobil Corporation. The Partnership had an approximate 50% working interest in the acreage. Under the terms of the First Canaan Farmout, Canaan funded 80% of the Partnership's drilling and completion costs and was assigned 80% of the Partnership's working interests in covered wells (40% working interest on an 8/8ths basis) as the wells were drilled. The Partnership received an ORRI before payout and an increased ORRI after payout on all wells drilled under the First Canaan Farmout.

Canaan's rights and obligations to participate in future wells in the contract area were terminated in the second quarter of 2021 in conjunction with Canaan and the Partnership entering into a new farmout agreement as discussed below. Canaan participated in a total of 37 wells under the First Canaan Farmout.

In 2019, XTO Energy Inc. suspended its development activities in the area due to low natural gas prices. In March 2021, BSM and XTO reached an agreement to partition the jointly owned working interests in the San Augustine County development area. Under the partition agreement, BSM and XTO exchanged working interests in certain existing and proposed drilling units, resulting in each company holding 100% of the working interests in their respective partitioned units.

In May 2021, BSM and Aethon Energy ("Aethon") entered into an agreement to develop certain of the Partnership's undeveloped acreage in San Augustine County, including the working interests resulting from the partition agreement discussed above. The agreement provides for minimum well commitments by Aethon in exchange for reduced royalty rates and exclusive access to BSM's mineral and leasehold acreage in the contract area. The agreement calls for a minimum of five wells to be drilled in the initial program year, which begins in the third quarter of 2021, increasing to a minimum of 12 wells per year beginning with the fourth program year. The Partnership's development agreement with Aethon and related drilling commitments covering its San Augustine County acreage is independent of the development agreement and associated commitments covering Angelina County discussed below.

On May 25, 2021, the Partnership and Canaan entered into a new farmout agreement (the "Second Canaan Farmout"). The Second Canaan Farmout supersedes and replaces the First Canaan Farmout with respect to the area in San Augustine County covered by the Aethon development agreement. The Second Canaan Farmout covers part of the Partnership's share of working interests under active development by Aethon in San Augustine County, Texas and continues until May 2031, unless earlier terminated in accordance to the terms of the agreement. Canaan will earn 80% of the Partnership's working interest in the partitioned acreage from XTO (up to a maximum of 40% on an 8/8ths basis) and 50% of the Partnership's working interest in other areas (up to a maximum of 12.5% on an 8/8ths basis) in wells drilled and operated by Aethon in accordance with the development agreement. Canaan is obligated to fund the development of all wells drilled by Aethon in the initial program year and thereafter, Canaan has certain rights and options to continue funding the Partnership's working interest for the duration of the Second Canaan Farmout. As of June 30, 2021, no wells had been drilled under the Second Canaan Farmout. The Partnership will receive an ORRI before payout and an increased ORRI after payout on all wells drilled under the Second Canaan Farmout.

Pivotal Farmout

In November 2017, the Partnership entered into a farmout agreement (the "First Pivotal Farmout") 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 in wells operated by XTO Energy and BPX Energy 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 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 June 30, 2021, a total of 68 wells have been spud in the contract area subject to the First Pivotal Farmout. The Partnership's development agreement with BPX Energy terminated in 2019 with respect to the majority of the Partnership's acreage covered by the agreement. As such, Pivotal retains minimal rights or obligations related to the farmout for that area that remains subject to the First Pivotal Farmout.

In the second quarter of 2020, the Partnership entered into a development agreement with Aethon to develop certain portions of the area forfeited by BPX Energy 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 began in the third quarter of 2020, increasing to a minimum of 15 wells per year beginning with the third program year. In November 2020, the Partnership entered into a new farmout agreement (the "Second Pivotal Farmout") with Pivotal. The Second Pivotal Farmout supersedes and replaces the First Pivotal Farmout with respect to the area covered by the Aethon development agreement. The Second Pivotal Farmout covers the Partnership's share of working interest under active development by Aethon in Angelina County, Texas and continues until April 2028, unless earlier terminated in accordance to the terms of the agreement. Pivotal will earn 100% of the Partnership's working interest (ranging from approximately 12.5% to 25% on an 8/8ths basis) in wells drilled and operated by Aethon in accordance with the development agreement. Pivotal is obligated to fund the development of all wells drilled by Aethon in the initial program year and thereafter, Pivotal has certain rights and options to continue funding the Partnership's working interests for the duration of the Second Pivotal Farmout. 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 June 30, 2021, a total of five wells have been spud in the contract area subject to the Second Pivotal Farmout.

From the inception of the farmout agreements through June 30, 2021, the Partnership has received $90.2 million and $119.2 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 June 30, 2021 and December 31, 2020, $0.1 million 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.

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 no impairment of oil and natural gas properties for the three and six months ended June 30, 2021 and the three months ended June 30, 2020. The Partnership recognized $51.0 million of impairment of oil and natural gas properties for the six months ended June 30, 2020. 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 June 30, 2021, the Partnership’s open derivative contracts consisted of fixed-price swap contracts. A fixed-price swap contract between the Partnership and the counterparty specifies a fixed commodity price and a future settlement date. The Partnership has not designated any of its contracts as fair value or cash flow hedges. Accordingly, 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 June 30, 2021 and December 31, 2020. 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 June 30, 2021, the Partnership had seven counterparties, all of which are rated Baa1 or better by Moody's and six are lenders under the Credit Facility.

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

		June 30, 2021		
Classification	**Balance Sheet Location**	**Gross Fair Value**	**Effect of Counterparty Netting**	**Net Carrying Value on Balance Sheet**
			(in thousands)	
Assets:				
Current asset	Commodity derivative assets	$ —	$ —	$ —
Long-term asset	Deferred charges and other long-term assets	977	(977)	—
Total assets		$ 977	$ (977)	$ —
Liabilities:				
Current liability	Commodity derivative liabilities	$ 80,047	$ —	$ 80,047
Long-term liability	Commodity derivative liabilities	6,441	(977)	5,464
Total liabilities		$ 86,488	$ (977)	$ 85,511

		December 31, 2020		
Classification	**Balance Sheet Location**	**Gross Fair Value**	**Effect of Counterparty Netting**	**Net Carrying Value on Balance Sheet**
			(in thousands)	
Assets:				
Current asset	Commodity derivative assets	$ 6,362	$ (5,213)	$ 1,149
Long-term asset	Deferred charges and other long-term assets	—	—	—
Total assets		$ 6,362	$ (5,213)	$ 1,149
Liabilities:				
Current liability	Commodity derivative liabilities	$ 24,531	$ (5,213)	$ 19,318
Long-term liability	Commodity derivative liabilities	1,848	—	1,848
Total liabilities		$ 26,379	$ (5,213)	$ 21,166

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 June 30, 2021	Three Months Ended June 30, 2020	Six Months Ended June 30, 2021	Six Months Ended June 30, 2020
	(in thousands)			
Beginning fair value of commodity derivative instruments	$ (43,376)	$ 96,278	$ (20,017)	$ 15,221
Gain (loss) on oil derivative instruments	(34,215)	(21,647)	(59,069)	56,164
Gain (loss) on natural gas derivative instruments	(25,265)	2,473	(28,293)	14,673
Net cash paid (received) on settlements of oil derivative instruments	15,910	(26,776)	20,412	(28,317)
Net cash paid (received) on settlements of natural gas derivative instruments	1,435	(9,776)	1,456	(17,189)
Net change in fair value of commodity derivative instruments	(42,135)	(55,726)	(65,494)	25,331
Ending fair value of commodity derivative instruments	$ (85,511)	$ 40,552	$ (85,511)	$ 40,552

The Partnership had the following open derivative contracts for oil as of June 30, 2021:

Period and Type of Contract	Volume (Bbl)	Weighted Average Price (Per Bbl)	Range (Per Bbl) Low	Range (Per Bbl) High
Oil Swap Contracts:				
2021				
Second Quarter	220,000	$ 38.97	$ 32.64	$ 46.50
Third Quarter	660,000	38.97	32.64	46.50
Fourth Quarter	660,000	38.97	32.64	46.50
2022				
First Quarter	480,000	$ 60.14	$ 55.29	$ 65.50
Second Quarter	480,000	60.14	55.29	65.50
Third Quarter	480,000	60.14	55.29	65.50
Fourth Quarter	480,000	60.14	55.29	65.50

The Partnership had the following open derivative contracts for natural gas as of June 30, 2021:

Period and Type of Contract	Volume (MMBtu)	Weighted Average Price (Per MMBtu)	Range (Per MMBtu) Low	Range (Per MMBtu) High
Natural Gas Swap Contracts:				
2021				
Third Quarter	10,120,000	$ 2.69	$ 2.52	$ 3.08
Fourth Quarter	10,120,000	2.69	2.52	3.08
2022				
First Quarter	7,920,000	$ 2.98	$ 2.80	$ 3.15
Second Quarter	8,000,000	2.99	2.80	3.15
Third Quarter	8,080,000	2.99	2.80	3.15
Fourth Quarter	8,080,000	2.99	2.80	3.15

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 June 30, 2021 and December 31, 2020 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 commodity derivative financial 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.

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 June 30, 2021					
Financial Assets					
Commodity derivative instruments	$ —	$ 977	$ —	$ (977)	$ —
Financial Liabilities					
Commodity derivative instruments	$ —	$ 86,488	$ —	$ (977)	$ 85,511
As of December 31, 2020					
Financial Assets					
Commodity derivative instruments	$ —	$ 6,362	$ —	$ (5,213)	$ 1,149
Financial Liabilities					
Commodity derivative instruments	$ —	$ 26,379	$ —	$ (5,213)	$ 21,166

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 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, and using an annual discount rate of 8%.

The following table presents information about the non-recurring fair value measurements of the impaired properties:

	Fair Value Measurements Using			
	Level 1	Level 2	Level 3	Impairment
			(in thousands)	
Three Months Ended June 30, 2021				
Impaired oil and natural gas properties	$ —	$ —	$ —	$ —
Three Months Ended June 30, 2020				
Impaired oil and natural gas properties	$ —	$ —	$ —	$ —
Six Months Ended June 30, 2021				
Impaired oil and natural gas properties	$ —	$ —	$ —	$ —
Six Months Ended June 30, 2020				
Impaired oil and natural gas properties	$ —	$ —	$ 2,044	$ 51,031

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 June 30, 2021 or December 31, 2020.

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, 2024. 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. The Partnership also has the right to request a redetermination following the acquisition of oil and natural gas properties in excess of 10% of the value of the borrowing base immediately prior to such acquisition. Effective November 3, 2020, the borrowing base redetermination reduced the borrowing base from $430.0 million to $400.0 million, and effective April 30, 2021, the borrowing base was reaffirmed at $400.0 million. The next semi-annual redetermination is scheduled for October 2021.

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. As of December 31, 2020, the applicable margin for the alternative base rate ranged from 1.00% to 2.00% and the applicable margin for LIBOR ranged from 2.00% to 3.00%, depending on the borrowings outstanding in relation to the borrowing base. As of June 30, 2021, the alternative base rate margin ranged from 1.50% to 2.50% and the LIBOR margin ranged from 2.50% to 3.50%.

The weighted-average interest rate of the Credit Facility was 2.60% and 2.40% as of June 30, 2021 and December 31, 2020, respectively. Accrued interest is payable at the end of each calendar quarter or at the end of each interest period, unless the interest period is longer than 90 days, in which case interest is payable at the end of every 90-day period. In addition, a commitment fee is payable at the end of each calendar quarter based on either a rate of 0.375% if the borrowing base utilization percentage is less than 50%, or 0.500% per annum if the borrowing base utilization percentage is equal to or greater than 50%. The Credit Facility is secured by substantially all of the Partnership’s 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. Distributions are not permitted if there is a default under the Credit Facility (including the failure to satisfy one of the financial covenants), if the availability under the Credit Facility is less than 10% of the lenders' commitments, or if total debt to EBITDAX is greater than 3.0. As of June 30, 2021, the Partnership was in compliance with all financial covenants in the Credit Facility.

The aggregate principal balance outstanding was $96.0 million and $121.0 million at June 30, 2021 and December 31, 2020, respectively. The unused portion of the available borrowings under the Credit Facility were $304.0 million and $279.0 million at June 30, 2021 and December 31, 2020, respectively.

On March 5, 2021, the U.K. Financial Conduct Authority announced that it intends to stop persuading or compelling banks to submit LIBOR rates after December 31, 2021 for the 1-week and 2-month U.S. dollar settings and after June 30, 2023 for the remaining U.S. dollar settings. Our Credit Facility includes provisions to determine a replacement rate for LIBOR if necessary during its term, based on the secured overnight financing rate published by the Federal Reserve Bank of New York (“SOFR”). We currently do not expect the transition from LIBOR to have a material impact on us.

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.

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 June 30, 2021 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 June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
	(in thousands)			
Cash—short and long-term incentive plans	$ 1,729	$ 506	$ 3,114	$ 1,469
Equity-based compensation—restricted common units	1,037	1,126	1,986	2,411
Equity-based compensation—restricted performance units[1]	1,697	1,098	3,858	(3,559)
Board of Directors incentive plan	337	250	689	728
Total incentive compensation expense	$ 4,800	$ 2,980	$ 9,647	$ 1,049

[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 six months ended June 30, 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.

The Series B cumulative convertible preferred units had a carrying value of $298.4 million, including accrued distributions of $5.3 million, as of June 30, 2021 and December 31, 2020. 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 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 unit:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
	(in thousands, except per unit amounts)			
NET INCOME (LOSS)	$ 15,429	$ (8,371)	$ 31,615	$ 67,741
Distributions on Series B cumulative convertible preferred units	(5,250)	(5,250)	(10,500)	(10,500)
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON UNITS	10,179	(13,621)	21,115	57,241
ALLOCATION OF NET INCOME (LOSS):				
General partner interest	$ —	$ —	$ —	$ —
Common units	10,179	(13,621)	21,115	57,241
	$ 10,179	$ (13,621)	$ 21,115	$ 57,241
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON UNIT:				
Per common unit (basic)	$ 0.05	$ (0.07)	$ 0.10	$ 0.28
Per common unit (diluted)	0.05	(0.07)	0.10	0.28
WEIGHTED AVERAGE COMMON UNITS OUTSTANDING:				
Weighted average common units outstanding (basic)	207,945	206,707	207,695	206,669
Effect of dilutive securities	—	—	—	—
Weighted average common units outstanding (diluted)	207,945	206,707	207,695	206,669

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 June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
	(in thousands)			
Potentially dilutive securities (common units):				
Series B cumulative convertible preferred units on an as-converted basis	14,969	14,969	14,969	14,969

NOTE 11 - COMMON UNITS

Common Units

The common units represent limited partner interests in the Partnership. The holders of common units are entitled to participate in distributions and exercise the rights and privileges provided to limited partners holding common units under the partnership agreement.

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, 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 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 unitholders:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Distributions declared and paid per common unit	$ 0.1750	$ 0.0800	$ 0.3500	$ 0.3800

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 six months ended June 30, 2021. As of June 30, 2021, 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 July 26, 2021, the Board approved a distribution for the three months ended June 30, 2021 of $0.25 per common unit. In determining the distribution level with respect to the second quarter, the Board considered a base distribution of $0.20 per unit, which it expects will be sustainable through the end of 2021, plus a special distribution of $0.05 per unit which reflects certain positive, non-recurring items in the quarter. Distributions will be payable on August 20, 2021 to unitholders of record at the close of business on August 13, 2021.

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, 2020 ("2020 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;
- 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;
- conservation measures and general concern about the environmental impact of the production and use of fossil fuels;
- cybersecurity incidents, including data security breaches or computer viruses; 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 2020 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 production and reserves over time, allowing the majority of generated cash flow to be distributed to unitholders.

As of June 30, 2021, our mineral and royalty interests were located in 41 states in the continental United States, including all of the major onshore producing basins. These non-cost-bearing interests include ownership in over 70,000 producing wells. We also own non-operated working interests, a significant portion of which are on our positions where we also have a mineral and royalty interest. We recognize oil and natural gas revenue from our mineral and royalty and non-operated working interests in producing wells when control of the oil and natural gas produced is transferred to the customer and collectability of the sales price is reasonably assured. Our other sources of revenue include mineral lease bonus and delay rentals, which are recognized as revenue according to the terms of the lease agreements.

Recent Developments

Acquisitions

In the second quarter of 2021, we closed an acquisition of mineral and royalty acreage in the northern Midland Basin for total consideration of $20.8 million. The purchase price consisted of $10.0 million in cash and $10.8 million in common units of the Partnership. The cash consideration was funded with borrowings under the Credit Facility and funds from operating activities. The assets acquired consisted of $4.9 million of proved oil and natural gas properties, $15.6 million of unproved oil and natural gas properties, and $0.3 million of net working capital.

Shelby Trough Update

Angelina County

Aethon has successfully turned to sales the initial two program wells and has commenced operations on four additional wells under the development agreement covering Angelina County. Under the terms of the agreement, Aethon must drill a minimum of four wells on our acreage in the first program year ending in September 2021, escalating to a minimum of 15 wells per program year starting with the third program year.

San Augustine County

In May 2021, we entered into an agreement with Aethon to develop certain of our undeveloped acreage in San Augustine County. The agreement provides for minimum well commitments by Aethon in exchange for reduced royalty rates and exclusive access to Black Stone's mineral and leasehold acreage in the contract area. The agreement calls for a minimum of five wells to be drilled in the initial program year, which begins in the third quarter of 2021, increasing to a minimum of 12 wells per year beginning with the fourth program year. Our development agreement with Aethon and related drilling commitments covering its San Augustine County acreage is independent of the development agreement and associated commitments covering Angelina County.

In May 2021, we entered into a new farmout agreement (the "Second Canaan Farmout") with Canaan Resource Partners ("Canaan"). The Second Canaan Farmout supersedes and replaces the original farmout agreement with Canaan with respect to the area in San Augustine County covered by the Aethon development agreement. The Second Canaan Farmout covers part of our share of working interests under active development by Aethon in San Augustine County, Texas and continues until May 2031, unless earlier terminated in accordance to the terms of the agreement. Canaan will earn 80% of our working interest in the partitioned acreage from XTO (up to a maximum of 40% on an 8/8ths basis) and 50% of our working interest in other areas (up to a maximum of 12.5% on an 8/8ths basis) in wells drilled and operated by Aethon in accordance with the development agreement. Canaan is obligated to fund the development of all wells drilled by Aethon in the initial program year and thereafter, Canaan has certain rights and options to continue funding our working interests for the duration of the Second Canaan Farmout. As of June 30, 2021, no wells had been drilled under the Second Canaan Farmout. We will receive an ORRI before payout and an increased ORRI after payout on all wells drilled under the Second Canaan Farmout.

Austin Chalk Update

In April 2021, we entered into an agreement with several operators to test and develop areas of the Austin Chalk in East Texas where we have significant acreage positions. Recent drilling results have shown that advances in fracturing and other completion techniques can dramatically improve well performance in existing Austin Chalk fields. Under the terms of the agreement, the operators will participate in three test wells targeting the Austin Chalk formation. Two of the wells under the test program are currently being drilled, and the third well has been permitted. In addition to the test program, we have entered into a development agreement with one of the operators and are negotiating separate agreements with each remaining operator to further develop the acreage.

In April 2021, we also entered into an agreement with a large, private independent operator to drill and complete multiple Austin Chalk wells on our acreage within East Texas. We expect the operator to spud two wells on the acreage in 2021. If the initial wells are successful, the operator has the option to expand the Austin Chalk development program on additional additional acreage owned by us.

In February of 2021, we entered into an agreement with a large, publicly traded independent operator by which the operator will undertake a program to drill, test, and complete wells in the Austin Chalk formation on certain of our acreage in East Texas. The first well under this agreement is scheduled to be spud in the third or fourth quarter of 2021. If the initial wells are successful, the operator has the option to expand the Austin Chalk drilling program over a significant acreage position, the majority of which is owned and controlled by us.

New Sustainability Initiative

In July of 2021, we announced a new sustainability initiative in which we will use proceeds from surface use waivers on our mineral acreage supporting solar development to purchase carbon credits in an effort to offset part of the CO_2 emissions associated with our mineral production.

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 has adversely affected the global economy, disrupted global supply chains and created significant volatility in the financial markets. With widespread availability of vaccines, the U.S. Centers for Disease Control and Prevention has revised its guidance, travel restrictions have started to lift, and businesses have reopened. We have provisionally implemented a hybrid work approach, providing employees flexibility with work arrangements and the ability to collaborate with colleagues. All employees are assigned remote work days along with in-office work days. We do not expect these arrangements to negatively impact our ability to maintain operations. We continue to prioritize the health and safety of our workforce through frequent cleaning of common spaces, appropriate physical distancing measures, and other best practices as recommended by federal, state and local officials. We continue to monitor the spread of COVID-19 in the community, especially those resulting from new variants, and we will adjust our workplace policies accordingly.

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 impact of the COVID-19 pandemic has negatively affected the oil and natural gas business environment, primarily by causing a reduction in commercial activity and travel worldwide thereby lowering energy demand. This, in turn, resulted in periods of significantly lower market prices for oil, natural gas, and natural gas liquids ("NGLs"). The price environment in 2020 caused many of our operators to reduce their drilling and completion activity on our acreage, which negatively impacts our production volumes. Commodity prices improved in late 2020 and had fully recovered to 2018 levels by July of 2021, reflecting expectations of rising demand as both COVID-19 vaccination rates and global economic activity increased, combined with ongoing crude oil production limits from members of the Organization of the Petroleum Exporting Countries and its broader partners. However, the current price environment remains uncertain as new strains of the virus are driving increases in reported cases and responses to the COVID-19 pandemic continue to evolve. 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. 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 price environment in 2020, including the sharp decline in oil prices that began in March 2020, also caused us to determine that certain depletable units consisting of mature oil producing properties were impaired as of March 31, 2020. Therefore, we recognized impairment of oil and natural gas properties of $51.0 million in the first quarter of 2020. Additionally, the borrowing base under the Credit Facility takes into consideration the estimated loan value of our oil and natural gas properties. Effective November 3, 2020, the borrowing base redetermination reduced the borrowing base from $430.0 million to $400.0 million, and effective April 30, 2021, the borrowing base was reaffirmed at $400.0 million. The next borrowing base redetermination is scheduled for October 2021. 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.

The following table reflects commodity prices as of the last day of each quarter presented:

	2021		2020	
Benchmark Prices[1]	**Second Quarter**	**First Quarter**	**Second Quarter**	**First Quarter**
WTI spot oil price ($/Bbl)	$ 73.52	$ 59.19	$ 39.27	$ 20.51
Henry Hub spot natural gas ($/MMBtu)	3.79	2.52	1.76	1.71

[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. While the rig count has recovered significantly from 2020 levels, this recovery has lagged the recovery in commodity prices as operators focus on greater capital discipline and efficiency.

The following table shows the rig count as of the last day of each quarter presented:

	2021		2020	
U.S. Rotary Rig Count[1]	**Second Quarter**	**First Quarter**	**Second Quarter**	**First Quarter**
Oil	372	324	188	624
Natural gas	98	92	75	102
Other	—	1	2	2
Total	470	417	265	728

[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 will conclude the injection season in October 2021 at 3.6 Tcf, which is 3% lower than the previous five-year average.

The following table shows natural gas storage volumes by region as of the last day of each quarter presented:

	2021		2020	
Region[1]	**Second Quarter**	**First Quarter**	**Second Quarter**	**First Quarter**
East	513	307	639	382
Midwest	623	401	740	476
Mountain	173	112	173	92
Pacific	244	194	304	197
South Central	1,005	749	1,222	840
Total	2,558	1,763	3,078	1,987

[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. 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. 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 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 June 30, 2021 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 June 30, 2021, we have hedged 96% of our available oil and condensate hedge volumes and 84% of our available natural gas hedge volumes for 2021. As of June 30, 2021, we have also hedged 68% of our available oil and condensate hedge volumes and 67% of our natural gas hedge volumes for 2022.

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, non-cash equity-based compensation, and gains and losses on sales of assets. We define Distributable cash flow as Adjusted EBITDA plus or minus amounts for certain non-cash operating activities, 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 June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
	(in thousands)			
Net income (loss)	$ 15,429	$ (8,371)	$ 31,615	$ 67,741
Adjustments to reconcile to Adjusted EBITDA:				
Depreciation, depletion, and amortization	15,796	19,193	31,428	42,375
Impairment of oil and natural gas properties	—	—	—	51,031
Interest expense	1,628	2,964	2,838	7,391
Income tax expense (benefit)	6	126	(151)	162
Accretion of asset retirement obligations	298	278	590	550
Equity–based compensation	3,071	2,474	6,533	(420)
Unrealized (gain) loss on commodity derivative instruments	42,135	55,726	65,494	(25,331)
Adjusted EBITDA	78,363	72,390	138,347	143,499
Adjustments to reconcile to Distributable cash flow:				
Change in deferred revenue	(5)	(7)	(14)	(309)
Cash interest expense	(1,001)	(2,704)	(1,954)	(6,872)
Preferred unit distributions	(5,250)	(5,250)	(10,500)	(10,500)
Restructuring charges[1]	—	—	—	4,815
Distributable cash flow	$ 72,107	$ 64,429	$ 125,879	$ 130,633

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

Results of Operations

Three Months Ended June 30, 2021 Compared to Three Months Ended June 30, 2020

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

	Three Months Ended June 30,			
	2021	2020	Variance	
	(Dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)	860	864	(4)	(0.5) %
Natural gas (MMcf)[1]	15,676	18,090	(2,414)	(13.3) %
Equivalents (MBoe)	3,473	3,879	(406)	(10.5) %
Equivalents/day (MBoe)	38.2	42.6	(4.4)	(10.3) %
Realized prices, without derivatives:				
Oil and condensate ($/Bbl)	$ 62.72	$ 29.42	$ 33.30	113.2 %
Natural gas ($/Mcf)[1]	3.60	1.68	1.92	114.3 %
Equivalents ($/Boe)	$ 31.79	$ 14.37	$ 17.42	121.2 %
Revenue:				
Oil and condensate sales	$ 53,936	$ 25,417	$ 28,519	112.2 %
Natural gas and natural gas liquids sales[1]	56,481	30,311	26,170	86.3 %
Lease bonus and other income	7,505	1,975	5,530	280.0 %
Revenue from contracts with customers	117,922	57,703	60,219	104.4 %
Gain (loss) on commodity derivative instruments	(59,480)	(19,174)	(40,306)	210.2 %
Total revenue	$ 58,442	$ 38,529	$ 19,913	51.7 %
Operating expenses:				
Lease operating expense	$ 3,837	$ 3,293	$ 544	16.5 %
Production costs and ad valorem taxes	9,296	9,555	(259)	(2.7) %
Exploration expense	2	23	(21)	(91.3) %
Depreciation, depletion, and amortization	15,796	19,193	(3,397)	(17.7) %
General and administrative	12,187	11,501	686	6.0 %
Other expense:				
Interest expense	1,628	2,964	(1,336)	(45.1) %

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

Revenue

Total revenue for the quarter ended June 30, 2021 increased compared to the quarter ended June 30, 2020. The increase in total revenue from the corresponding period is due to an increase in oil and condensate sales, natural gas and NGL sales, and lease bonus and other income. The overall increase in total revenue was partially offset by an increase in losses from our commodity derivative instruments.

Oil and condensate sales. Oil and condensate sales increased for the quarter ended June 30, 2021 as compared to the corresponding period in 2020 due to higher realized commodity prices. Our mineral and royalty interest oil and condensate volumes accounted for 92% and 93% of total oil and condensate volumes for the quarters ended June 30, 2021 and 2020, respectively.

Natural gas and natural gas liquids sales. Natural gas and NGL sales increased for the quarter ended June 30, 2021 as compared to the corresponding prior period due to higher realized commodity prices partially offset by lower production volumes. Contributing to this increase was approximately $5.6 million in additional natural gas revenue recognized in the second quarter of 2021 due to realized price differentials during the February 2021 storms exceeding our original projections. The decrease in natural gas and NGL production was driven by decreases in working interest production volumes, primarily within the Haynesville/Bossier play. Mineral and royalty interest production accounted for 83% and 76% of our natural gas volumes for the quarters ended June 30, 2021 and 2020, respectively.

Gain (loss) on commodity derivative instruments. During the second quarter of 2021, we recognized an increase in losses from our commodity derivative instruments compared to the same period in 2020. 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 June 30, 2021, we recognized $17.4 million of realized losses and $42.1 million of unrealized losses from our oil and natural gas commodity contracts, compared to $36.6 million of realized gains and $55.7 million of unrealized losses in the same period in 2020. The unrealized losses on our commodity contracts during the second quarter of 2021 were primarily driven by changes in the forward commodity price curves for oil and natural gas. The unrealized losses for the same period in 2020 were primarily driven by changes in the forward commodity price curves for oil.

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 second quarter of 2021 was higher than the same period in 2020. Leasing activity in the Austin Chalk and proceeds from surface use waivers on our mineral acreage supporting solar development in Mississippi made up the majority of lease bonus and other income for the second quarter of 2021, while a substantial portion of second quarter 2020 activity came from the Permian Basin.

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 increased for the quarter ended June 30, 2021 as compared to the same period in 2020, primarily due to higher nonrecurring service-related expenses, including workovers.

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 June 30, 2021, production costs and ad valorem taxes decreased as compared to the quarter ended June 30, 2020, primarily due to lower ad valorem tax estimates partially offset by higher production taxes due to higher 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 the quarter ended June 30, 2021 and in the corresponding prior period in 2020.

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 June 30, 2021 as compared to the same period in 2020, primarily due to lower production volumes and 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.

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 June 30, 2021, general and administrative expenses increased as compared to the same period in 2020, primarily due to a $1.6 million increase in cash compensation and a $0.5 million increase in equity compensation. The increase in cash compensation was driven by projected outperformance relative to performance targets under our short-term cash incentive plan, and the increase in equity incentive compensation was due to higher costs recognized for performance-based incentive awards due to upward movements in our common unit price period over period. The overall increase was partially offset by a $1.1 million allowance recorded against an outstanding long-term receivable in the prior comparative period with no similar allowance recorded for the quarter ended June 30, 2021.

Interest expense. Interest expense was lower in the second quarter of 2021 relative to the corresponding period in 2020, due to lower average outstanding borrowings under our Credit Facility.

Six Months Ended June 30, 2021 Compared to Six Months Ended June 30, 2020

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

	Six Months Ended June 30,			
	2021	2020	Variance	
	(Dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)	1,689	2,027	(338)	(16.7) %
Natural gas (MMcf)[1]	30,586	36,702	(6,116)	(16.7) %
Equivalents (MBoe)	6,787	8,144	(1,357)	(16.7) %
Equivalents/day (MBoe)	37.5	44.7	(7.2)	(16.1) %
Realized prices, without derivatives:				
Oil and condensate ($/Bbl)	$ 58.09	$ 38.24	$ 19.85	51.9 %
Natural gas ($/Mcf)[1]	3.25	1.82	1.43	78.6 %
Equivalents ($/Boe)	$ 29.10	$ 17.74	$ 11.36	64.0 %
Revenue:				
Oil and condensate sales	$ 98,112	$ 77,510	$ 20,602	26.6 %
Natural gas and natural gas liquids sales[1]	99,370	66,953	32,417	48.4 %
Lease bonus and other income	9,890	6,283	3,607	57.4 %
Revenue from contracts with customers	207,372	150,746	56,626	37.6 %
Gain (loss) on commodity derivative instruments	(87,362)	70,837	(158,199)	NM[2]
Total revenue	$ 120,010	$ 221,583	$ (101,573)	(45.8) %
Operating expenses:				
Lease operating expense	$ 6,501	$ 7,120	$ (619)	(8.7) %
Production costs and ad valorem taxes	21,138	21,931	(793)	(3.6) %
Exploration expense	1,075	24	1,051	4,379.2 %
Depreciation, depletion, and amortization	31,428	42,375	(10,947)	(25.8) %
Impairment of oil and natural gas properties	—	51,031	(51,031)	NM[2]
General and administrative	25,039	23,357	1,682	7.2 %
Other expense:				
Interest expense	2,838	7,391	(4,553)	(61.6) %

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

[2] Not meaningful.

Revenue

Total revenue for the six months ended June 30, 2021 decreased compared to the corresponding prior period. The decrease in total revenue is due to a loss from our commodity derivative instruments for the six months ended June 30, 2021 compared to a gain in the same period in 2020. The overall decrease in total revenue was partially offset by increases in oil and condensate sales, natural gas and NGL sales, and lease bonus and other income.

Oil and condensate sales. Oil and condensate sales during the six months ended June 30, 2021 increased compared to the corresponding prior period due to higher realized commodity prices partially offset by lower production volumes. The decrease in oil and condensate production was primarily driven by lower production volumes in the Permian Basin. Our mineral and royalty interest oil and condensate volumes accounted for 92% of total oil and condensate volumes for both the six months ended June 30, 2021 and 2020.

Natural gas and natural gas liquids sales. Natural gas and NGL sales during the six months ended June 30, 2021 increased compared to the corresponding prior period due to higher realized commodity prices partially offset by lower production volumes. The decrease in natural gas and NGL production was driven by decreases in working interest production volumes, primarily within the Haynesville/Bossier play. Mineral and royalty interest production accounted for 82% and 74% of our natural gas volumes for the six months ended June 30, 2021 and 2020, respectively.

Gain (loss) on commodity derivative instruments. During the six months ended June 30, 2021, we recognized a loss from our commodity derivative instruments compared to a gain for the same period in 2020. In the six months ended June 30, 2021, we recognized $21.9 million of realized losses and $65.5 million of unrealized losses from our oil and natural gas commodity contracts, compared to $45.5 million of realized gains and $25.3 million of unrealized gains in the same period in 2020. The unrealized losses on our commodity contracts during the six months ended June 30, 2021 were primarily driven by changes in the forward commodity price curves for oil and natural gas. The unrealized gains on our commodity contracts during the corresponding period in 2020 were primarily driven by changes in the forward commodity price curves for oil.

Lease bonus and other income. Lease bonus and other income for the six months ended June 30, 2021 was higher than the same period in 2020. Leasing activity in the Austin Chalk and proceeds from surface use waivers on our mineral acreage supporting solar development in Mississippi made up the majority of lease bonus and other income for the six months ended June 30, 2021, while a substantial portion of the activity in the corresponding prior period came from the Permian Basin, Green River Basin, and Bakken/Three Forks.

Operating and Other Expenses

Lease operating expense. Lease operating expense decreased for the six months ended June 30, 2021 as compared to the same period in 2020, primarily due to a decrease in variable costs as a result of lower production from our non-operating working interest properties.

Production costs and ad valorem taxes. For the six months ended June 30, 2021, production costs and ad valorem taxes decreased as compared to the six months ended June 30, 2020, primarily due to lower ad valorem tax estimates partially offset by higher production taxes due to higher commodity prices.

Exploration expense. Exploration expense for the six months ended June 30, 2021 primarily related to a dry hole drilled in the first quarter of 2021. Exploration expense for the six months ended June 30, 2020 was minimal.

Depreciation, depletion, and amortization. Depreciation, depletion, and amortization decreased for the six months ended June 30, 2021 as compared to the same period in 2020, primarily due to lower production volumes and 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 six months ended June 30, 2020, primarily due to declines in future expected realizable net cash flows as a result of lower commodity prices as of the measurement date of March 31, 2020. There were no impairments for the six months ended June 30, 2021.

General and administrative. For the six months ended June 30, 2021, general and administrative expenses increased as compared to the same period in 2020, primarily due to a $0.7 million increase in cash compensation and a $7.0 million increase in equity incentive compensation. The increase in cash compensation was driven by projected outperformance relative to performance targets under our short-term cash incentive plan, and the increase in equity incentive compensation was due to higher costs recognized for performance-based incentive awards resulting from upward movements in our common unit price during the six months ended June 30, 2021 compared to downward movements in our common unit price in the corresponding prior period. The overall increase was partially offset by charges recognized for the six months ended June 30, 2020 that did not recur. This included $4.8 million of restructuring costs associated with workforce reductions in the first quarter of 2020 and a $1.1 million increase in allowance against an outstanding long-term receivable.

Interest expense. Interest expense was lower in the six months ended June 30, 2021 than in the prior period primarily due to 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, proceeds from the issuance of equity and debt, and proceeds from asset sales. 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 June 30, 2021, we had outstanding borrowings of $96.0 million under the Credit Facility.

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

We intend to finance our future acquisitions with cash generated from operations, borrowings from our Credit Facility, proceeds from any future issuances of equity and debt, and proceeds from asset sales. 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.

Cash Flows

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

	Six Months Ended June 30,		
	2021	**2020**	**Change**
	(in thousands)		
Cash flows provided by operating activities	$ 125,579	$ 157,969	$ (32,390)
Cash flows provided by (used in) investing activities	(12,754)	367	(13,121)
Cash flows used in financing activities	(113,578)	(164,855)	51,277

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 for the six months ended June 30, 2021 as compared to the same period of 2020. The decrease was primarily due to net cash paid on settlements of commodity derivative instruments in the six months ended June 30, 2021 compared to net cash received in the same period of 2020. The overall decrease was partially offset by increases in oil and condensate sales and natural gas and NGL sales due to higher realized commodity prices.

Investing Activities. Net cash was used in investing activities in the six months ended June 30, 2021 as compared to net cash provided by investing activities in the same period of 2020. The change was primarily due to cash paid for acquisitions of oil and natural gas properties in the six months ended June 30, 2021 compared to minimal cash paid for acquisitions in the same period of 2020.

Financing Activities. Cash flows used in financing activities decreased for the six months ended June 30, 2021 as compared to the same period of 2020. The decrease was primarily due to lower net repayments under our Credit Facility in the six months ended June 30, 2021 as compared to the corresponding prior period.

Development Capital Expenditures

Our 2021 capital expenditure budget associated with our non-operated working interests is expected to be approximately $5.0 million, net of farmout reimbursements, of which $2.6 million has been invested in the six months ended June 30, 2021. The majority of this capital is anticipated to be spent for working interest participation on test wells in the Austin Chalk play and the remaining 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, 2024. As of June 30, 2021, we had outstanding borrowings of $96.0 million at a weighted-average interest rate of 2.60%.

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. The borrowing base is also adjusted if we terminate our hedge positions or sell oil and natural gas property interests that have a combined value exceeding 5% of the current borrowing base. In these circumstances, the borrowing base will be adjusted by the value attributed to the terminated hedge positions or the oil and natural gas property interests sold in the most recent borrowing base. Effective November 3, 2020, the borrowing base redetermination reduced the borrowing base from $430.0 million to $400.0 million, and effective April 30, 2021, the borrowing base was reaffirmed at $400.0 million. The next semi-annual redetermination is scheduled for October 2021.

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. As of December 31, 2020, the applicable margin for the alternative base rate ranged from 1.00% to 2.00% and the applicable margin for LIBOR ranged from 2.00% to 3.00%, depending on the borrowings outstanding in relation to the borrowing base. As of June 30, 2021, the alternative base rate margin ranged from 1.50% to 2.50% and the LIBOR margin ranged from 2.50% to 3.50%.

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), if the availability under the Credit Facility is less than 10% of the lenders' commitments, or if total debt to EBITDAX is greater than 3.0. 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 June 30, 2021, we were in compliance with all debt covenants.

On March 5, 2021, the U.K. Financial Conduct Authority announced that it intends to stop persuading or compelling banks to submit LIBOR rates after December 31, 2021 for the 1-week and 2-month U.S. dollar settings and after June 30, 2023 for the remaining U.S. dollar settings. Our Credit Facility includes provisions to determine a replacement rate for LIBOR if necessary during its term, based on the secured overnight financing rate published by the Federal Reserve Bank of New York ("SOFR"). We currently do not expect the transition from LIBOR to have a material impact on us.

Contractual Obligations

As of June 30, 2021, there have been no material changes to our contractual obligations previously disclosed in our 2020 Annual Report on Form 10-K.

Off-Balance Sheet Arrangements

As of June 30, 2021, we did not have any material off-balance sheet arrangements.

Critical Accounting Policies and Related Estimates

As of June 30, 2021, there have been no significant changes to our critical accounting policies and related estimates previously disclosed in our 2020 Annual Report on Form 10-K.

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 twelve months ended June 30, 2021 by 10%. This results in an approximate 3% reduction of proved reserve volumes as compared to the unadjusted June 30, 2021 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 June 30, 2021, we had seven counterparties, all of which were rated Baa1 or better by Moody’s and six 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 June 30, 2021, we had $96.0 million of outstanding borrowings under our Credit Facility, bearing interest at a weighted-average interest rate of 2.60%. The impact of a 1% increase in the interest rate on this amount of debt would have resulted in an increase in interest expense, and a corresponding decrease in our results of operations, of $0.5 million for the six months ended June 30, 2021, 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 June 30, 2021 to provide reasonable assurance.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended June 30, 2021 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 2020 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 2020 Annual Report on Form 10-K. These risks are not the only risks that we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may materially adversely affect our business, financial condition or results of operations.

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

Recent Sales of Unregistered Securities

On May 28, 2021, we closed on the purchase of certain mineral interests using 1,087,498 common units valued at $10.8 million to fund a portion of the purchase price.

The issuance of the common units was made in reliance upon an exemption from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereunder. The investors are "accredited investors" (as defined in Regulation D), the investors acquired the common units for investment purposes only and not for resale, and we took appropriate measures to restrict the transfer of the common units issued.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Black Stone Minerals, L.P. (incorporated herein by reference to Exhibit 3.1 to Black Stone Minerals, L.P.'s Registration Statement on Form S-1 filed on March 19, 2015 (SEC File No. 333-202875)).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Black Stone Minerals, L.P. (incorporated herein by reference to Exhibit 3.2 to Black Stone Minerals, L.P.'s Registration Statement on Form S-1 filed on March 19, 2015 (SEC File No. 333-202875)).
3.3	First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated May 6, 2015, by and among Black Stone Minerals GP, L.L.C. and Black Stone Minerals Company, L.P., (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on May 6, 2015 (SEC File No. 001-37362)).
3.4	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated as of April 15, 2016 (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on April 19, 2016 (SEC File No. 001-37362)).
3.5	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated as of November 28, 2017 (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on November 29, 2017 (SEC File No. 001-37362)).
3.6	Amendment No. 3 to First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated as of December 11, 2017 (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on December 12, 2017 (SEC File No. 001-37362)).
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	Fifth 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 April 30, 2021.
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: August 3, 2021	By:	/s/ Thomas L. Carter, Jr.
		Thomas L. Carter, Jr. Chief Executive Officer and Chairman (Principal Executive Officer)
Date: August 3, 2021	By:	/s/ Jeffrey P. Wood
		Jeffrey P. Wood President and Chief Financial Officer (Principal Financial Officer)

Exhibit 31.1

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

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

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

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 3, 2021

/s/ Thomas L. Carter, Jr.

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

Exhibit 31.2

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

I, Jeffrey P. Wood, certify that:

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

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 3, 2021

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

Exhibit 32.1

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

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

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

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

Date: August 3, 2021

/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: August 3, 2021

/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.