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, 2020

OR

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

For the transition period _______________ to _______________

Commission File Number: 001-37362

Black Stone Minerals, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**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 31, 2020, there were 206,737,644 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, 2020	December 31, 2019
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 1,600	$ 8,119
Accounts receivable	45,480	78,214
Commodity derivative assets	45,522	14,790
Assets held for sale	126,491	—
Prepaid expenses and other current assets	2,329	1,168
TOTAL CURRENT ASSETS	221,422	102,291
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, at cost, using the successful efforts method of accounting, includes unproved properties of $946,232 and $1,073,447 at June 30, 2020 and December 31, 2019, respectively	3,156,657	3,302,340
Accumulated depreciation, depletion, amortization, and impairment	(1,947,455)	(1,870,412)
Oil and natural gas properties, net	1,209,202	1,431,928
Other property and equipment, net of accumulated depreciation of $11,963 and $11,622 at June 30, 2020 and December 31, 2019, respectively	1,969	2,300
NET PROPERTY AND EQUIPMENT	1,211,171	1,434,228
DEFERRED CHARGES AND OTHER LONG-TERM ASSETS	6,245	8,689
TOTAL ASSETS	$ 1,438,838	$ 1,545,208
LIABILITIES, MEZZANINE EQUITY, AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 2,870	$ 5,309
Accrued liabilities	10,337	22,702
Commodity derivative liabilities	311	159
Other current liabilities	1,634	1,633
TOTAL CURRENT LIABILITIES	15,152	29,803
LONG–TERM LIABILITIES		
Credit facility	323,000	394,000
Accrued incentive compensation	580	2,110
Commodity derivative liabilities	4,738	18
Asset retirement obligations	16,717	15,653
Other long-term liabilities	4,609	6,820
TOTAL LIABILITIES	364,796	448,404
COMMITMENTS AND CONTINGENCIES (Note 7)		
MEZZANINE EQUITY		
Partners' equity – Series B cumulative convertible preferred units, 14,711 units outstanding at June 30, 2020 and December 31, 2019	298,361	298,361
EQUITY		
Partners' equity – general partner interest	—	—
Partners' equity – common units, 206,709 and 205,960 units outstanding at June 30, 2020 and December 31, 2019, respectively	775,681	798,443
TOTAL EQUITY	775,681	798,443
TOTAL LIABILITIES, MEZZANINE EQUITY, AND EQUITY	$ 1,438,838	$ 1,545,208

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2020	**2019**	**2020**	**2019**
REVENUE				
Oil and condensate sales	$ 25,417	$ 74,072	$ 77,510	$ 131,776
Natural gas and natural gas liquids sales	30,311	53,642	66,953	115,282
Lease bonus and other income	1,975	6,717	6,283	12,362
Revenue from contracts with customers	57,703	134,431	150,746	259,420
Gain (loss) on commodity derivative instruments	(19,174)	29,187	70,837	(11,996)
TOTAL REVENUE	38,529	163,618	221,583	247,424
OPERATING (INCOME) EXPENSE				
Lease operating expense	3,293	3,849	7,120	9,141
Production costs and ad valorem taxes	9,555	14,450	21,931	29,042
Exploration expense	23	304	24	308
Depreciation, depletion, and amortization	19,193	29,725	42,375	57,558
Impairment of oil and natural gas properties	—	—	51,031	—
General and administrative	11,501	14,347	23,357	35,561
Accretion of asset retirement obligations	278	277	550	554
TOTAL OPERATING EXPENSE	43,843	62,952	146,388	132,164
INCOME (LOSS) FROM OPERATIONS	(5,314)	100,666	75,195	115,260
OTHER INCOME (EXPENSE)				
Interest and investment income	3	47	34	93
Interest expense	(2,964)	(5,652)	(7,391)	(11,177)
Other income (expense)	(96)	26	(97)	(72)
TOTAL OTHER EXPENSE	(3,057)	(5,579)	(7,454)	(11,156)
NET INCOME (LOSS)	(8,371)	95,087	67,741	104,104
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 AND SUBORDINATED UNITS	$ (13,621)	$ 89,837	$ 57,241	$ 93,604
ALLOCATION OF NET INCOME (LOSS):				
General partner interest	$ —	$ —	$ —	$ —
Common units	(13,621)	67,718	57,241	69,611
Subordinated units	—	22,119	—	23,993
	$ (13,621)	$ 89,837	$ 57,241	$ 93,604
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON AND SUBORDINATED UNIT:				
Per common unit (basic)	$ (0.07)	$ 0.45	$ 0.28	$ 0.54
Weighted average common units outstanding (basic)	206,707	150,101	206,669	129,873
Per subordinated unit (basic)	$ —	$ 0.39	$ —	$ 0.32
Weighted average subordinated units outstanding (basic)	—	56,104	—	76,105
Per common unit (diluted)	$ (0.07)	$ 0.44	$ 0.28	$ 0.54
Weighted average common units outstanding (diluted)	206,707	165,070	206,669	129,873
Per subordinated unit (diluted)	$ —	$ 0.39	$ —	$ 0.32
Weighted average subordinated units outstanding (diluted)	—	56,104	—	76,105

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 EQUITY
(Unaudited)
(In thousands)

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

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,	
	2020	**2019**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income (loss)	$ 67,741	$ 104,104
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, and amortization	42,375	57,558
Impairment of oil and natural gas properties	51,031	—
Accretion of asset retirement obligations	550	554
Amortization of deferred charges	519	516
(Gain) loss on commodity derivative instruments	(70,837)	11,996
Net cash (paid) received on settlement of commodity derivative instruments	45,506	4,674
Equity-based compensation	(420)	13,039
Exploratory dry hole expense	—	3
Changes in operating assets and liabilities:		
Accounts receivable	33,544	17,212
Prepaid expenses and other current assets	(1,163)	(976)
Accounts payable, accrued liabilities, and other	(10,790)	(7,405)
Settlement of asset retirement obligations	(87)	(299)
NET CASH PROVIDED BY OPERATING ACTIVITIES	157,969	200,976
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisitions of oil and natural gas properties	(28)	(40,676)
Additions to oil and natural gas properties	(4,146)	(50,121)
Additions to oil and natural gas properties leasehold costs	(782)	(871)
Purchases of other property and equipment	(10)	(2,152)
Proceeds from the sale of oil and natural gas properties	1,266	320
Proceeds from farmouts of oil and natural gas properties	4,067	47,487
NET CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES	367	(46,013)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from issuance of common units, net of offering costs	—	(43)
Distributions to common and subordinated unitholders	(78,320)	(152,030)
Distributions to Series B cumulative convertible preferred unitholders	(10,500)	(10,500)
Distribution equivalents paid	—	(2,982)
Repurchases of common units	(5,035)	(16,916)
Borrowings under credit facility	89,000	172,500
Repayments under credit facility	(160,000)	(146,500)
NET CASH USED IN FINANCING ACTIVITIES	(164,855)	(156,471)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(6,519)	(1,508)
CASH AND CASH EQUIVALENTS – beginning of the period	8,119	5,414
CASH AND CASH EQUIVALENTS – end of the period	$ 1,600	$ 3,906
SUPPLEMENTAL DISCLOSURE		
Interest paid	$ 6,934	$ 10,618

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

NOTE 1 - BUSINESS AND BASIS OF PRESENTATION

Description of the Business

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

Basis of Presentation

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

The unaudited interim consolidated financial statements include the consolidated results of the Partnership. The results of operations for the six months ended June 30, 2020 are not necessarily indicative of the results to be expected for the full year.

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

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

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

Segment Reporting

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

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Significant Accounting Policies

Significant accounting policies are disclosed in the Partnership’s 2019 Annual Report on Form 10-K. There have been no changes in such policies or the application of such policies during the six months ended June 30, 2020.

Accounts Receivable

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

	June 30, 2020	December 31, 2019
	(in thousands)	
Accounts receivable:		
Revenues from contracts with customers	$ 40,837	$ 71,022
Other	4,643	7,192
Total accounts receivable	$ 45,480	$ 78,214

Recent Accounting Pronouncements

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

NOTE 3 - OIL AND NATURAL GAS PROPERTIES

Assets Held for Sale

In June 2020, the Partnership announced it had entered into two separate agreements to sell certain mineral and royalty properties in the Permian Basin. These transactions subsequently closed in July 2020 for total proceeds, after closing adjustments, of $150.1 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 to a private buyer for gross proceeds of approximately $55 million ("Divestiture A"). 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 to Pegasus Resources, LLC, a portfolio company of EnCap Investments, for gross proceeds of approximately $100 million ("Divestiture B"). The book value of the assets divested through these transactions are classified as held for sale in the consolidated balance sheet as of June 30, 2020.

Assets held for sale consisted of the following as of June 30, 2020:

	Divestiture A	Divestiture B	Total
		(in thousands)	
Accounts Receivable	$ 227	$ —	$ 227
Oil and natural gas properties			
Unproved properties	50,985	67,292	118,277
Proved properties, net	2,274	5,713	7,987
Total Assets Held for Sale	$ 53,486	$ 73,005	$ 126,491

The assets held for sale as of June 30, 2020 do not qualify for discontinued operations as they do not represent a strategic shift that will have a major effect on the Partnership's operations or financial results.

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.

2020 Acquisitions

The Partnership had no acquisition activity during the six months ended June 30, 2020.

2019 Acquisitions

During the year ended December 31, 2019, the Partnership closed on multiple acquisitions of mineral and royalty interests for total consideration of $44.0 million. Acquisitions that were considered business combinations were primarily located in the Permian Basin. These acquisitions were funded with borrowings under the Credit Facility (as defined in Note 6 - Credit Facility) and funds from operating activities. Acquisition related costs of less than $0.1 million were expensed and included in the General and administrative line item of the consolidated statement of operations for the year ended December 31, 2019. The following table summarizes these acquisitions:

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

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

Farmout Agreements

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

Canaan Farmout

On February 21, 2017, the Partnership announced that it had entered into a farmout agreement with Canaan Resource Partners ("Canaan") which covers certain Haynesville and Bossier shale acreage in San Augustine County, Texas operated by XTO Energy Inc., a subsidiary of Exxon Mobil Corporation. The Partnership has an approximate 50% working interest in the acreage and is the largest mineral owner. A total of 20 wells were drilled over an initial phase, beginning with wells spud after January 1, 2017. Canaan elected to participate in an additional phase that began in September 2018 and continues for the lesser of 2 years or until 20 wells have been drilled. As of June 30, 2020, a total of 17 wells have been drilled during the second phase. After the completion of the second phase, Canaan will have the option to elect to participate in a similar third phase. During the first three phases of the agreement, Canaan commits on a phase-by-phase basis and funds 80% of the Partnership's drilling and completion costs and is assigned 80% of the Partnership's working interests in such wells (40% working interest on an 8/8ths basis) as the wells are drilled. After the third phase, Canaan can earn 40% of the Partnership’s working interest (20% working interest on an 8/8ths basis) in additional wells drilled in the area by continuing to fund 40% of the Partnership's costs for those wells on a well-by-well basis. The Partnership receives an overriding royalty interest (“ORRI”) before payout and an increased ORRI after payout on all wells drilled under the agreement.

Pivotal Farmout

On November 21, 2017, the Partnership entered into a farmout agreement with Pivotal Petroleum Partners (“Pivotal”), a portfolio company of Tailwater Capital, LLC. The farmout agreement covers substantially all of the Partnership's remaining working interests under active development in the Shelby Trough area of East Texas, targeting the Haynesville and Bossier shale acreage (after giving effect to the Canaan Farmout), until November 2025. Pivotal will earn the Partnership's remaining working interest in wells operated by XTO Energy Inc. in San Augustine County, Texas not covered by the Canaan Farmout (10% working interest on an 8/8th basis), as well as 100% of the Partnership's working interests (ranging from approximately 12.5% to 25% on an 8/8ths basis) in wells operated by BPX Energy in San Augustine and Angelina counties, Texas. Initially, Pivotal is obligated to fund the development of up to 80 wells, in designated well groups, across several development areas and then has options to continue funding the Partnership's working interest across those areas for the duration of the farmout agreement. Once Pivotal achieves a specified payout for a designated well group, the Partnership will obtain a majority of the original working interest in such well group. As of June 30, 2020, a total of 68 wells have been drilled in the contract area. The Partnership's development agreement with BPX Energy terminated in 2019 with respect to the majority of the Partnership's acreage covered by the farmout agreement with Pivotal. As such, Pivotal retains minimal rights or obligations related to the farmout for that area. In the second quarter of 2020, the Partnership entered into a development agreement with Aethon Energy ("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 begins in the third quarter of 2020, increasing to a minimum of 15 wells per year beginning with the third program year. The Partnership remains engaged with Pivotal around farmout opportunities in the area forfeited by BPX Energy, including the acreage covered by the Aethon development agreement.

From the inception of the farmout agreements through June 30, 2020, the Partnership has received $90.3 million and $119.1 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, 2020 and December 31, 2019, $0.1 million and $1.7 million, respectively, was included in the Other long-term liabilities line item of the consolidated balance sheets for reimbursements received associated with farmed-out working interests not yet assigned to Canaan and Pivotal.

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 as of March 31, 2020.

The Partnership recognized no impairment of oil and natural gas properties for the three months ended June 30, 2020 and $51.0 million of impairment of oil and natural gas properties for the six months ended June 30, 2020. No impairment of oil and natural gas properties was recognized during 2019. See Note 5 - Fair Value Measurements for further discussion.

NOTE 4 - COMMODITY DERIVATIVE FINANCIAL INSTRUMENTS

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

As of June 30, 2020, the Partnership’s open derivative contracts consisted of fixed-price swap contracts and costless collar contracts. A fixed-price swap contract between the Partnership and the counterparty specifies a fixed commodity price and a future settlement date. A costless collar contract between the Partnership and the counterparty specifies a floor and a ceiling commodity price and a future settlement date. The Partnership has not designated any of its contracts as fair value or cash flow hedges. Accordingly, the changes in the fair value of the contracts are included in the consolidated statement of operations in the period of the change. All derivative gains and losses from the Partnership’s derivative contracts have been recognized in revenue in the Partnership's accompanying consolidated statements of operations. Derivative instruments that have not yet been settled in cash are reflected as either derivative assets or liabilities in the Partnership’s accompanying consolidated balance sheets as of June 30, 2020 and December 31, 2019. See Note 5 - Fair Value Measurements for further discussion.

The Partnership's derivative contracts expose it to credit risk in the event of nonperformance by counterparties that may adversely impact the fair value of the Partnership's commodity derivative assets. While the Partnership does not require its derivative contract counterparties to post collateral, the Partnership does evaluate the credit standing of such counterparties as deemed appropriate. This evaluation includes reviewing a counterparty’s credit rating and latest financial information. As of June 30, 2020, the Partnership had nine counterparties, all of which are rated Baa1 or better by Moody’s and are lenders under the Credit Facility.

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

		June 30, 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	$ 49,258	$ (3,736)	$ 45,522
Long-term asset	Deferred charges and other long-term assets	610	(531)	79
Total assets		$ 49,868	$ (4,267)	$ 45,601
Liabilities:				
Current liability	Commodity derivative liabilities	$ 4,047	$ (3,736)	$ 311
Long-term liability	Commodity derivative liabilities	5,269	(531)	4,738
Total liabilities		$ 9,316	$ (4,267)	$ 5,049

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

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:

	Three Months Ended June 30,		Six Months Ended June 30,	
Derivatives not designated as hedging instruments	2020	2019	2020	2019
	(in thousands)			
Beginning fair value of commodity derivative instruments	$ 96,278	$ 5,112	$ 15,221	$ 48,038
Gain (loss) on oil derivative instruments	(21,647)	7,905	56,164	(31,356)
Gain (loss) on natural gas derivative instruments	2,473	21,282	14,673	19,360
Net cash paid (received) on settlements of oil derivative instruments	(26,776)	1,745	(28,317)	(2,810)
Net cash paid (received) on settlements of natural gas derivative instruments	(9,776)	(4,676)	(17,189)	(1,864)
Net change in fair value of commodity derivative instruments	(55,726)	26,256	25,331	(16,670)
Ending fair value of commodity derivative instruments	$ 40,552	$ 31,368	$ 40,552	$ 31,368

The Partnership had the following open derivative contracts for oil as of June 30, 2020:

			Range (Per Bbl)	
Period and Type of Contract	Volume (Bbl)	Weighted Average Price (Per Bbl)	Low	High
Oil Swap Contracts:				
2020				
Second Quarter	210,000	$ 57.32	$ 54.92	$ 58.65
Third Quarter	630,000	57.32	54.92	58.65
Fourth Quarter	630,000	57.32	54.92	58.65
2021				
First Quarter	480,000	$ 36.18	$ 32.64	$ 37.92
Second Quarter	480,000	36.18	32.64	37.92
Third Quarter	480,000	36.18	32.64	37.92
Fourth Quarter	480,000	36.18	32.64	37.92

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

The Partnership had the following open derivative contracts for natural gas as of June 30, 2020:

Period and Type of Contract	Volume (MMBtu)	Weighted Average Price (Per MMBtu)		Range (Per MMBtu) Low		High	
Natural Gas Swap Contracts:							
2020							
Third Quarter	10,120,000	$	2.69	$	2.55	$	2.74
Fourth Quarter	10,120,000		2.69		2.55		2.74
2021							
First Quarter	7,200,000	$	2.60	$	2.52	$	2.72
Second Quarter	7,280,000		2.60		2.52		2.72
Third Quarter	7,360,000		2.60		2.52		2.72
Fourth Quarter	7,360,000		2.60		2.52		2.72

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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

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, 2020					
Financial Assets					
Commodity derivative instruments	$ —	$ 49,868	$ —	$ (4,267)	$ 45,601
Financial Liabilities					
Commodity derivative instruments	$ —	$ 9,316	$ —	$ (4,267)	$ 5,049
As of December 31, 2019					
Financial Assets					
Commodity derivative instruments	$ —	$ 19,741	$ —	$ (4,343)	$ 15,398
Financial Liabilities					
Commodity derivative instruments	$ —	$ 4,520	$ —	$ (4,343)	$ 177

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

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

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

Oil and natural gas properties are measured at fair value on a non-recurring basis using the income approach when assessing for impairment. The factors used to determine fair value include estimates of proved reserves, future commodity prices, timing of future production, operating costs, future capital expenditures, and a risk-adjusted discount rate. The Partnership estimated the fair value of the impaired properties 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, 2020				
Impaired oil and natural gas properties	$ —	$ —	$ —	$ —
Three Months Ended June 30, 2019				
Impaired oil and natural gas properties	$ —	$ —	$ —	$ —
Six Months Ended June 30, 2020				
Impaired oil and natural gas properties	$ —	$ —	$ 2,044	$ 51,031
Six Months Ended June 30, 2019				
Impaired oil and natural gas properties	$ —	$ —	$ —	$ —

The Partnership’s estimates of fair value have been determined at discrete points in time based on relevant market data. These estimates involve uncertainty, particularly in the current volatile market, and cannot be determined with precision. Changes to these estimates, particularly related to economic reserves, future commodity prices, and timing of future production could result in additional impairment charges in the future. There were no significant changes in valuation techniques or related inputs as of June 30, 2020 or December 31, 2019.

NOTE 6 - CREDIT FACILITY

The Partnership maintains a senior secured revolving credit agreement, as amended (the “Credit Facility”). The Credit Facility has an aggregate maximum credit amount of $1.0 billion and terminates on November 1, 2022. The commitment of the lenders equals the lesser of the aggregate maximum credit amount and the borrowing base. The amount of the borrowing base is redetermined semi-annually, usually in October and April, and is derived from the value of the Partnership’s oil and natural gas properties as determined by the lender syndicate using pricing assumptions that often differ from the current market for future prices. The Partnership and the lenders (at the direction of two-thirds of the lenders) each have discretion to request a borrowing base redetermination one time between scheduled redeterminations. Effective October 23, 2019 the borrowing base redetermination reduced the borrowing base from $675.0 million to $650.0 million and, effective May 1, 2020, the borrowing base was further reduced to $460.0 million. Effective July 21, 2020, in connection with the closing of the Partnership's two asset sales in the Permian Basin, the borrowing base was further reduced to $430.0 million.

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

The weighted-average interest rate of the Credit Facility was 2.43% and 4.05% as of June 30, 2020 and December 31, 2019, respectively. Accrued interest is payable at the end of each calendar quarter or at the end of each interest period, unless the interest period is longer than 90 days, in which case interest is payable at the end of every 90-day period. In addition, a commitment fee is payable at the end of each calendar quarter based on either a rate of 0.375% if the borrowing base utilization percentage is less than 50%, or 0.500% if the borrowing base utilization percentage is equal to or greater than 50%. The Credit Facility is secured by substantially all of the Partnership’s oil and natural gas production and assets.

The Credit Facility contains various limitations on future borrowings, leases, hedging, and sales of assets. Additionally, the Credit Facility requires the Partnership to maintain a current ratio of not less than 1.0:1.0 and a ratio of total debt to EBITDAX (Earnings before Interest, Taxes, Depreciation, Amortization, and Exploration) of not more than 3.5:1.0. As of June 30, 2020, the Partnership was in compliance with all financial covenants in the Credit Facility.

The aggregate principal balance outstanding was $323.0 million and $394.0 million at June 30, 2020 and December 31, 2019, respectively. The unused portion of the available borrowings under the Credit Facility were $137.0 million and $256.0 million at June 30, 2020 and December 31, 2019, respectively.

NOTE 7 - COMMITMENTS AND CONTINGENCIES

Environmental Matters

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

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

Put Option Related to Noble Acquisition

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

Litigation

From time to time, the Partnership is involved in legal actions and claims arising in the ordinary course of business. The Partnership believes existing claims as of June 30, 2020 will be resolved without material adverse effect on the Partnership’s financial condition or operations.

NOTE 8 - INCENTIVE COMPENSATION

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2020	2019	2020	2019
	(in thousands)			
Cash—short and long-term incentive plans	$ 506	$ 1,471	$ 1,469	$ 3,243
Equity-based compensation—restricted common units	1,126	2,591	2,411	5,610
Equity-based compensation—restricted performance units[1]	1,098	637	(3,559)	6,257
Board of Directors incentive plan	250	587	728	1,172
Total incentive compensation expense	$ 2,980	$ 5,286	$ 1,049	$ 16,282

[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, 2020 and December 31, 2019. The Series B cumulative convertible preferred units are classified as mezzanine equity on the consolidated balance sheets since certain provisions of redemption are outside the control of the Partnership.

NOTE 10 - EARNINGS PER UNIT

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

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

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2020	2019	2020	2019
	(in thousands, except per unit amounts)			
NET INCOME (LOSS)	$ (8,371)	$ 95,087	$ 67,741	$ 104,104
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 AND SUBORDINATED UNITS	(13,621)	89,837	57,241	93,604
ALLOCATION OF NET INCOME (LOSS):				
General partner interest	$ —	$ —	$ —	$ —
Common units	(13,621)	67,718	57,241	69,611
Subordinated units	—	22,119	—	23,993
	$ (13,621)	$ 89,837	$ 57,241	$ 93,604
Weighted average common units outstanding:				
Weighted average common units outstanding (basic)	206,707	150,101	206,669	129,873
Effect of dilutive securities	—	14,969	—	—
Weighted average common units outstanding (diluted)	206,707	165,070	206,669	129,873
Weighted average subordinated units outstanding:				
Weighted average subordinated units outstanding (basic)	—	56,104	—	76,105
Effect of dilutive securities	—	—	—	—
Weighted average subordinated units outstanding (diluted)	—	56,104	—	76,105
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON AND SUBORDINATED UNIT:				
Per common unit (basic)	$ (0.07)	$ 0.45	$ 0.28	$ 0.54
Per subordinated unit (basic)	—	0.39	—	0.32
Per common unit (diluted)[1]	(0.07)	0.44	0.28	0.54
Per subordinated unit (diluted)	—	0.39	—	0.32

[1] For the three months ended June 30, 2019, diluted net income (loss) attributable to common units included distributions on Series B cumulative convertible preferred units of $5.3 million.

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,	
	2020	2019	2020	2019
	(in thousands)			
Potentially dilutive securities (common units):				
Series B cumulative convertible preferred units on an as-converted basis	14,969	—	14,969	14,969

NOTE 11 - COMMON AND SUBORDINATED UNITS

Common and Subordinated Units

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

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

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

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2020	2019	2020	2019
DISTRIBUTIONS DECLARED AND PAID:				
Per common unit	$ 0.0800	$ 0.3700	$ 0.3800	$ 0.7400
Per subordinated unit	—	0.3700	—	0.7400

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, 2020. As of June 30, 2020, the Partnership has repurchased $4.2 million in common units under the repurchase program since inception. The repurchase program is funded from the Partnership's cash on hand or availability on the Credit Facility. Any repurchased units are canceled.

NOTE 12 - SUBSEQUENT EVENTS

On July 27, 2020, the Board approved a distribution for the three months ended June 30, 2020 of $0.15 per common unit. Distributions will be payable on August 21, 2020 to unitholders of record at the close of business on August 14, 2020.

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

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

Cautionary Note Regarding Forward-Looking Statements

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

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

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

For additional information regarding known material factors that could cause our actual results to differ from our projected results, please see “Risk Factors” in our 2019 Annual Report on Form 10-K and in this Quarterly Report on Form 10-Q.

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

Overview

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

As of June 30, 2020, our mineral and royalty interests were located in 41 states in the continental United States, including all of the major onshore producing basins. These non-cost-bearing interests include ownership in approximately 69,000 producing wells. We also own non-operated working interests, a significant portion of which are on our positions where we also have a mineral and royalty interest. We recognize oil and natural gas revenue from our mineral and royalty and non-operated working interests in producing wells when control of the oil and natural gas produced is transferred to the customer and collectability of the sales price is reasonably assured. Our other sources of revenue include mineral lease bonus and delay rentals, which are recognized as revenue according to the terms of the lease agreements.

Recent Developments

Asset Sales

In July 2020, we closed our two previously announced transactions to sell certain mineral and royalty properties in the Permian Basin for total proceeds, after closing adjustments, of $150.1 million. The proceeds were used to reduce outstanding borrowings under our Credit Facility.

One of these transactions, effective May 1, 2020, involved the sale of our mineral and royalty interests in specific tracts in Midland County, Texas to a private buyer for gross proceeds of approximately $55 million. The other transaction, effective July 1, 2020, involved the sale of an undivided interest across parts of our Delaware Basin and Midland Basin positions to Pegasus Resources, LLC, a portfolio company of EnCap Investments, for gross proceeds of approximately $100 million. We estimate the production associated with the properties sold, in total, to be approximately 1,800 Boe per day.

COVID-19 Pandemic and Commodity Prices

The COVID-19 pandemic has adversely affected the global economy, disrupted global supply chains and created significant volatility in the financial markets. In addition, the pandemic has resulted in travel restrictions, business closures and the institution of quarantining and other restrictions on movement in many communities. To protect the health and well-being of our workforce in the wake of COVID-19, we have implemented remote work arrangements for all employees. We do not expect these arrangements to impact our ability to maintain operations. We will continue to prioritize the health and safety of our workforce when employees return to the office through frequent cleaning of common spaces, appropriate social distancing measures, and other best practices as recommended by state and local officials.

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

The current price environment, 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, which takes into consideration the estimated loan value of our oil and natural gas properties, was reduced from $650.0 million to $460.0 million, effective May 1, 2020. Effective July 21, 2020, in connection with the closing of our two asset sales in the Permian Basin, the borrowing base was further reduced to $430.0 million. In a prolonged period of low commodity prices, we may be required to impair additional properties and the borrowing base under our Credit Facility could be further reduced. In light of the challenging business environment and uncertainty caused by the pandemic, the board of directors of our general partner (the "Board") also approved a reduction in the quarterly distribution for the first quarter of 2020 to increase the amount of retained free cash flow for debt reduction and balance sheet protection. The Board approved an increase in the quarterly distribution for the second quarter of 2020 but the distribution remains below 2019 levels.

Shelby Trough Update

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

On June 10, 2020, we entered into a new incentive agreement with XTO Energy Inc. ("XTO") with respect to certain drilled but uncompleted wells ("DUCs") in our Shelby Trough acreage in San Augustine County, Texas. The agreement allows for royalty relief on 13 existing DUCs if XTO completes and turns the wells to sales by March 31, 2021, and complements the recent development agreement with Aethon covering our Shelby Trough acreage in Angelina County towards our goal of reviving volume growth from the area.

Common Unit Repurchase Program

On November 5, 2018, the Board authorized the repurchase of up to $75.0 million in common units. The repurchase program authorizes us to make repurchases on a discretionary basis as determined by management, subject to market conditions, applicable legal requirements, available liquidity, and other appropriate factors. All or a portion of any repurchases may be made under a Rule 10b5-1 plan, which would permit common units to be purchased when we might otherwise be precluded from doing so under applicable laws. The repurchase program does not obligate us to acquire any particular amount of common units and may be modified or suspended at any time and could be terminated prior to completion. We will periodically report the number of common units repurchased. We made no repurchases under this program for the six months ended June 30, 2020. As of June 30, 2020, we have repurchased $4.2 million in common units under the repurchase program since inception. The repurchase program is funded from our cash on hand or availability under the Credit Facility. Any repurchased units are canceled.

Business Environment

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

COVID-19 Pandemic and Market Conditions

The COVID-19 pandemic and related economic repercussions have resulted in a significant reduction in demand for and prices of oil, natural gas and NGLs. In the first quarter of 2020 and into the second quarter of 2020, oil prices fell sharply and dramatically, due in part to significantly decreased demand as a result of the COVID-19 pandemic and the announcement by Saudi Arabia of a significant increase in its maximum oil production capacity as well as the announcement by Russia that previously agreed upon oil production cuts between members of the Organization of the Petroleum Exporting Countries and its broader partners (“OPEC+”) would expire on April 1, 2020, and the ensuing expiration thereof. Agreed-upon production cuts by OPEC+ along with declining U.S. production have helped to correct the supply and demand imbalance; however, these reductions are not expected to be enough in the near-term to offset the significant inventory build caused by demand destruction from the COVID-19 pandemic in the first half of 2020. We expect these market conditions to result in a continued decline in drilling activity as operators revise their capital budgets downward and adjust their operations, including shutting in producing wells, in response to lower commodity prices. Given the dynamic nature of these events, we cannot reasonably estimate the period of time that the COVID-19 pandemic and related market conditions will persist.

Commodity Prices and Demand

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

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

Benchmark Prices[1]	**June 30, 2020**	**March 31, 2020**	**June 30, 2019**	**March 31, 2019**
WTI spot oil price ($/Bbl)	$ 39.27	$ 20.51	$ 58.20	$ 60.19
Henry Hub spot natural gas ($/MMBtu)	$ 1.76	$ 1.71	$ 2.42	$ 2.73

[1] Source: EIA

Rig Count

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

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

U.S. Rotary Rig Count[1]	June 30, 2020	March 31, 2020	June 30, 2019	March 31, 2019
Oil	188	624	793	816
Natural gas	75	102	173	190
Other	2	2	1	—
Total	265	728	967	1,006

[1] Source: Baker Hughes Incorporated

Natural Gas Storage

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

Historically, natural gas supply and demand fluctuates on a seasonal basis. From April to October, when the weather is warmer and natural gas demand is lower, natural gas storage levels generally increase. From November to March, storage levels typically decline as utility companies draw natural gas from storage to meet increased heating demand due to colder weather. In order to maintain sufficient storage levels for increased seasonal demand, a portion of natural gas production during the summer months must be used for storage injection. The portion of production used for storage varies from year to year depending on the demand from the previous winter and the demand for electricity used for cooling during the summer months. The EIA estimates that natural gas inventories will conclude the injection season on October 31, 2020 at 4.0 Tcf, or 8% higher than the previous five-year average.

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

Region[1]	June 30, 2020	March 31, 2020	June 30, 2019	March 31, 2019
East	639	382	526	210
Midwest	740	476	568	241
Mountain	173	92	134	64
Pacific	304	197	255	113
South Central	1,222	840	907	502
Total	3,078	1,987	2,390	1,130

[1] Source: EIA

How We Evaluate Our Operations

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

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

Volumes of Oil and Natural Gas Produced

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

Commodity Prices

Factors Affecting the Sales Price of Oil and Natural Gas

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

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

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

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

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

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

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

Hedging

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

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

We may employ contractual arrangements other than fixed-price swap contracts and costless collar contracts in the future to mitigate the impact of price fluctuations. If commodity prices decline in the future, our hedging contracts will partially mitigate the effect of lower prices on our future revenue. Our open oil and natural gas derivative contracts as of June 30, 2020 are detailed in Note 4 - Commodity Derivative Financial Instruments to our unaudited consolidated financial statements included elsewhere in this Quarterly Report.

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

We are allowed to hedge up to 90% of such volumes for the first 24 months, 70% for months 25 through 36, and 50% for months 37 through 48. As of June 30, 2020, we have hedged all of our available oil and condensate hedge volumes and 83% of our available natural gas hedge volumes for 2020. As of June 30, 2020, we have also hedged 70% of our available oil and condensate hedge volumes and 57% of our available natural gas hedge volumes for 2021.

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

Non-GAAP Financial Measures

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

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

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

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2020	2019	2020	2019
	(in thousands)			
Net income (loss)	$ (8,371)	$ 95,087	$ 67,741	$ 104,104
Adjustments to reconcile to Adjusted EBITDA:				
Depreciation, depletion, and amortization	19,193	29,725	42,375	57,558
Impairment of oil and natural gas properties	—	—	51,031	—
Interest expense	2,964	5,652	7,391	11,177
Income tax expense (benefit)	126	35	162	166
Accretion of asset retirement obligations	278	277	550	554
Equity–based compensation	2,474	3,816	(420)	13,039
Unrealized (gain) loss on commodity derivative instruments	55,726	(26,256)	(25,331)	16,670
Adjusted EBITDA	72,390	108,336	143,499	203,268
Adjustments to reconcile to Distributable cash flow:				
Change in deferred revenue	(7)	294	(309)	(10)
Cash interest expense	(2,704)	(5,392)	(6,872)	(10,661)
Estimated replacement capital expenditures[1]	—	—	—	(2,750)
Preferred unit distributions	(5,250)	(5,250)	(10,500)	(10,500)
Restructuring charges[2]	—	—	4,815	—
Distributable cash flow	$ 64,429	$ 97,988	$ 130,633	$ 179,347

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

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

Results of Operations

Three Months Ended June 30, 2020 Compared to Three Months Ended June 30, 2019

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

	Three Months Ended June 30,			
	2020	2019	Variance	
	(Dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)	864	1,316	(452)	(34.3)%
Natural gas (MMcf)[1]	18,090	20,594	(2,504)	(12.2)%
Equivalents (MBoe)	3,879	4,748	(869)	(18.3)%
Equivalents/day (MBoe)	42.6	52.2	(9.6)	(18.4)%
Realized prices, without derivatives:				
Oil and condensate ($/Bbl)	$ 29.42	$ 56.30	$ (26.88)	(47.7)%
Natural gas ($/Mcf)[1]	1.68	2.60	(0.92)	(35.4)%
Equivalents ($/Boe)	$ 14.37	$ 26.90	$ (12.53)	(46.6)%
Revenue:				
Oil and condensate sales	$ 25,417	$ 74,072	$ (48,655)	(65.7)%
Natural gas and natural gas liquids sales[1]	30,311	53,642	(23,331)	(43.5)%
Lease bonus and other income	1,975	6,717	(4,742)	(70.6)%
Revenue from contracts with customers	57,703	134,431	(76,728)	(57.1)%
Gain (loss) on commodity derivative instruments	(19,174)	29,187	(48,361)	NM[2]
Total revenue	$ 38,529	$ 163,618	$ (125,089)	(76.5)%
Operating expenses:				
Lease operating expense	$ 3,293	$ 3,849	$ (556)	(14.4)%
Production costs and ad valorem taxes	9,555	14,450	(4,895)	(33.9)%
Exploration expense	23	304	(281)	(92.4)%
Depreciation, depletion, and amortization	19,193	29,725	(10,532)	(35.4)%
General and administrative	11,501	14,347	(2,846)	(19.8)%
Other expense:				
Interest expense	2,964	5,652	(2,688)	(47.6)%

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

[2] Not meaningful.

Revenue

Total revenue for the quarter ended June 30, 2020 decreased compared to the quarter ended June 30, 2019. The decrease in total revenue from the corresponding period is due to a loss on our commodity derivative instruments in the second quarter of 2020 compared to a gain in the second quarter of 2019, a decrease in oil and condensate sales and natural gas and NGL sales as a result of lower realized commodity prices and lower production volumes, and a decrease in lease bonus and other income.

Oil and condensate sales. Oil and condensate sales decreased for the quarter ended June 30, 2020 as compared to the corresponding period in 2019 due to lower realized commodity prices and lower production volumes. The decrease in oil and condensate production was primarily driven by production volume decreases in the Permian Basin and Bakken/Three Forks.

Our mineral and royalty interest oil and condensate volumes accounted for 93% of total oil and condensate volumes for both quarters ended June 30, 2020 and 2019.

Natural gas and natural gas liquids sales. Natural gas and NGL sales decreased for the quarter ended June 30, 2020 as compared to the corresponding prior period due to lower realized commodity prices and lower production volumes. The decrease in natural gas and NGL production was primarily driven by production volume decreases in the Haynesville/Bossier play. Mineral and royalty interest production accounted for 76% and 70% of our natural gas volumes for the quarters ended June 30, 2020 and 2019, respectively.

Gain (loss) on commodity derivative instruments. During the second quarter of 2020, we recognized a loss from our commodity derivative instruments compared to a gain in the same period in 2019. Cash settlements we receive represent realized gains, while cash settlements we pay represent realized losses related to our commodity derivative instruments. In addition to cash settlements, we also recognize fair value changes on our commodity derivative instruments in each reporting period. The changes in fair value result from new positions and settlements that may occur during each reporting period, as well as the relationships between contract prices and the associated forward curves. For the three months ended June 30, 2020, we recognized $36.6 million of realized gains and $55.7 million of unrealized losses from our oil and natural gas commodity contracts, compared to $2.9 million of realized gains and $26.3 million of unrealized gains in the same period in 2019. The unrealized losses on our commodity contracts during the second quarter of 2020 was primarily driven by changes in the forward commodity price curve for oil. The unrealized gains in the same period in 2019 were primarily driven by changes in the forward commodity price curve for natural gas.

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 2020 was lower than the same period in 2019. Leasing activity in the Permian Basin made up the majority of lease bonus revenue in the second quarter of 2020, while a substantial portion of second quarter 2019 activity came from the Permian Basin and the Wilcox.

Operating Expenses

Lease operating expense. Lease operating expense includes recurring expenses associated with our non-operated working interests necessary to produce hydrocarbons from our oil and natural gas wells, as well as certain nonrecurring expenses, such as well repairs. Lease operating expense decreased for the quarter ended June 30, 2020 as compared to the same period in 2019, primarily due to lower nonrecurring service-related expenses, including workovers, as well as a decrease in variable costs as a result of lower production from our non-operating working interest properties.

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, 2020, production costs and ad valorem taxes decreased as compared to the quarter ended June 30, 2019, primarily as a result of lower commodity prices and lower production volumes.

Exploration expense. Exploration expense typically consists of dry-hole expenses, delay rentals, and geological and geophysical costs, including seismic costs, and is expensed as incurred under the successful efforts method of accounting. Exploration expense was minimal for each of the three months ended June 30, 2020 and 2019.

Depreciation, depletion, and amortization. Depletion is the amount of cost basis of oil and natural gas properties attributable to the volume of hydrocarbons extracted during a period, calculated on a units-of-production basis. Estimates of proved developed producing reserves are a major component of the calculation of depletion. We adjust our depletion rates semi-annually based upon mid-year and year-end reserve reports, except when circumstances indicate that there has been a significant change in reserves or costs. Depreciation, depletion, and amortization decreased for the quarter ended June 30, 2020 as compared to the same period in 2019, 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 as well as oil and natural gas property impairments recorded in the first quarter of 2020.

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, 2020, general and administrative expenses decreased as compared to the same period in 2019, primarily due to a $3.0 million decrease in cash compensation and a $1.0 million decrease in equity-based compensation resulting from the broad workforce reduction in the first quarter of 2020. The overall decrease was partially offset by a $1.1 million increase in allowance, recorded in the second quarter of 2020, against an outstanding long-term receivable.

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

Six Months Ended June 30, 2020 Compared to Six Months Ended June 30, 2019

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

	Six Months Ended June 30,			
	2020	2019	Variance	
	(Dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)	2,027	2,424	(397)	(16.4)%
Natural gas (MMcf)[1]	36,702	39,209	(2,507)	(6.4)%
Equivalents (MBoe)	8,144	8,959	(815)	(9.1)%
Equivalents/day (MBoe)	44.7	49.5	(4.8)	(9.7)%
Realized prices, without derivatives:				
Oil and condensate ($/Bbl)	$ 38.24	$ 54.37	$ (16.13)	(29.7)%
Natural gas ($/Mcf)[1]	1.82	2.94	(1.12)	(38.1)%
Equivalents ($/Boe)	$ 17.74	$ 27.58	$ (9.84)	(35.7)%
Revenue:				
Oil and condensate sales	$ 77,510	$ 131,776	$ (54,266)	(41.2)%
Natural gas and natural gas liquids sales[1]	66,953	115,282	(48,329)	(41.9)%
Lease bonus and other income	6,283	12,362	(6,079)	(49.2)%
Revenue from contracts with customers	150,746	259,420	(108,674)	(41.9)%
Gain (loss) on commodity derivative instruments	70,837	(11,996)	82,833	690.5 %
Total revenue	$ 221,583	$ 247,424	$ (25,841)	(10.4)%
Operating expenses:				
Lease operating expense	$ 7,120	$ 9,141	$ (2,021)	(22.1)%
Production costs and ad valorem taxes	21,931	29,042	(7,111)	(24.5)%
Exploration expense	24	308	(284)	(92.2)%
Depreciation, depletion, and amortization	42,375	57,558	(15,183)	(26.4)%
Impairment of oil and natural gas properties	51,031	—	51,031	NM[2]
General and administrative	23,357	35,561	(12,204)	(34.3)%
Other expense:				
Interest expense	7,391	11,177	(3,786)	(33.9)%

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

[2] Not meaningful.

Revenue

Total revenue for the six months ended June 30, 2020 decreased compared to the corresponding prior period. The decrease in total revenue is primarily due to a decrease in oil and condensate sales and natural gas and NGL sales as a result of lower realized commodity prices and lower production volumes, and a decrease in lease bonus and other income. The overall decrease in total revenue was partially offset by a gain from our commodity derivative instruments for the six months ended June 30, 2020, compared to a loss in the same period in 2019.

Oil and condensate sales. Oil and condensate sales during the six months ended June 30, 2020 decreased compared to the corresponding prior period due to lower realized commodity prices and lower production volumes. The decrease in oil and condensate production was primarily driven by lower production volumes in the Bakken/Three Forks. Our mineral and royalty interest oil and condensate volumes accounted for 92% and 93% of total oil and condensate volumes for the six months ended June 30, 2020 and 2019, respectively.

Natural gas and natural gas liquids sales. Natural gas and NGL sales during the six months ended June 30, 2020 decreased compared to the corresponding prior period due to lower realized commodity prices and lower production volumes. The decrease in natural gas and NGL production was primarily driven by lower volumes in the Haynesville/Bossier play. Mineral and royalty interest production accounted for 74% and 67% of our natural gas volumes for the six months ended June 30, 2020 and 2019, respectively.

Gain (loss) on commodity derivative instruments. During the six months ended June 30, 2020, we recognized a gain from our commodity derivative instruments compared to a loss in the same period in 2019. In the six months ended June 30, 2020, we recognized $45.5 million of realized gains and $25.3 million of unrealized gains from our oil and natural gas commodity contracts, compared to $4.7 million of realized gains and $16.7 million of unrealized losses in the same period in 2019. The unrealized gains on our commodity contracts during the six months ended June 30, 2020 were primarily driven by changes in the forward commodity price curves for oil. The unrealized losses on our commodity contracts during the corresponding period in 2019 were primarily driven by changes in the forward commodity price curves for oil, partially offset by changes in the forward commodity price curves for natural gas.

Lease bonus and other income. Lease bonus and other income for the six months ended June 30, 2020 was lower than the same period in 2019. Leasing activity in the Permian Basin, Green River Basin, and Bakken/Three Forks made up the majority of lease bonus revenue in the six months ended June 30, 2020, while a substantial portion of the activity in the corresponding prior period came from the Permian Basin, as well as the Bakken/Three Forks, Wilcox, and Woodbine trends.

Operating and Other Expenses

Lease operating expense. Lease operating expense decreased for the six months ended June 30, 2020 as compared to the same period in 2019, primarily due to lower nonrecurring service-related expenses, including workovers, as well as 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, 2020, production costs and ad valorem taxes decreased as compared to the six months ended June 30, 2019, primarily as a result of lower commodity prices and lower production volumes.

Exploration expense. Exploration expense for the six months ended June 30, 2020 was minimal. Exploration expense for the six months ended June 30, 2019 primarily related to costs incurred to acquire 3-D seismic information related to our mineral and royalty interests from a third-party service provider.

Depreciation, depletion, and amortization. Depreciation, depletion, and amortization decreased for the six months ended June 30, 2020 as compared to the same period in 2019, 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 as well as oil and natural gas property impairments recorded in the first quarter of 2020.

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, 2019.

General and administrative. For the six months ended June 30, 2020, general and administrative expenses decreased as compared to the same period in 2019, primarily due to a $4.8 million decrease in cash compensation and a $13.0 million decrease in equity-based compensation. The decrease in cash compensation is primarily resulting from the broad workforce reductions in the first quarter of 2020. The decrease in equity-based compensation is due in part to these same workforce reductions but also due to downward cost revisions recognized in the six months ended June 30, 2020 for performance-based incentive awards due to the decrease in our common unit price period over period. The overall decrease was partially offset by $4.8 million of restructuring charges in the first quarter of 2020 associated with the workforce reductions and a $1.1 million increase in allowance, recorded in the second quarter of 2020, against an outstanding long-term receivable.

Interest expense. Interest expense was lower in the six months ended June 30, 2020 than in the prior period primarily due to lower interest rates and lower average outstanding borrowings under our Credit Facility.

Liquidity and Capital Resources

Overview

Our primary sources of liquidity are cash generated from operations, borrowings under our Credit Facility, 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, 2020, we had outstanding borrowings of $323.0 million under the Credit Facility. In July 2020, we closed two separate transactions to sell certain mineral and royalty properties in the Permian Basin for total proceeds, after closing adjustments, of $150.1 million. Proceeds from the asset sales were used to reduce outstanding borrowings under our Credit Facility and as of July 31, 2020, we had outstanding borrowings of $153.0 million under the Credit Facility. In connection with the closing of these asset sales, the borrowing base under the Credit Facility was reduced from $460.0 million to $430.0 million, effective July 21, 2020.

The Board has adopted a policy pursuant to which, at a minimum, distributions will be paid on each common unit for each quarter to the extent we have sufficient cash generated from our operations after establishment of cash reserves, if any, and after we have made the required distributions to the holders of our outstanding preferred units. However, we do not have a legal or contractual obligation to pay distributions on our common units quarterly or on any other basis, and there is no guarantee that we will pay distributions to our common unitholders in any quarter. The Board may change the foregoing distribution policy at any time and from time to time. In light of the challenging business environment and uncertainty caused by the pandemic, the Board approved a reduction in the quarterly distribution for the first quarter of 2020 to increase the amount of retained free cash flow for debt reduction and balance sheet protection. The Board approved an increase in the quarterly distribution for the second quarter of 2020 but the distribution remains below 2019 levels. If our borrowings exceed our borrowing base, our ability to pay cash distributions to our unitholders will be limited.

We intend to finance our future acquisitions with cash generated from operations, borrowings from our Credit Facility, 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. Replacement capital expenditures are expenditures necessary to replace our existing oil and natural gas reserves or otherwise maintain our asset base over the long-term. The Board established a replacement capital expenditure estimate of $11.0 million for the period of April 1, 2018 to March 31, 2019. Due to the expiration of the subordination period, we do not intend to establish a replacement capital expenditure estimate for periods subsequent to March 31, 2019.

Cash Flows

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

	Six Months Ended June 30,		
	2020	2019	Change
	(in thousands)		
Cash flows provided by operating activities	$ 157,969	$ 200,976	$ (43,007)
Cash flows provided by (used in) investing activities	367	(46,013)	46,380
Cash flows used in financing activities	(164,855)	(156,471)	(8,384)

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, 2020 as compared to the same period of 2019. The decrease was primarily due to decreased oil and condensate sales and natural gas and NGL sales driven by lower realized commodity prices and lower production for the six months ended June 30, 2020 compared to the same period of 2019. The overall decrease was partially offset by higher net cash received on settlement of commodity derivative instruments.

Investing Activities. Net cash was provided by investing activities in the six months ended June 30, 2020 as compared to net cash used in investing activities in the same period of 2019. The change was primarily due to reduced oil and natural gas property acquisitions and expenditures, net of farmout reimbursements, and higher proceeds from the sale of oil and natural gas properties in the six months ended June 30, 2020.

Financing Activities. Cash flows used in financing activities increased for the six months ended June 30, 2020 as compared to the same period of 2019. The increase was primarily due to net repayments under our Credit Facility in the six months ended June 30, 2020 as compared to net borrowings in the corresponding prior period. The overall increase was partially offset by lower distributions to common and subordinated unitholders and decreased repurchases of common units.

Development Capital Expenditures

Our 2020 total development capital expenditure budget associated with our non-operated working interests is expected to be approximately $3.5 million, net of farmout reimbursements, of which $0.9 million has been invested in the six months ended June 30, 2020. The majority of this capital will be spent for workovers on existing wells in which we own a working interest.

Credit Facility

Pursuant to our $1.0 billion senior secured revolving credit agreement, as amended (the “Credit Facility”), the commitment of the lenders equals the lesser of the aggregate maximum credit amounts of the lenders and the borrowing base, which is determined based on the lenders’ estimated value of our oil and natural gas properties. Borrowings under the Credit Facility may be used for the acquisition of properties, cash distributions, and other general corporate purposes. Our Credit Facility terminates on November 1, 2022. As of June 30, 2020, we had outstanding borrowings of $323.0 million at a weighted-average interest rate of 2.43%.

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 October 23, 2019 the borrowing base redetermination reduced the borrowing base from $675.0 million to $650.0 million, effective May 1, 2020, the borrowing base was reduced to $460.0 million. Effective July 21, 2020, in connection with the closing of our two asset sales in the Permian Basin, the borrowing base was further reduced to $430.0 million. The next borrowing base redetermination is expected in the fall of 2020. If operators continue to shut-in production and commodity prices remain at current levels, our borrowing base could be further reduced.

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

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

Our credit agreement contains various affirmative, negative, and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates, and entering into certain derivative agreements, as well as require the maintenance of certain financial ratios. The credit agreement contains two financial covenants: total debt to EBITDAX of 3.5:1.0 or less and a current ratio of 1.0:1.0 or greater as defined in the credit agreement. Distributions are not permitted if there is a default under the credit agreement (including the failure to satisfy one of the financial covenants) or during any time that our borrowing base is lower than the loans outstanding under the credit agreement. The lenders have the right to accelerate all of the indebtedness under the credit agreement upon the occurrence and during the continuance of any event of default, and the credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy, and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods. As of June 30, 2020, we were in compliance with all debt covenants.

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

Contractual Obligations

As of June 30, 2020, there have been no material changes to our contractual obligations previously disclosed in our 2019 Annual Report on Form 10-K.

Off-Balance Sheet Arrangements

As of June 30, 2020, we did not have any material off-balance sheet arrangements.

Critical Accounting Policies and Related Estimates

As of June 30, 2020, there have been no significant changes to our critical accounting policies and related estimates previously disclosed in our 2019 Annual Report on Form 10-K.

New and Revised Financial Accounting Standards

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

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

To estimate the effect lower prices would have on our reserves, we reduced the SEC commodity pricing for the six months ended June 30, 2020 by 10%. This results in an approximate 4.3% reduction of proved reserve volumes as compared to the unadjusted June 30, 2020 SEC pricing scenario.

Counterparty and Customer Credit Risk

Our derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require our counterparties to our derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as we deem appropriate. This evaluation includes reviewing a counterparty's credit rating and latest financial information. As of June 30, 2020, we had nine counterparties, all of which were rated Baa1 or better by Moody's and are lenders under our Credit Facility.

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

Interest Rate Risk

We have exposure to changes in interest rates on our indebtedness. As of June 30, 2020, we had $323.0 million of outstanding borrowings under our Credit Facility, bearing interest at a weighted-average interest rate of 2.43%. The impact of a 1% increase in the interest rate on this amount of debt would have resulted in an increase in interest expense, and a corresponding decrease in our results of operations, of $1.6 million for the six months ended June 30, 2020, assuming that our indebtedness remained constant throughout the period. We may use certain derivative instruments to hedge our exposure to variable interest rates in the future, but we do not currently have any interest rate hedges in place.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (the "Exchange Act"), we have evaluated, under the supervision and with the participation of management of our general partner, including our general partner's principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report on Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our general partner's principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our general partner's principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of June 30, 2020.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended June 30, 2020 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

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

Risks Related to our Business

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

The COVID-19 pandemic has adversely affected the global economy, disrupted global supply chains and created significant volatility in the financial markets. In addition, the pandemic has resulted in travel restrictions, business closures and the institution of quarantining and other restrictions on movement in many communities. As a result, there has been a significant reduction in demand for and prices of oil, natural gas and natural gas liquids ("NGLs"). In the first quarter of 2020 and into the second quarter of 2020, oil prices fell sharply and dramatically, due in part to significantly decreased demand as a result of the COVID-19 pandemic and the announcement by Saudi Arabia of a significant increase in its maximum oil production capacity as well as the announcement by Russia that previously agreed upon oil production cuts between members of the Organization of the Petroleum Exporting Countries and its broader partners (“OPEC+”) would expire on April 1, 2020, and the ensuing expiration thereof. Agreed-upon production cuts by OPEC+ along with declining U.S. production have helped to correct the supply and demand imbalance; however, these reductions are not expected to be enough in the near-term to offset the significant inventory build caused by demand destruction from the COVID-19 pandemic in the first half of 2020. Prices for oil were over $60 per barrel at the beginning of 2020 before declining significantly through March and further declining into April. While oil prices modestly recovered in June and July 2020, a reversal of recent improvements or a prolonged period at current prices may materially and adversely affect our financial condition, results of operations, and cash distributions to unitholders.

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

The current price environment also caused us to determine that certain depletable units consisting of mature oil producing properties were impaired. Therefore, we recognized impairment of oil and natural gas properties of $51.0 million for the six months ended June 30, 2020. Additionally, the borrowing base under the Credit Facility, which takes into consideration the estimated loan value of our oil and natural gas properties, was reduced from $650.0 million to $460.0 million, effective May 1, 2020. Effective July 21, 2020, in connection with the closing of our two asset sales in the Permian Basin, the borrowing base was further reduced to $430.0 million. In a prolonged period of low commodity prices, we may be required to impair additional properties and the borrowing base under our Credit Facility could be further reduced. In light of the challenging business environment and uncertainty caused by the pandemic, the board of directors of our general partner (the "Board") also approved a reduction in the quarterly distribution for the first quarter of 2020 to increase the amount of retained free cash flow for debt reduction and balance sheet protection. The Board approved an increase in the quarterly distribution for the second quarter of 2020 but the distribution remains below 2019 levels.

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

To protect the health and well-being of our workforce in the wake of COVID-19, we have implemented remote work arrangements for all employees. To the extent circumstances require us to maintain remote work arrangements indefinitely, our operational efficiency could be adversely affected, which could in turn adversely affect our financial condition and results of operations.

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

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

Recent Sales of Unregistered Securities

None.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

None.

Item 5. Other Information

None.

Item 6. Exhibits

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

* Filed or furnished herewith.

SIGNATURES

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

BLACK STONE MINERALS, L.P.

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

Date: August 4, 2020	By:	/s/ Thomas L. Carter, Jr.
		Thomas L. Carter, Jr.
		Chief Executive Officer and Chairman
		(Principal Executive Officer)
Date: August 4, 2020	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 4, 2020

/s/ Thomas L. Carter, Jr.

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

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 4, 2020

/s/ Jeffrey P. Wood

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

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 4, 2020

/s/ Thomas L. Carter, Jr.

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

Date: August 4, 2020

/s/ Jeffrey P. Wood

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